

REDACTED
Rocky Mountain Power
Docket No. 10-035-124
Witness: Stefan A. Bird

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Redacted Rebuttal Testimony of Stefan A. Bird

REC Revenues & Hedging

June 2011

1 **Q. Are you the same Stefan A. Bird who submitted direct testimony in this**
2 **proceeding?**

3 A. Yes.

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

5 A. My rebuttal testimony addresses three separate issues in this case.

6 Section I of my testimony addresses the reasonableness of the Company's
7 Renewable Energy Credit (REC) revenue forecast. In Section I, I update the REC
8 revenues in this case and respond to the adjustments on REC revenues presented
9 by Ms. Brenda Salter on behalf of the Utah Division of Public Utilities ("DPU"),
10 Ms. Donna Ramas on behalf of the Utah Office of Consumer Services ("OCS"),
11 Mr. Kevin Higgins on behalf of UAE Intervention Group ("UAE"), and Mr.
12 Roger Swenson on behalf of US Magnesium LLC.

13 Section II of my testimony addresses the Company's hedging strategy and
14 practices and demonstrates why the associated costs are prudent and reasonable.
15 In Section II, I respond to the adjustments for hedging costs proposed by Messrs.
16 Douglas D. Wheelwright and Mark W. Crisp on behalf of the DPU;¹ Ms. Michele
17 Beck and Dr. Lori Smith Schell and Mr. Paul J. Wielgus on behalf of the OCS;
18 Messrs. Kevin Higgins and Jeff L. Fishman on behalf of UAE; and Messrs. J.
19 Robert Malko and Mark T. Widmer on behalf of Utah Industrial Energy
20 Consumers (UIEC). Company witnesses Messrs. John A. Apperson and Gregory
21 N. Duvall and Mr. Frank C. Graves from The Brattle Group join me in responding

¹ Mr. George W. Evans, the net power cost witness for the DPU, reflects Mr. Wheelwright's hedging adjustment in his overall net power costs calculation, but does not independently address the hedging issue. In reflecting Mr. Wheelwright's adjustment in his testimony, Mr. Evans misstates (and doubles) the adjustment.

22 to particular aspects of the hedging adjustments proposed by intervenors.

23 Section III of my testimony briefly addresses the Company's decision to
24 terminate negotiations to acquire the Apex project in the All Source RFP. DPU
25 witness Mr. Charles E. Petersen incorporates my testimony from Docket No. 10-
26 035-126 in this case. Company witness Mr. Duvall provides the primary
27 testimony responding to various issues raised by Mr. Petersen.

28 **Section I REC Revenues**

29 **Q. Please summarize your rebuttal testimony on REC revenue.**

30 A. I cover the following issues in this section of my rebuttal testimony:

- 31 • I update the test period REC revenue forecast to \$86.1 million, an increase
32 of \$30.4 million from my direct testimony.
- 33 • I provide background on recent developments in the REC markets in the
34 Western Electric Coordinating Council (WECC) and explain how they
35 validate the Company's REC revenue forecast in this case.
- 36 • I support the general proposal from the DPU and OCS for a mechanism to
37 track actual REC revenues for inclusion in rates.
- 38 • I respond to the adjustments sponsored by the DPU, OCS and UAE to
39 increase forecasted REC revenues. I demonstrate that these adjustments
40 are unrealistic because their proposed prices are well above market and
41 their proposed volumes do not take into account the volatility in the output
42 of the Company's wind resources.
- 43 • I respond to the adjustment sponsored by US Magnesium, based upon its
44 proposal that the Company sell all of the output of its renewable energy

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49 **Update to REC Revenue from Direct Testimony**

50 **Q. What is the Company's updated forecast for revenue from the sale of RECs**
51 **in the test period?**

52 A. The Company forecasts REC revenues of \$86.1 million on a total Company basis
53 or \$50.9 million on a Utah-allocated basis. Company witness Mr. Steven R.
54 McDougal provides the details of the allocation of total Company REC revenue to
55 Utah.

56 **Q. How does the updated forecast compare to the REC revenue forecast in your**
57 **direct testimony?**

58 A. My direct testimony included \$55.7 million of REC revenue on a total Company
59 basis, or \$32.9 million on a Utah-allocated basis.

60 **Q. Please explain the increase in REC revenues from \$55.7 million to \$86.1**
61 **million.**

62 A. My direct testimony included two known transactions forecasted at 982,800 MWh
63 of RECs or \$41.9 million; 1,677,463 MWh of forecasted excess net marketable
64 wind at \$7.00MWh or \$11.7 million; and 509,796 MWh forecasted vintage wind
65 at \$4.00 per MWh or \$2.0 million for a total REC revenue of \$55.7 million. My
66 direct testimony discussed the possibility of a third major transaction resulting
67 from the NV Energy Short-Term RFP, and promised to update the REC revenue

68 forecast if the Company was successful in this RFP.

69 On February 9, 2011, the Company executed this third transaction. This
70 increased the forecast of known transactions from \$41.9 million to \$78.0 million.
71 It also reduced the forecasted excess net marketable wind to 875,348 MWh at
72 \$7.00/MWh or \$6.1 million. The forecasted vintage wind remained the same at
73 509,796 MWh at \$4.00/MWh or \$2.0 million. This results in total REC revenues
74 of \$86.1 million for the test period.

75 **Q. Your direct testimony explained the Company's calculation of forecast REC**
76 **revenues. Does your rebuttal update reflect any changes to this calculation?**

77 A. No. The update simply reflects an increase in known transactions and a
78 corresponding decrease in incremental sales.

79 **Q. Your updated forecast retains the \$7.00/MWh price for incremental sales.**
80 **What evidence did the Company rely upon in determining that this price**
81 **remains appropriate?**

82 A. For the voluntary market, the Company estimated \$7.00/MWh price using recent
83 broker quotes on standalone RECs. Because the market is so illiquid, the bid ask
84 spread is \$4.00/MWh to \$7.00/MWh. Exhibit RMP____(SAB-1R) is a recent
85 broker quote demonstrating the continuing validity of this forecast price.

86 For the compliance market, the estimated \$7.00/MWh [REDACTED]
87 [REDACTED]
88 [REDACTED]

89 **Q. Please describe the RFP the Company issued for RECs on May 25, 2011.**

90 On May 25, 2011, the Company issued a request for proposals (RFP) for RECs

91 needed for compliance purposes for a term of 2012 through 2015 with a
92 maximum quantity of 30,000 MWh. The Company received a robust response to
93 this RFP with a range of pricing and terms. The evaluation of the RFP is now
94 complete and the Company is poised to execute several transactions all at REC
95 prices [REDACTED]

96 [REDACTED]

97 **The WECC and California Renewable Markets**

98 **Q. Your direct testimony explained why developments in the California REC**
99 **market made additional negotiated contracts for the test period uncertain.**
100 **Please summarize the current status of WECC REC markets.**

101 A. Since I filed my direct testimony, there have been a number of developments in
102 California which impact the WECC REC markets. In summary, these
103 developments have restricted the Company's ability to make additional negotiated
104 REC sales and have reduced prices for any such potential sales during the test
105 period.

106 **Q. Please explain what has transpired since January 14, 2011, when the**
107 **California Public Utility Commission issued Decision 11-01-025, described in**
108 **your direct testimony.**

109 A. On February 1, 2011, Senate Bill No. 2 of the California Legislature 2011-2012
110 First Extraordinary Session ("SB 2x") was introduced. It was eventually passed
111 by the California Legislature and was signed by Governor Brown on April 12,
112 2011. A copy of the law is attached as Exhibit RMP___(SAB-3R).

113 **Q. Has SB 2x become effective?**

114 A. No. SB 2x will become effective on the 91st day following close of the First
115 Extraordinary Session, which remains in session. I understand that, by default, a
116 special session cannot extend beyond the regular legislative session, and the latest
117 that SB 2x could become effective is February 28, 2013. However, it is expected
118 that the current special session will be adjourned sometime this summer. Even if
119 the budget is addressed by mid-July, and the Extraordinary Session closed
120 promptly thereafter, SB 2x would not become effective until mid-October.
121 Because of the ongoing delay, there is uncertainty in the renewables market as to
122 2011 procurement targets and other changes enacted by SB 2x.

123 **Q. What were the major changes to the California Renewable Portfolio**
124 **Standard (RPS) made by SB 2x?**

125 A. Major changes included an expanded RPS procurement goal of 33 percent by
126 2020; expansion of the compliance obligation to publicly owned utilities; use of
127 multi-year compliance period with incremental procurement targets; enactment of
128 statutory excuses for procurement shortfalls; designation of procurement
129 “product” types; and the specification of a minimum and maximum product type
130 content for retail sellers’ RPS portfolios, which change with each compliance
131 period. The latter two changes both impose a preference for in-state resources and
132 modify delivery and other requirements for use of out-of-state resources.
133 Additionally, retail sellers’ ability to bank RPS procurement surpluses is restricted
134 by the inability to carry forward short-term transactions or Tradable RECs
135 (“TRECs”).

136 **Q. What is required to implement SB 2x and what are the associated timelines?**

137 A. The legislation requires implementation by the California Energy Commission
138 (CEC), which certifies resources program eligibility and verifies annual
139 production levels, and the California Public Utilities Commission (CPUC), which
140 oversees RPS program compliance by jurisdictional entities such as the Investor-
141 Owned Utilities (IOU), Energy Service Providers (ESP), and Community Choice
142 Aggregators (CCA). The California Air Resources Board will also conduct
143 rulemakings in its new capacity as a regulator with respect to publicly owned
144 utilities. It is also likely that additional implementation action may be required by
145 the Western Renewable Energy Generation Information System (WREGIS).² The
146 full implementation process is anticipated to take approximately 18 months to 2
147 years, although further delays are possible given the number of agencies involved.

148 **Q. Please explain the new RPS targets and compliance requirements.**

149 A. There are three compliance periods, each of which has different compliance
150 requirements and specific caps for the three types of RPS Products (Products)
151 eligible to meet RPS compliance requirements. The three compliance periods are:
152 (1) 20 percent average procurement target from January 1, 2011 through
153 December 31, 2013; (2) 25 percent procurement required by the end of 2016; and
154 (3) 33 percent from January 1, 2017 through December 31, 2020.

155 **Q. Did SB 2x change California's approach to RPS noncompliance?**

156 A. Yes. SB 2x's approach to noncompliance is more flexible and less punitive than

² SB 2x creates different types of RPS products that have corresponding procurement requirements or limitation. Since some of these product definitions are associated with the manner that out of state resources are imported into California, it is foreseeable that tracking of WREGIS Certificates by delivery process may be necessary.

157 was previously the case. California's RPS previously required payment of a
158 penalty for noncompliance, and required noncompliant utilities to make up any
159 deficit in the next compliance period. SB 2x provides new statutory excuses for
160 noncompliance (such as inadequate transmission capacity and delays in
161 interconnection and permitting) and does not require the deficit to be made up in
162 the next compliance period.

163 **Q. How will SB 2x impact the REC market during the test period in this case?**

164 A. SB 2x and most particularly its pending effective date and the three separate state
165 agency rulemakings with respect to its implementation, have continued the period
166 of deep uncertainty in the California REC market. Even though the rulemakings at
167 the three state agencies are now underway, they are proceeding under a cloud of
168 uncertainty given SB 2x's not-yet-effective status.

169 **Q. Will the Company respond to the three California IOUs' RFPs for renewable
170 resources?**

171 A. Yes, however, due to the uncertainty around the effective date of SB 2x and the
172 pending rulemakings, there is some reason to believe that the RFPs will be more
173 informational for the California IOUs than real at least for the near future. The
174 Company is not optimistic that any transactions will occur under the RFPs until
175 the later part of 2012, which is after the test period in this case. While the
176 Company hopes to transact with one of the California IOUs through the RFPs and
177 achieve a better price for its RECs than now otherwise available, this possibility is
178 too uncertain to serve as a basis for adjusting the Company's forecast upward. It
179 is this uncertainty that informs the Company's support of a tracking mechanism,

180 as I discuss below.

181 **Q. If the Company cannot participate in the California market, in which**
182 **markets will it participate?**

183 A. The voluntary market for REC sales in the Northwest is likely to be the only other
184 market.

185 **Q. What about the potential for future sales to Nevada Power?**

186 A. The prior opportunistic sale to Nevada Power was done under Nevada Power's
187 request for proposals. In addition, Nevada Power has not indicated that they will
188 be issuing a request for proposals or have additional requirements post the
189 expiration of the existing transaction. Any additional opportunistic sales would be
190 outside of the test period.

191 **REC Tracker Mechanism**

192 **Q. Given the uncertainty in the WECC REC markets highlighted above, does**
193 **the Company support the tracking of actual REC revenues for ratemaking as**
194 **proposed by the DPU and OCS?**

195 A. Yes. The Company has consistently taken the position that the Commission
196 should track both actual REC revenues and actual net power costs for purposes of
197 reflecting these items in rates. The Company recently implemented a separate
198 REC tracker mechanism in Wyoming, and another is pending before the
199 Washington Commission.

200 **Q. The Commission excluded REC revenues from the Company's Energy**
201 **Balancing Account (EBA). Has this impacted the Company's view of the**
202 **appropriateness of separately tracking actual REC revenues for inclusion in**
203 **rates?**

204 A. Yes. Given the Commission's decision excluding RECs from the EBA, the
205 Company is not opposed to adoption of a separate tracking mechanism. The
206 Company agrees with the DPU that the EBA and the REC tracking mechanism
207 should operate in a coordinated manner. Mr. McDougal addresses additional
208 details on the mechanics of the tracking mechanism.

209 **Responses to Intervenor Adjustments on REC Revenues**

210 **Q. The DPU, OCS and UAE each propose adjustments to increase the REC**
211 **revenue forecast. Why is the Company's current REC revenue forecast,**
212 **including the \$6.1 million in incremental REC sales in the test period, more**
213 **realistic than the alternatives proposed by the DPU, OCS and UAE?**

214 A. There is no disagreement among the parties for the portion of the REC forecast
215 based upon known transactions. With respect to incremental sales, the Company's
216 REC revenue forecast is based upon sales of 75 percent of the net marketable
217 production from the renewable resource at a price of \$7.00/MWh for current
218 RECs and \$4.00/MWh for vintage RECs. The DPU, OCS and UAE all substitute
219 a higher price for incremental sales. The Company's price forecast, however, was
220 based upon actual market data for the broker markets and was recently validated
221 by the Company's REC RFP.

222 The OCS also challenges the Company's estimated sales volume, arguing

223 that it should forecast sales of 90 percent of net marketable product. The
224 Company sells only 75 percent of the forecast wind RECs on a forward basis to
225 ensure that it can perform under any contracts, bundled or unbundled, that it may
226 enter into. Based on the Company's experience and the wind data we have
227 received, selling 75 percent of the forecast output ensures the Company can
228 perform under its contracts and avoids the risk of liquated damages or other
229 nonperformance penalties.

230 **Q. Why is the DPU proposal to substitute the Company's forecast sales price of**
231 **\$7.00/MWh and \$4.00/MWh to the actual average sales price in 2010**
232 **unreasonable?**

233 A. The DPU's proposal uses a price drawn predominantly from three large executed
234 transactions in 2010 and applies it to the forecast for incremental sales in the test
235 period. The executed transactions are very different in kind than the incremental
236 sales the Company may make in the test period. The three executed transactions
237 in 2010 are very highly structured, limited opportunities. Two of the three
238 executed transactions were originally executed in 2009. The third was a limited
239 opportunity through an RFP which the counterparty only issued to fill a temporary
240 resource gap to meet its RPS requirement. The Company's broker quotes and
241 REC RFP are much more accurate predictors of REC sales prices for the
242 incremental sales in the test period than prices drawn from the unique executed
243 transactions in 2010.

244 **Q. Why is the OCS adjustment substituting a \$36.00/MWh price and increasing**
245 **the forecast sale from 75 percent to 90 percent unreasonable?**

246 A. The OCS has produced no support for its proposed price other than evidence
247 drawn from past, noncomparable REC sales. Nor has OCS provided any basis for
248 disregarding the Company's 75 percent sales threshold, which is required to
249 protect against overselling RECs in light of variable wind performance. The
250 Company's REC sales transactions require the delivery of firm RECs. To receive
251 full value for its REC sales, the Company is subject under its sales contracts to
252 liquidated damages of up to \$50/MWh for nonperformance of delivery of firm
253 RECs. In light of these factors, it is inappropriate to forecast sales revenues at
254 volume levels higher than those that are realistically and prudently achievable.

255 **Q. Please respond to UAE's proposal to reprice 50 percent of incremental sales**
256 **at 90 percent of known transactions in test period.**

257 A. UAE assumes that the price that the Company has obtained for the executed
258 transactions in the test period can be replicated for one-half of remaining
259 incremental sales. This ignores the developments in California and their impact on
260 the REC market, the Company's broker quotes and the proposals the Company is
261 evaluating as a result of the Company's REC RFP.

262 **Q. Please respond to the adjustment proposed by US Magnesium based upon**
263 **the assumed sale of all of the Company's renewable resources for terms of 5**
264 **to 10 years.**

265 A. As stated in my direct testimony, the Company acquires wind resources primarily
266 to serve its growing need for new resources on a diversified basis consistent with

267 its integrated resource plan. This is consistent with the Company's duty to serve
268 customers with reliable, reasonably priced utility service. The adjustment
269 proposed by US Magnesium effectively seeks to convert the Company from an
270 electric utility service provider into a REC broker on behalf of its customers.

271 **Q. Did the Utah Commission acknowledge the Company's most recent IRP,**
272 **which included its renewable resources as a power supply source (not just a**
273 **REC sales supply source) for its customers?**

274 A. Yes. See Report and Order, Docket No. 09-2035-01 (April 1, 2010).

275 **Q. Did US Magnesium participate in the Company's IRP and make its proposal**
276 **for sale of all renewable resources in that context?**

277 A. No.

278 **Q. US Magnesium's adjustment assumes sales of renewable resources for 5 to 10**
279 **years. Is there a market for REC sales of this length?**

280 A. The Company's REC sales are supported by its full portfolio of renewable
281 resources to optimize existing surplus resources and RECs and are not earmarked
282 to a single resource. The Company's experience is these sales are limited in
283 duration. The longest REC sales transaction the Company has ever executed is
284 less than five years in duration. More commonly thus far, the transactions are one
285 to two years in duration. US Magnesium has not provided evidence of the
286 existence of the market in which they urge the Company to transact.

287 **Section II Hedging Issues**

288 **Q. Please summarize your testimony and the testimony of the Company's other**
289 **hedging witnesses.**

290 A. My testimony provides the Company's overall response to the intervenors'
291 criticism of the Company's hedging program. I first provide a general description
292 of the Company's risk management policy and hedging program, explaining what
293 they are and how they work. Next, I provide the context for the hedging
294 adjustments in this case, including the previous regulatory review of these issues
295 in Utah and the prudence standard applicable to their review. Then, I correct the
296 record on the major misstatements of fact underlying intervenors' adjustments,
297 explain the serious policy flaws inherent in their adjustments and demonstrate the
298 overall prudence of the Company's hedging program.

299 Mr. Graves from The Brattle Group provides independent expert
300 testimony corroborating the prudence of the Company's hedging program, in light
301 of electric utility industry norms and standards. Additionally, Mr. Graves also
302 provides perspectives on the changes in the natural gas markets and unforeseeable
303 nature of the current low prices. Finally, Mr. Graves provides his opinion on the
304 most effective and fair way for the Utah Commission to review and monitor the
305 Company's hedging program.

306 Mr. Apperson responds to the adjustments presented by the intervenors,
307 based upon his expertise as the Company's Director of Trading. Mr. Apperson
308 sponsors the quantitative analysis the Company relies upon to rebut intervenors'
309 adjustments and provides additional evidence on the reasonableness of the

310 Company's hedge horizon. He also explains that the Company could not have
311 reasonably foreseen the drop in natural gas prices which caused the hedging
312 losses in this case, responds to the OCS's proposal to substitute the use of natural
313 gas options for natural gas and power swaps, addresses issues raised about other
314 costs of hedging, including cash collateral and explains how the hedge program
315 responds to fluctuations in loads.

316 Finally, Mr. Duvall quantifies the impact of the Company's hedging
317 program on net power costs in Utah rates and demonstrates that the hedging
318 program has reduced the volatility and overall level of the Company's net power
319 costs.

320 **Overview of Company's Risk Management Policy and Hedging Program**

321 **Q. What is the purpose of the Company's risk management policy?**

322 A. The goals of the Company's risk management program are to: (1) ensure that
323 reliable power is available to serve customers; (2) reduce net power cost
324 volatility; and (3) protect customers from significant risks. The Company's risk
325 management policy was designed to follow electric industry best practices and is
326 periodically reviewed and updated as necessary.

327 **Q. What are the main components of the Company's risk management policy?**

328 A. As outlined in the Company's risk policy, the main components of the Company's
329 risk management of fuel and power price volatility are value-at-risk ("VaR")
330 measurements and VaR limits, position limits, and stop-loss limits. These limits
331 force the Company to monitor the open positions it holds in power and natural gas
332 on behalf of its customers on a daily basis and limit the size of these open

333 positions by prescribed time frames in order to reduce customer exposure to price
334 concentration and price volatility.

335 The Company has a large short position in natural gas because of its
336 ownership of gas-fired electric generation, requiring it to purchase large quantities
337 of natural gas to generate power for its customers. The risk policy requires the
338 Company to purchase natural gas well in advance of when it is required to reduce
339 the size of this short position. Likewise, on the power side, the Company either
340 purchases or sells power in advance of anticipated open short or long positions to
341 manage price volatility on behalf of customers.

342 **Q. What is the purpose of the Company's hedging program?**

343 A. The hedging program supplements and is subordinate to the Company's risk
344 policy by specifying separate to-expiry VaR calculation and targets. As stated in
345 the Company's most recent Integrated Resource Plan ("IRP"), "Hedging is done
346 solely for the purpose of limiting financial losses due to unfavorable wholesale
347 market changes....Hedging modifies the potential losses and gains in net power
348 costs associated with wholesale market price changes."³

349 **Q. Does the Company hedge its separate power or natural gas positions or its
350 net energy position?**

351 A. The Company hedges its net energy (combined natural gas and power) position to
352 take full advantage of any natural offsets between its long power and short natural
353 gas positions.⁴ The Company's 2011 IRP analysis shows that a "hedge only
354 power" or "hedge only natural gas" approach results in higher risk (*i.e.*, a wider

³ Docket No. 11-2035-01, PacifiCorp 2011 IRP, Appendix F at 161-162 (March 31, 2011).

⁴ *Id.* at 170.

355 distribution of outcomes).⁵ Mr. Apperson's testimony further explains the natural
356 need for an electric company with natural gas fired electricity generation assets to
357 have a hedge program that simultaneously manages natural gas and power open
358 positions with appropriate coordinated metrics.

359 **Q. How is the Company's hedging program structured?**

360 A. Since 2003, the Company's hedge program has employed dollar cost averaging to
361 progressively reduce net power cost risk exposure closer to delivery over a
362 defined time horizon. In May 2010, the Company moved from hedging targets
363 based on volume to targets based on the "to expiry value-at-risk" or TEVaR
364 metric. The primary goal of this change was to increase the transparency to the
365 Company's combined natural gas and power exposure by period. Importantly, the
366 TEVaR metric automatically results in reducing hedge requirements as
367 commodity price volatility decreases and increases hedge requirements as
368 correlations among commodities diverge, all the while maintaining the same risk
369 exposure.

370 **Q. Please describe the Company's hedging targets.**

371 A. These targets are set forth in Highly Confidential Exhibit RMP__(SAB-4R) both
372 on a percentage and July 2011 to June 2012 net power cost basis.

373 **Q. Has the Company's risk management policy and hedge program changed in
374 response to the development of shale gas and the decreasing price of natural
375 gas?**

376 A. Yes. The Company's risk management program has been actively reviewed by its
377 internal risk oversight committee and updated every year for several years

⁵ *Id.* at 170.

378 running to reflect best practices and respond to changing market conditions. In
379 addition, as mentioned above, the hedge program was modified in May 2010 with
380 the institution of the TEVaR metric. The result of these changes has been a
381 decrease in the Company's longer-dated hedge activity, i.e., four years forward on
382 a rolling basis, has decreased from a peak forward hedge percentage of
383 approximately ■ percent in 2008 (a period reflecting high volatility) to
384 approximately ■ percent in 2011 (a period reflecting lower volatility).

385 **Regulatory Review of Company's Risk Management Policy and Hedging Program**

386 **Q. Has the Utah Commission reviewed the Company's risk management policy**
387 **and hedging program in previous dockets?**

388 A. Yes. The Company's risk management policy and hedging program have been a
389 focus of a number of previous Commission dockets.

390 First, in May 2009, the Commission opened a docket on hedging, Docket
391 No. 09-035-21, as a result of the parties' stipulation in the Company's 2008
392 general rate case, Docket No. 08-035-38. The Commission held a technical
393 conference in May 2009 to hear Rocky Mountain Power's initial presentation
394 regarding its risk management policy and hedging program. On June 3, 2009, the
395 Commission held a second technical conference to hear a DPU-sponsored
396 presentation by a representative from the National Regulatory Research Institute
397 (NRRI) regarding different types of hedging mechanisms on and advantages and
398 disadvantages of natural gas pricing policies used by utility companies across the
399 country. In May 2010, the Company made another presentation in the docket to
400 update parties on the implementation of the TEVaR metric.

401 Second, the Company’s hedging program was the subject of extensive
402 testimony in Docket No. 09-035-15, the Company’s request for an energy cost
403 adjustment mechanism (“ECAM”) docket. The Company filed four rounds of
404 testimony in that case addressing hedging issues,⁶ and responded to dozens of
405 data requests on the issue. Because the inclusion of natural gas and power swaps
406 in the Energy Balancing Account is currently the subject of rehearing, the
407 Company will file additional testimony on these issues in July 2011.

408 Third, in the Company’s last rate case, Docket No. 09-035-23, the DPU
409 filed the results of its independent, third-party evaluation of the Company’s risk
410 management policy and hedging program. This evaluation, dated October 7, 2009,
411 was conducted by Blue Ridge Consulting Service (Blue Ridge Report).

412 Fourth, in Docket No. 09-2035-01, the Commission’s April 1, 2010 order
413 acknowledging the Company’s IRP directed the Company to include hedging
414 costs in future IRP analysis, and perform sensitivity analysis to determine a
415 hedging strategy which minimizes costs and risks for customers. The Company
416 included this analysis in its 2011 IRP, filed on March 31, 2011 in Docket No. 11-
417 2035-01.

418 In summary, the Company’s risk management policy and hedging
419 program have been the subject of ongoing regulatory review, extensive discovery
420 and testimony in several dockets since at least 2009.

⁶ Messrs. Duvall and Graves addressed hedging in their direct and rebuttal testimony on the first phase of the ECAM docket, filed in August 2009 and December 2009, respectively. In July 2010, Mr. Duvall again addressed these issues in the Company’s opening testimony in Phase 2 of the docket. Finally, I filed rebuttal testimony on hedging issues, along with Messrs. Duvall and Graves, in September 2010.

421 **Q. Some parties to this case have complained about the complexity and lack of**
422 **transparency in the Company's hedging program. Please respond.**

423 A. The Company has taken all reasonable steps to ensure that its hedging program is
424 transparent and auditable. First, the Company's hedging program is structured
425 using the most straightforward hedging instruments available: financial swaps and
426 forward contracts (*i.e.*, fixed price physical electricity and natural gas
427 transactions). Second, the Company has provided significant discovery on its
428 hedging program, responding to approximately 250 data requests on the subject in
429 the dockets cited above, and another 125 in this case.

430 **Q. At any time during these regulatory proceedings, has any party taken the**
431 **position that the Company failed to develop, implement and carry out a**
432 **prudent risk management policy?**

433 A. No. On the contrary, the most comprehensive, third-party evaluation of the
434 Company's risk management policy and hedging program, the DPU's Blue Ridge
435 Report, affirmatively concluded that the Company's risk management policy and
436 related hedging program adhered to generally accepted industry standards:

437 Overall, Blue Ridge found that the Company's commercial trading
438 and risk management programs (and the related hedging programs)
439 are well-documented and controlled and adhere to generally
440 accepted standards found elsewhere in the industry. The Company
441 has well-stated goals and strategy that is aimed at mitigating price
442 volatility. In addition, our review of the Company's internal
443 documents showed that the Company is self-monitoring
444 compliance with accepted commercial trading and risk
445 management procedures through its own internal audit function.

446 While the Company's risk management policy and hedging program have
447 continued to be refined and improved, the fundamentals of the risk policy and the

448 hedging program have not changed since the time of the DPU’s Blue Ridge
449 Report.

450 **Q. At any time during these regulatory proceedings, has any party taken the**
451 **position that the Company was imprudent to engage in hedging?**

452 A. No. While the parties in this case propose *ex post* disallowances questioning the
453 volume, length and type of hedging, no party here or elsewhere has questioned the
454 prudence of the Company engaging in hedging. Again, the DPU’s Blue Ridge
455 Report is instructive:

456 The question has been asked, “Why hedge?” The answer lies in
457 one fundamental statement: prices and supplies for energy
458 commodities (crude oil, natural gas, electricity, etc.) can and have
459 been extremely volatile. The benefit of hedging is that when prices
460 are rising (either rapidly in the short term or gradually in the long
461 term), a hedged portfolio of supply should mitigate the effect of
462 those increases. However, the opposite is also true. When prices
463 fall suddenly, a hedged portion of the supply can cost the utility
464 and its customers the difference between the prices that were
465 available at the current time versus the hedged prices for that
466 supply. This cost (when netted against any gains) along with the
467 administrative costs associated to operate and manage the trading
468 operations is considered the insurance premium associated with a
469 hedged portfolio.

* * * * *

470 [H]aving a “no hedge” policy clearly exposes consumers to
471 significant (and likely) price swings. Assuming that an upward
472 price trend continues (despite recent price levels and short-term
473 price forecasts), consumers are very likely to pay higher prices for
474 energy absent some level of hedging and price volatility
475 mitigation.

476 **Q. Is the DPU-sponsored presentation from NRRI in the Company’s hedging**
477 **docket (“NRRI Report”)⁷ also relevant to this question?**

478 A. Yes. The NRRI Report indicates that, for many years, state commissions have
479 conveyed that the failure to engage in hedging (*i.e.* buying natural gas in the day-
480 ahead market or spot price) may be imprudent.

481 **Q. Is it your understanding that the Utah Commission has previously allowed**
482 **the Company to recover its prudent hedging costs?**

483 A. Yes. In *Re PacifiCorp, dba Utah Power and Light Company*, Docket No. 01-035-
484 01 (September 10, 2001), the Commission allowed the Company to recover
485 “prudent hedging and arbitrage transactions.”

486 **Q. Does the NRRI Report provide guidance to the Commission on determining**
487 **the prudence of a utility’s hedging costs?**

488 A. Yes. The NRRI Report states that “Second-guessing and micromanaging should
489 be avoided.” It explains that “Second-guessing is contrary to the traditional
490 prudence standard, and in addition, creates distorted incentives for utility
491 hedging.” Instead, it recommends that, “[a]ccording to the prudence standard, a
492 commission should maintain authority to evaluate the reasonableness of (1) a
493 hedging strategy *ex ante*, and (2) the execution of the strategy.” The NRRI
494 Report suggests that a Commission could set an *ex ante* standard by, for example,
495 defining an acceptable level of price volatility.

⁷ Docket No. 09-035-21, Gas Hedging Presentation to The Public Service Commission of Utah Technical Conference, Ken Costello, The National Regulatory Research Institute (June 3, 2009).

496 **Q. Does the Company agree with the NRRI Report’s recommended approach to**
497 **Commission review of the prudence of the Company’s hedging program?**

498 A. Yes. First, throughout the ECAM docket, the Company welcomed guidance from
499 the Commission on the Company’s approach to hedging (but disagreed that the
500 ECAM approval should be contingent on the issuance of such guidance). The
501 Company continues to welcome *ex ante* direction from the Commission on the
502 Company’s hedging program. The Company is supportive of many of the
503 processes suggested by the intervenors for additional Commission review and
504 oversight.

505 Second, the Company agrees that adjustments second-guessing the
506 Company’s hedging program are contrary to the prudence standard. This is
507 especially true given the fact that the intervenors in this case second-guess the
508 hedging program based upon a single year of net losses and/or a subset of the
509 Company’s hedges—and fail to consider the net benefits to customers of the
510 hedging program on a multi-year, all-in basis.

511 **Q. Using the NRRI Report’s approach, how should the Commission review the**
512 **hedging issues in this case?**

513 A. The Company recommends that the Commission first review whether the
514 Company was in compliance with its established risk management policy and
515 hedging program.

516 Second, the Commission should review the Company’s current hedging
517 policy to determine whether the Company should change its policy prospectively.

518 **Q. Do any of the intervenor adjustments challenge the Company's execution of**
519 **its hedging program?**

520 A. No. All of the adjustments challenge the Company's underlying policy guidelines,
521 not the Company's adherence to these guidelines. The evidence is undisputed that
522 the Company transacted its hedges in accordance with its policies. For this reason,
523 the Company recommends that the Commission reject all proposals for
524 disallowance of hedging costs. To the extent that the Commission agrees with
525 intervenors that the Company's hedging program should be revised in some
526 manner, the Commission should order these changes to take effect on a forward-
527 looking basis only.

528 **Overall Response to Hedging Adjustments**

529 **Q. Please summarize the intervenors' hedging adjustments.**

530 A. While the intervenors calculate their adjustments differently, they each seek to
531 disallow a large amount of the Company's hedging losses in the test period. A
532 common set of incorrect assumptions and facts provide the foundation for these
533 adjustments, including:

534 (1) that the Company's hedging program has increased net power costs during
535 its duration;

536 (2) that the Company hedged too much of its open position, compared to other
537 utilities;

538 (3) that the Company hedged over too long a time horizon, given the lack of
539 liquidity in the forward markets (between 36 and 48 months);

540 (4) that the Company failed to adjust its hedging program to respond to

541 foreseeable changes in the natural gas markets; and
542 (5) that the Company should have used options on swap contracts, in addition
543 to or instead of natural gas swaps as a hedging instrument.

544 I correct the record on each of these issues below.

545 **Q. Is there another threshold issue raised by the intervenor adjustments?**

546 A. Yes. To some extent, each of the intervenors attempts to isolate the Company's
547 natural gas swaps from other aspects of the Company's hedging program. It is
548 inappropriate and unfair to propose to disallow gas swaps in isolation when the
549 Company has an integrated hedging program designed to take full advantage of
550 the natural offsets between its long power and short natural gas positions.

551 Power and natural gas are correlated and the positions for each commodity
552 are inextricably linked to spark spreads. As the power and natural gas commodity
553 prices are highly-interrelated, it is appropriate and necessary to report and manage
554 the risk exposures from these commodities in a combined fashion. Separate
555 management of these commodities increases the risk of over hedging or increases
556 the overall risk profile of the Company by hedging in a manner that ignores or
557 reduces natural offsetting positions. A hedging program that ignores this
558 correlation and relationship will naturally be less effective than the current
559 program. This is further demonstrated in the Company's recent 2011 IRP
560 discussion on appropriate hedging strategies.

561 **Q. Are the intervenors' attempts to isolate natural gas hedges from other parts**
562 **of the Company's integrated hedging program problematic from a policy**
563 **prospective?**

564 A. Yes, In the ECAM docket, the DPU and OCS supported rehearing on the
565 inclusion of swaps in the EBA. The DPU argued that including some net power
566 costs and not others in the EBA could create perverse incentives—including
567 leading “the Company to abandon, or lessen, its interest in swaps as a method to
568 control net power costs.”⁸ The hedging adjustments proposed in this case by
569 DPU and others—which allow recovery of some hedges and not others—will
570 raise the same set of issues.

571 **Q. Did the hedging program incur losses for the test period?**

572 A. Yes. As Mr. Apperson discusses in his testimony, the updated net power costs in
573 the Company's rebuttal filing reflect approximately \$83 million of hedging
574 forecast losses.

575 **Q. Why did the Company incur these forecast losses?**

576 A. The forecast hedging losses in the test period are a function of unforeseen
577 declining prices, not the volume of the hedges, the time horizon of the hedges or
578 the hedging instruments used. Hedging protects customers from the risk that net
579 power costs in rates could be significantly higher if prices moved unfavorably in
580 the test period that is used to set rates. To get this protection, customers must give
581 up potentially lower net power costs that could result if prices moved favorably in
582 the test period.

⁸ *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, Response of the Division of Public Utilities to Rocky Mountain Power's Request for Clarification and Reconsideration or Rehearing at 3 (May 2, 2011).

583 **Effectiveness of the Company's Hedging Program**

584 **Q. Should the Commission judge the effectiveness of the hedging program on**
585 **the basis of whether it has made or lost money for customers?**

586 A. No. The goal of the hedging program is to reduce volatility in the Company's net
587 power costs primarily due to changes in market prices. Mr. Duvall demonstrates
588 that the Company's hedging program has significantly reduced net power cost
589 volatility and net power costs.

590 **Q. Please respond to the claim from OCS that the Company's hedging program**
591 **did not reduce volatility.**

592 A. Mr. Duvall addresses this issue. His analysis confirms that the Company's hedges
593 reduce net power cost volatility associated with natural gas and power market
594 price changes.

595 **Q. The DPU, OCS and UIEC all claim that the Company's hedging program**
596 **has significantly increased the Company's net power costs. Is this accurate?**

597 A. No, Messrs. Apperson and Duvall provide more complete evidence on the overall
598 results of the hedging program, which are favorable to customers. As Mr. Duvall
599 testifies, from March 2005, when rates from Docket 04-035-42 went into effect
600 through the end of September 2011 when rates from this case become effective,
601 customers will have received \$149 million in lower net power costs as a result of
602 the Company's hedging program. The customer savings from the hedges now in
603 rates through September 2011 are \$192 million, more than twice the hedging
604 losses reflected in this case.

605 **Q. Why are the Company's results so different than the DPU's?**

606 A. As Mr. Apperson explains, the DPU looks only at natural gas and power swaps,
607 and excludes forward contracts (*i.e.*, fixed price physical power and natural gas
608 transactions). In addition, in comparing the Company's hedged natural gas costs
609 to market, the DPU looks only at natural gas prices, not net energy prices after
610 considering the Company's power swaps and other hedges. The DPU's analysis is
611 incomplete and misleading.

612 **Q. Does UIEC's analysis have the same flaw?**

613 A. Yes. As Mr. Apperson demonstrates, UIEC's assessment of the hedging program
614 is focused only on natural gas swaps and fails to consider the power swaps and
615 other hedging instruments which offset the losses on the natural gas swaps.

616 **Q. What is the problem with OCS's analysis?**

617 A. OCS looks at one year of the Company's hedging results, simplistically showing
618 net power costs and rates, with and without the Company's financial swaps
619 transactions. As Mr. Apperson and Mr. Duvall demonstrate, a multiple-year
620 review of the Company's complete hedging program shows that its results are
621 favorable to the Company and its customers. It is clear that the Company's hedge
622 program has achieved the goal of mitigating net power cost volatility and
623 protecting customers from the risk of adverse price movement.

624 **Q. Is there another problem with the DPU's analysis?**

625 A. Yes. In Mr. Wheelwright's testimony in the 2009 GRC, he was clear that: "It
626 should be understood that there will be periods when the cost exceeds the benefit
627 and periods when benefits exceed costs. Any review or cost benefit analysis

628 should be conducted over an extended period of time.”⁹

629 Mr. Wheelwright omits this statement from his testimony in this docket,
630 and alleges that the Company was imprudent for failing to respond to emerging
631 developments, including “the recent increase in shale gas production, changes in
632 the availability of electric sales and a projected low price for natural gas.” While
633 Mr. Wheelwright previously advocated a long-term view, his adjustment in this
634 case is expressly based upon only “recent” developments.

635 **Q. Mr. Wheelwright claims that the Company’s hedging program is designed**
636 **for an environment of increasing natural gas prices and is no longer**
637 **appropriate because of the decrease in gas prices. Please comment.**

638 A. Mr. Wheelwright relies upon Chart 1 in his testimony to support this point. This
639 chart does not show decreasing natural gas prices. It shows continued increases in
640 natural gas prices, albeit on a more gradual slope. The continued changes in the
641 natural gas price forward markets and third party forecasts over the past several
642 years demonstrate that natural gas markets continue to be volatile.

643 **Hedging Volumes**

644 **Q. Please respond to the claims of intervenors that the Company is hedged at**
645 **too high a percentage compared to other utilities.**

646 A. The Company’s hedging program progresses at gradually increasing levels
647 approaching the time of delivery. This graduated approach provides diversity and
648 flexibility to the hedging program. At the time of delivery, the Company is
649 generally █████ percent hedged. This limits the Company’s exposure to the
650 volatility of the spot market. By the end of the fourth year on a rolling basis the

⁹ Docket No. 09-035-23, DPU Exhibit 12.0 at 2, Mr. Wheelwright (Oct 8, 2009).

651 Company is [REDACTED], (following the expiration of the 15-year
652 Hermiston natural gas supply hedge in July 2011). The progressive hedging from
653 [REDACTED] percent at the time of delivery to [REDACTED] by the end of the fourth year provides
654 the risk diversification benefits of dollar cost averaging during this rolling four
655 year period and avoids concentrated exposure to short periods of price changes.

656 **Q. Do parties such as the DPU overlook the graduated nature of the Company's**
657 **hedging program and overstate the hedged volumes?**

658 A. Yes. Mr. Wheelwright testifies that: "Under the current program the Company
659 will begin to purchase natural gas swap transactions up to [REDACTED] months in advance
660 with the goal of having up to [REDACTED] percent of the forecast gas requirement in place
661 [REDACTED] months in advance." This testimony is inaccurate as shown in the TEVaR
662 table in Highly Confidential Exhibit RMP____(SAB-4R). The Company's hedge
663 program only provides the potential to be [REDACTED] percent hedged in the first rolling 12
664 months.

665 **Q. If the Company had restricted its hedging volumes as proposed by UAE and**
666 **UIEC, would customers have been better off in the past?**

667 A. No. As Mr. Duvall's analysis demonstrates, had the Company imposed the upper
668 limits UAE and UIEC now recommend (75 percent and 66 percent, respectively),
669 customers would have been exposed to higher net power costs and market
670 volatility over the past six years.

671 **Q. Do UAE and UIEC provide sufficient evidence to demonstrate that the**
672 **Company is hedging at imprudent levels?**

673 A. No. To support their claims that the Company is hedged at a higher level than is

674 prudent, both UAE and UIEC provide evidence that a handful of other utilities,
675 including natural gas local distribution companies, hedge at a lower percentage
676 level. UAE points to five other companies, only two of which are in the West, and
677 UIEC reports data from eight companies. Neither UAE nor UIEC make any
678 attempt to determine whether these companies are similarly situated to the
679 Company or have similar risk management policies or hedging programs. Given
680 the fact that several are natural gas distribution companies, it is clear that at least
681 some of the companies are very dissimilar to the Company. None of these
682 companies appear to operate in as large or geographically diverse an area as the
683 Company, where the Company is exposed to the fluctuations of multiple market
684 hubs.

685 **Q. Does UAE's consultant Mr. Fishman warn against looking at industry**
686 **averages to determine appropriate target levels for hedging?**

687 A. Yes. Mr. Fishman acknowledges that "(e)ach hedging strategy is specific and an
688 average may not necessarily reflect an appropriate target." Despite this statement,
689 UAE consultant Mr. Higgins relies upon Mr. Fishman's analysis to recommend
690 an upper boundary for hedging of 75 percent of the Company's natural gas
691 supply.

692 **Q. Does Mr. Fishman's survey show that 75 percent is an upper boundary in the**
693 **electric utility industry?**

694 A. No. Mr. Fishman's survey includes only a small number of natural gas and
695 electric utilities and does not purport to show what the upper boundary of hedging
696 levels is for combined natural gas/power hedging. One of the utilities he reports

697 on, Arizona Public Service Company, reported hedging levels of 85 percent in the
698 year of delivery. Mr. Fishman omitted this data in his survey summary because it
699 was a combined natural gas/power number. Mr. Fishman also reported on
700 Portland General Electric, but failed to note that according to their IRP (excerpted
701 in Mr. Graves' testimony), they hedge their full requirements one year forward. In
702 other words, Mr. Fishman excluded the hedging programs most comparable to the
703 Company's in his results.

704 **Q. Does Mr. Graves provide a broader perspective on these issues?**

705 A. Yes. Mr. Graves has worked with electric utilities for many years and is an expert
706 on electric utility hedging programs. He has access to information about electric
707 industry standards on this issue, which is otherwise difficult to obtain given the
708 confidential nature of the underlying data. Mr. Graves' expert testimony is that
709 electric companies with combined natural gas/power hedging programs hedge at
710 higher volume levels than natural gas-only companies (which rely heavily upon
711 gas storage) and that the Company's program, including its hedging volumes,
712 comports with industry standards. As Mr. Graves testifies, the degree of hedging
713 boils down to a subjective judgment of risk tolerance, and there is certainly
714 nothing objectively imprudent about the extent of the Company's hedging
715 program.

716 **Hedge Horizon**

717 **Q. Do you agree with Dr. Lori Schell's testimony that the Company should**
718 **restrict hedging to up to 36 months?**

719 A. No. The hedge program is based on the premise of hedging forward as long as

720 there is sufficient liquidity. Mr. Apperson demonstrates the liquidity of the market
721 in the period 36 to 48 months from delivery.

722 **Q. Has the Company reduced the amount of its hedges in year four in response**
723 **to current conditions in the natural gas markets?**

724 A. Yes, as noted above, the Company's longer-dated hedge activity, i.e., four years
725 forward on a rolling basis, has decreased by approximately █ percent between
726 2008 and 2011.

727 **Q. Does Mr. Graves provide expert testimony on this issue?**

728 A. Yes. Mr. Graves testifies that hedging over a 36 to 48 month period is a
729 reasonable and prudent practice, especially for an electric utility such as the
730 Company.

731 **Q. Do the results of the Mr. Fishman's survey, limited as it is, show that other**
732 **utilities hedge past 36 months?**

733 A. Yes. Mr. Fishman reported that both Northwest Natural and Portland General
734 Electric hedge over a 5-year horizon.

735 **Q. Did UIEC witness Mr. Mark Widmer claim in a recent Wyoming rate case**
736 **that the Company was imprudent for not having hedged more of its gas**
737 **supply on a long-term basis?**

738 A Yes. In the summer of 2008, on behalf of Wyoming Industrial Energy Consumers
739 ("WIEC"), UIEC witness Mr. Widmer proposed a large adjustment challenging
740 the Company's failure to execute a long-term natural gas supply agreement for its
741 Lake Side plant.¹⁰ In that case, Mr. Widmer argued that the Company should

¹⁰ *In re Application of Rocky Mountain Power to Change Deferred Net Power Costs*, Docket No, 0000-315-EP-08, Deposition of Mark Widmer at 64-66, 87-89(July 15, 2008).

742 diversify market price risk by “hedging on a near term and intermediate and a
743 long-term basis as opposed to doing everything on a near term basis.” Mr.
744 Widmer advocated long-term hedging as a means of prudently protecting
745 customers from inevitable price increases farther out the curve.

746 He also commented that: (1) while he understood that the Company had
747 moved to a longer hedge horizon, “it was still nowhere near where it needs to be;”
748 (2) a review of other utilities’ hedges (like that conducted by fellow UIEC witness
749 Mr. Malko) “was not really relevant;” (3) the Company “has had great experience
750 in terms of controlling costs relative to longer-term hedging;” and (4) “given
751 everything that’s going on in the environment surrounding the price of oil and
752 gas, it just doesn’t make any sense to continue with an approach of hedging costs
753 on a near term, rolling forward basis.”

754 **Q. Did Mr. Widmer propose this adjustment during the time period in which**
755 **the Company acquired some of the hedges in the test period in the case?**

756 A. Yes. This adjustment was proposed in 2008, when natural gas spot prices were
757 high forecast to remain so. Under the Company’s official price curve for June
758 2008, average natural gas prices through June 2012 were \$10.73/MMBtu at Henry
759 Hub and \$9.23/MMBtu at RockOpal. Under these market circumstances, the
760 Company was being criticized by Mr. Widmer for not hedging more, in contrast
761 to this case, where Mr. Widmer supports UIEC’s opposite, hindsight-informed
762 conclusion.

763 **Foresight of Falling Natural Gas Prices**

764 **Q. During the period when the Company was executing hedges 36 to 48 months**
765 **in advance for the test period, should the Company have foreseen the**
766 **decrease in natural gas prices for the test period in this case?**

767 A. No. As just illustrated, spot natural gas prices were very high during this time
768 period. Mr. Apperson shows that neither the forward price curves at the time the
769 hedges were transacted, nor third party spot price forecasts indicated a significant
770 expected future drop in natural gas prices. Mr. Apperson also shows that if natural
771 gas prices had remained high as then reflected in forward market prices or even
772 higher as then forecast by PIRA, the Company's hedges in the test period,
773 especially those in the 36 to 48 month category, would have been deep in the
774 money.

775 **Use of Options**

776 **Q. As an alternative to the Company's traditional practice of using swaps for its**
777 **hedging program, the OCS proposes that the Company use Henry Hub**
778 **natural gas options. Is this appropriate?**

779 A. No. Mr. Apperson analyzes this proposal in detail and demonstrates its many
780 problems, including the fact that it uses a single hedge instrument for the
781 Company's natural gas and power exposures derived from a market (Louisiana)
782 that is remote from the Company's operations. This approach is clearly out of step
783 with current electric industry best practices for hedging, which generally employ
784 more locationally appropriate, liquid and transparent gas and electric swaps to
785 comprehensively and flexibly cover market exposures.

786 **Q. Should the Company include options in its hedging program?**

787 A. There may well be instances when options should be a viable and economic part
788 of the Company's portfolio. Indeed, the Company has used options on a limited
789 basis previously, such as the Morgan Stanley electricity call option contracts
790 reflected in the net power costs in the test period in this case. Before relying upon
791 options on a larger scale as a part of the Company's hedging program, however,
792 an analysis must be made regarding liquidity, basis risk and economics compared
793 to alternatives. In the ECAM docket, the Company proposed a "carefully staged
794 approach" to the broader use of options. This contemplated hedging a small
795 portion of the hedging portfolio initially with options, while working with the
796 Commission and other parties to review the results and address associated issues,
797 including cost recovery of premiums from options that were never exercised.

798 **Q. Have parties questioned the Company's past use of options by challenging**
799 **the recovery of option premiums in rates?**

800 A. Yes. The most immediate example is in this case, where UIEC witness Mr.
801 Widmer recommends that the Commission disallow the option premiums
802 associated with the Morgan Stanley call option contracts. The DPU makes the
803 same proposal in the testimony of Mr. Evans.

804 In the Company's 2007 general rate case, Docket No. 07-035-93, OCS's
805 witness Mr Falkenberg proposed similar adjustments. In the Company's 2010
806 Wyoming general rate case, Docket No. 20000-384-ER-10, both Messrs.
807 Falkenberg and Widmer also proposed the same adjustment for WIEC. The
808 Company disagrees with these adjustments. Nevertheless, in the face of such

809 adjustments, the Company cannot reasonably be expected to have implemented a
810 hedging strategy based solely upon option contracts, as OCS now advocates.

811 **Conclusion on Hedging**

812 **Q. Please summarize your rebuttal testimony on the intervenors' hedging**
813 **adjustments.**

814 A. The Company respectfully requests that the Commission allow full recovery of
815 the Company's forecast hedging costs in this case. There is no dispute that these
816 costs were incurred in compliance within a well-defined risk management and
817 hedging program. When measured on a multi-year, all-in basis, the Company's
818 hedge program has reduced the volatility of net power costs in rates and provided
819 significant benefits to customers. There is no basis for a prudence disallowance
820 simply because hedges increase net power costs in this case. Nor is there any
821 basis for a prudence disallowance because the Company hedged too much,
822 hedged too far forward, or used the wrong hedging instruments. The premise of
823 each of these arguments is that the Company should have predicted in 2007-2009
824 that gas prices would decrease for the test period. This premise is undermined by
825 the evidence of actual market forward price curves and third party spot price
826 forecasts during the time that the Company transacted the hedges in this case.
827 Although the Company believes its current risk management policy and hedge
828 program reflect industry best practices and reasonable risk tolerances, the
829 Company welcomes Commission feedback particularly in regard to going forward
830 risk tolerances, any other aspect of the Company's risk management policy and
831 hedge program, and any type of reporting that the Commission may desire.

832 **Section III Apex Termination**

833 **Q. Do you have anything to add to Mr. Duvall’s rebuttal testimony in response**
834 **Mr. Petersen’s proposal to penalize the Company for terminating**
835 **negotiations to acquire Apex?**

836 A. Yes. As explained more fully in my rebuttal testimony in Docket No. 10-035-126,
837 also incorporated herein by the DPU, the Company made the decision to
838 terminate negotiations for the Apex facility after a comprehensive and thorough
839 due diligence process and economic evaluation. The Company has demonstrated
840 that the termination of negotiations with LS Power was a prudent decision that
841 was in customers’ best interest and was not premature as argued by Mr. Peterson.
842 In Docket No. 10-035-126, the Company admitted that modeling errors were
843 made in the course of updating models with the results of due diligence, but also
844 demonstrated that the errors were quickly recognized and corrected. Once the
845 models were updated and the economics considered with all accompanying risks
846 reflecting complete due diligence, it was clear that the decision to terminate was
847 in the best interest of customers.

848 Mr. Duvall’s rebuttal testimony in this case resummarizes the many
849 reasons why the decision to terminate was prudent and why the DPU’s proposal is
850 unfounded, inconsistent with the approved evaluation process and violates
851 appropriate ratemaking. Nonetheless, the Company recognizes lessons learned
852 from the RFP and proposes to address the process concerns raised by the DPU
853 and the IE by holding a stakeholder workshop in advance of the issuance of the
854 next RFP to consider process improvements and revisit the approved evaluation

855 process to assess and implement improvements to address more unique
856 opportunities like Apex.

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

858 A. Yes.