

Rocky Mountain Power
Docket No. 10-035-124
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Revenue Requirement Surrebuttal Testimony of Chad A. Teply

Environmental Controls Investments

July 2011

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

2 A. My name is Chad A. Teply. My business address is 1407 West North Temple,
3 Suite 210, Salt Lake City, Utah.

4 **Q. Are you the same Chad A. Teply who has previously filed testimony in this**
5 **proceeding?**

6 A. Yes.

7 **Q. What is the purpose of your surrebuttal testimony in this proceeding?**

8 A. My surrebuttal testimony provides additional information explaining the prudence
9 of individual pollution control projects called into question by the intervening
10 parties. In doing so, my testimony will respond to the rebuttal testimony of Mr.
11 Howard Gebhart on behalf of Utah Association of Energy Users Intervention
12 Group (UAE) and Mr. Matthew Croft on behalf of the Utah Division of Public
13 Utilities (DPU).

14 My surrebuttal also includes a correction to a reference made in my
15 rebuttal testimony regarding a revenue adjustment recommended by Mr. Kevin C.
16 Higgins regarding the Dave Johnston Unit 3 scrubber and baghouse project.

17 **Summary of Parties' Concerns and Recommendations**

18 **Q. Please summarize Mr. Gebhart's rebuttal testimony regarding the**
19 **Company's pollution control equipment investments.**

20 A. Mr. Gebhart's primary conclusions in his rebuttal testimony are that the Company
21 has "overshot the mark" in designing and implementing emissions control
22 projects at its Hunter Units 1 and 2, Huntington Unit 1, and Dave Johnston Unit 3.
23 Mr. Gebhart's primary arguments are that the costs associated with said emissions

24 control projects are excessive based on his representation of “standard regulatory
25 practice” as it pertains to determining cost-effectiveness and estimating emission
26 reductions.

27 **Q. Please summarize Mr. Croft’s rebuttal testimony regarding the Company’s**
28 **pollution control equipment investments.**

29 A. Mr. Croft’s rebuttal testimony provides his analyses of the various methodologies
30 that have been discussed in the testimony, exhibits, and extensive discovery
31 presented in this case with respect to establishing cost per ton of pollutant
32 removed and ultimately cost-effectiveness criteria to be applied to the scrubber
33 projects disputed by Mr. Gebhart. Mr. Croft discusses other cost-effectiveness
34 considerations, including fuel quality and equipment end-of-life factors that also
35 significantly impact cost-effectiveness determinations and scope definition for
36 specific projects. Although, Mr. Croft states that the DPU is unable to determine
37 whether the disputed scrubber projects are cost effective at this time; he does cite
38 specific agency determinations that further demonstrate the wide range of costs
39 that states have deemed acceptable via BART determinations, as well as the
40 latitude that states and the EPA have in setting the cost-effective standards that
41 they apply under the Regional Haze Rules.

42 **Cost Effectiveness**

43 **Q. Mr. Gebhart focuses a significant amount of his testimony disputing that the**
44 **Company's response to DPU 36.5 provides a satisfactory basis on which to**
45 **judge the cost-effectiveness of the pollution control investments included in**
46 **this case. Was the Company's response to DPU 36.5 intended to form the**
47 **entire basis of its cost-effectiveness evaluation for the projects in question?**

48 A. No. Rather, the Company's response to DPU 36.5 was intended to be responsive
49 to the question posed by the DPU by comparing the cost per ton of SO₂ emissions
50 at historic permit emission limits versus new permit emission limits. While this
51 cost-effectiveness calculation may be appropriate for units that have historically
52 operated at or near their permitted emission limits and with no forecasted fuel
53 quality changes, it does not provide an appropriate result for the subject Hunter
54 and Huntington units. Those units have historically operated below their 0.21
55 pound per million British thermal unit (Btu) emission limit due to low levels of
56 sulfur in their fuel supplies, and the additional requirement that their scrubbers
57 must remove a minimum of 80 percent of the SO₂ produced when burning the fuel
58 supplied to the respective units.

59 **Q. Are there other considerations that must be made when evaluating the cost-**
60 **effectiveness of the Hunter Units 1 and 2 and Huntington Unit 1 scrubber**
61 **projects?**

62 A. Yes. As discussed at length in the Company's direct and rebuttal testimony filed
63 in this case, considerations with respect to the Hunter Units 1 and 2 and
64 Huntington Unit 1 scrubber projects include more than meeting specific emission

65 limits. The projects for those units included ensuring that the existing systems
66 could effectively accommodate future fuel quality from the cost competitive coal
67 supply market serving the Company's Utah facilities and also comply with the
68 Company's operating permit and waste disposal obligations. Final project scope
69 development for those projects also resulted in the replacement of certain end-of-
70 life equipment and components, although those benefits are secondary in nature as
71 compared to the aforementioned fuel quality and operating permit compliance
72 considerations. The Company's response to DPU 36.5 demonstrates one approach
73 to calculating environmental compliance cost-effectiveness, but it does not fully
74 assess the impact of fuel quality on the tons of SO₂ removed at the subject Hunter
75 and Huntington units. This approach only assesses the change in the SO₂ emitted.
76 It does not assess the total increase in the tons of SO₂ removed.

77 **Q. Has the Company assessed environmental compliance cost-effectiveness**
78 **including the impact of new emission limits and future coal quality for the**
79 **Hunter Units 1 and 2 and Huntington Unit 1 scrubber projects?**

80 A. Yes. The following table was initially developed in response to DPU Data
81 Request 48.5 and was included in my rebuttal testimony with information only for
82 Hunter Units 1 and 2. For purposes of this discussion, the table has been expanded
83 to include Huntington Unit 1 and updated with fuel quality data conformed to the
84 Company's responses to DPU Data Request 36.3 and UAE Data Request 14.3.
85 The table properly identifies the tons of SO₂ that will be removed by the upgraded
86 scrubbers. The tons removed identified in this table consist of the additional tons
87 removed because of the changes in the SO₂ emission rates for the affected units as

88 well as the additional tons removed due to the increases in the coal sulfur content.
 89 While the increase in coal sulfur content is not anticipated to be as significant at
 90 Huntington Unit 1, it remains an important consideration. The cost-effectiveness
 91 results presented in this table further support the projects.

Table 1

	Hunter 1	Hunter 2	Huntington 1
Unit Megawatt Rating, MWn	430	430	445
Unit Hourly Heat Input, mmBtu/hr	4,750	4,750	4,960
Annual Capacity Factor, percent	90.0%	90.0%	90.0%
Unit Annual Heat Input, mmBtu/yr @ 90% CF	37,551,600	37,551,600	39,211,776
Baseline Coal Btu/lb	11,208	11,208	11,724
Baseline Coal Sulfur, % (historical):	0.5	0.5	0.52
Baseline uncontrolled emission rate, lb/mmBtu	0.892	0.892	0.887
Annual uncontrolled SO ₂ emissions, tons/yr	16,752	16,752	17,392
SO ₂ Baseline Emission Rate, lb/mmBtu	0.16	0.16	0.16
Baseline Emissions, tons/yr	3,004	3,004	3,137
Historic tons SO ₂ removed	13,748	13,748	14,255
Future Coal Btu/lb	11,425	11,425	11,117
Future Coal Sulfur, %	0.767	0.767	0.615
Future Uncontrolled emission rate (lb/mmBtu)	1.343	1.343	1.106
Annual uncontrolled SO ₂ emissions, tons/yr	25,210	25,210	21,692
New Permitted SO ₂ Rate, lb/mmBtu	0.12	0.12	0.12
Future SO ₂ Emissions, tons/yr	2,253	2,253	2,353
Reduction in Future SO ₂ emissions, tons/yr	751	751	784
Future tons SO ₂ removed, tons/yr	22,957	22,957	19,340
Net increase in the tons of SO₂ removed, tons/yr	9,209	9,209	5,085
Annual Cost of Control	9,892,000	8,982,000	7,015,000
Dollar per ton estimate based on tons of SO ₂ removed	\$1,074	\$975	\$1,380

92 **Q. Has the Company significantly overstated the amount of SO₂ controlled in its**
93 **cost-effectiveness assessments?**

94 A. No. In fact, the Company's responses to DPU Data Requests 36.3 and 36.5
95 significantly understate the actual amount of SO₂ controlled by the subject Hunter
96 and Huntington scrubber projects as they do not consider the total tons of SO₂
97 removed under the various scenarios presented. The Company's response to DPU
98 Data Request 36.3 provides two scenarios of SO₂ emissions reductions on a tons
99 per year basis. The first scenario (DPU 36.3, Table 1) provides forecasted tons of
100 SO₂ emissions with the scrubber projects completed versus 2006 baseline
101 emissions, without consideration given to total tons of SO₂ removed from the flue
102 gas. The second scenario (DPU 36.3, Table 2) provides forecasted tons of SO₂
103 emissions increases that would have resulted from coal sulfur content increases
104 had the scrubber projects not been completed versus 2006 baseline emissions,
105 without consideration given to total tons of SO₂ removed from the flue gas. As
106 discussed above, the Company's response to DPU Data Request 36.5 provides the
107 cost per ton of SO₂ emissions at historic permit emission limits versus new permit
108 emission limits, without consideration given to fuel quality changes or total tons
109 of SO₂ removed from the flue gas. Table 1 above appropriately estimates the
110 amount of SO₂ controlled by the respective projects, with consideration given to
111 fuel quality changes and total tons of SO₂ removed from the flue gas. Mr. Gebhart
112 has continually failed to recognize fuel quality in his cost-effectiveness
113 calculations and assessments of the Company's Hunter and Huntington units
114 included in this case.

115 **Q. Does the EPA recognize the importance of considering potential fuel quality**
116 **changes in cost-effectiveness assessments?**

117 A. Yes. As documented by the EPA in the Federal Register (Vol. 76, No. 55, March
118 22, 2011, pages 16182-16183) with respect to their review of the state of
119 Oklahoma Regional Haze State Implementation Plan, EPA recognizes the impact
120 that fuel quality has in assessing emission controls and cost effectiveness:

121 “...Although our TSD provides a detailed comparison between the costing
122 methodologies, a few general points can be made that explain why our
123 costs differ with those from ODEQ. First, in the case of the OG&E
124 analyses, a coal with a significantly higher sulfur content than is currently
125 burned was assumed by OG&E’s contractor in determining the design of
126 the scrubber. This increased the capital cost of the scrubber over what
127 would minimally be needed to scrub the coal currently being burned.
128 However, the increased tonnage of SO₂ that would have been removed
129 from the emissions resulting from the burning of that coal, and the high
130 efficiency of the scrubber was not used in calculating the cost
131 effectiveness (\$/ ton). Our cost analysis, assumed the same higher sulfur
132 coal, but adjusted the cost effectiveness to account for the increased
133 scrubber efficiency and the increased tonnage of sulfur that would be
134 removed...”

135 **Q. Mr. Gebhart references the Company’s responses to DPU Data Requests 36.3**
136 **and 36.10 as evidence that the Company’s response to DPU Data Request**
137 **36.5 overstated past actual emissions, and further that the Company is**
138 **attempting to claim credit for controlling SO₂ emissions that were never**
139 **really emitted. Is the Company attempting to claim credit for controlling SO₂**
140 **emissions that were never really emitted?**

141 A. No. The information presented in Table 1 above and the Company’s responses to
142 DPU Data Requests 36.3 and 36.10 claims credit for removing the increased tons
143 of SO₂ that would have been required to be removed from the emissions of the
144 subject units as a result of burning coal with increased sulfur content. As

145 described above, this approach is aligned with the EPA's assessment of similar
146 situations as well as published guidance related to cost-effectiveness
147 determinations. It is important to reiterate, however, that the tons of SO₂
148 controlled are understated in the Company's response to 36.3 as a result of the
149 methodology used to respond to the question posed. As discussed above, the
150 Company's response to DPU Data Request 36.5 was also intended to be
151 responsive to the question posed, but does not fully assess the environmental
152 compliance cost-effectiveness of the Hunter Units 1 and 2 and Huntington Unit 1
153 scrubber projects. The Company recognizes that an accurate environmental
154 compliance cost-effectiveness assessment must properly evaluate the SO₂
155 emissions controlled by a change in permitted emission limits as well as the
156 additional SO₂ removed due to changes in the fuel quality. Additionally, it is
157 important to note that the data included in the Company's responses to DPU Data
158 Requests 36.3 and 36.10 is aligned with and supports the information presented in
159 Table 1 above.

160 **Q. Did the SO₂ reductions identified by the Utah Division of Air Quality and**
161 **included in Utah's Regional Haze State Implementation Plan (SIP) consider**
162 **impacts associated with forecasted fuel quality changes?**

163 A. No. The Utah Regional Haze SIP simply took the SO₂ emissions from their
164 developed historic baseline and compared them to a projection of future emissions
165 for each unit. This approach does not consider the additional tons of SO₂ that
166 must be removed due to increases in coal sulfur content.

167 **Q. Is it appropriate for Mr. Gebhart to rely on the SO₂ emissions control**
168 **benefits quoted in the Utah Regional Haze SIP as the basis for his cost-**
169 **effectiveness analyses?**

170 A. No. The SO₂ emissions control benefits referenced in the Utah Regional Haze SIP
171 do not account for fuel quality changes and therefore do not form an appropriate
172 basis for the cost-effectiveness analyses of the Company's Hunter Units 1 and 2
173 and Huntington Unit 1 scrubber projects.

174 **Q. Has the Company assessed the various cost-effectiveness results that can be**
175 **realized for the Hunter Units 1 and 2 and Huntington Unit 1 scrubber**
176 **projects depending on the fundamental assumptions utilized?**

177 A. Yes. The following Table 2 was initially developed in response to DPU Data
178 Request 48.6. Since the time of initial submittal, the table has been updated to
179 properly reflect the Huntington SO₂ tons removed in the "Wyoming Type
180 Analysis – Increase in Tons SO₂ Removed" line item (second row from the
181 bottom of the table, last column). Table 2 demonstrates the significant difference
182 in cost-effectiveness results when projected coal quality changes are properly
183 incorporated. To ignore this key input, when applicable, is a fatal flaw to any
184 cost-effectiveness analysis. The highlighted rows below are intended to provide a
185 summary of the cost-effectiveness results for the projects that are realized by
186 applying the respective methodologies of the Wyoming and Utah environmental
187 agencies, when properly considering future fuel quality impacts.

Table 2

COMPARISON OF THE DOLLAR PER TON ESTIMATES CALCULATED USING THE TONS OF SO2 REMOVED RATHER THAN THE TONS OF SO2 EMITTED	Hunter 1	Hunter 2	Huntington 1
Annual Cost of Control	\$9,885,000	\$8,982,000	\$7,015,000
Exhibit 36.5 - Change in Tons of SO ₂ Emitted/Removed Based on Higher Sulfur Coal in Baseline, Tons/yr	1,690	1,690	1,765
Exhibit 36.5 - \$/ton Calculation Based on the Change in the Tons of SO ₂ Emitted due to higher sulfur coal	\$5,850	\$5,315	\$3,976
Utah SIP - Decrease in Tons of SO ₂ Emitted, Tons/yr (refer to Table 6, Utah Regional Haze SIP)	502	240	486
Utah SIP - \$/ton Calculation Based on the Change in the Tons of SO ₂ Emitted	\$19,691	\$37,425	\$14,434
Utah SIP - Increase in Tons of SO ₂ Removed, Tons/yr (Refer to Attachment DPU 48.6 case 4 results)	8,749	10,299	3,566
Utah SIP - \$/ton Calculation Based on the Change in the Tons of SO₂ Removed	\$1,130	\$872	\$1,967
Wyoming Type Analysis - Decrease in Tons of SO ₂ Emitted, Tons/yr (refer to Table 2, Attachment DPU 48.5)	751	751	784
Wyoming Type Analysis - \$/ton Calculation Based on the Change in the Tons of SO ₂ Emitted	\$13,162	\$11,960	\$8,945
Wyoming Type Analysis - Increase in Tons of SO ₂ Removed, Tons/Yr (refer to Table 2, Attachment DPU 48.5)	9,209	9,209	5,054
Wyoming Type Analysis - \$/ton Calculation Based on the Change in the Tons of SO₂ Removed	\$1,073	\$975	\$1,388

188 **Q. Does the Company agree with Mr. Gebhart’s assertion that the data**
 189 **presented in his direct testimony accurately reflects the standard regulatory**
 190 **assessment of the cost-effectiveness for the Company’s pollution control**
 191 **projects?**

192 **A.** No. Mr. Gebhart has failed to incorporate future fuel quality considerations into
 193 his analyses, while as discussed above the EPA specifically recognizes the impact
 194 that fuel quality has and specifically incorporates that impact in its regulatory
 195 assessment of the cost-effectiveness of pollution control projects.

196 **Q. Does the Company agree with Mr. Gebhart's assertion that standard**
197 **regulatory practice is that SO₂ cost-effectiveness in excess of \$2,000 per ton is**
198 **generally not reasonable, and controls with such costs would not be required**
199 **by BART?**

200 A. No. The Company does not agree that there is a standard regulatory practice
201 established regarding agency application of cost-effectiveness criteria. Company
202 witnesses Ms. Cathy S. Woollums, Mr. Richard W. Sprott and myself have
203 submitted testimony to this affect in this docket.

204 Simply stated, \$2,000 per ton is a *general* figure based on pre-2005 data
205 for a *majority of uncontrolled* units and state and federal agencies have
206 demonstrated significant latitude in determining and applying cost-effectiveness
207 criteria for various projects. The units Mr. Gebhart is reviewing are controlled
208 units that require incremental improvements in SO₂ removal efficiencies. Mr.
209 Gebhart has offered no evidence supporting his assertion that respective state and
210 federal agencies would not have found these projects cost-effective under their
211 administration of Regional Haze Rules.

212 **Q. Does the Company agree with Mr. Gebhart's assertion that the Company**
213 **intended to mislead the parties with its reference to removal costs of \$7,500**
214 **per ton having been found to be cost effective by state and federal agencies?**

215 A. No. In the Company's response to DPU Data Request 36.6, the Company was not
216 attempting to defend and/or justify the \$7,500 per ton removed reference, but was
217 rather attempting to demonstrate the wide range of costs that states and the EPA
218 have deemed acceptable, as well as the latitude that states have in setting the cost

219 effectiveness standards that they apply under the Regional Haze Rules. The
220 Company disputes intervening party positions regarding the blanket application of
221 a \$2,000 per ton removed cost-effectiveness criteria.

222 **Q. Does the Company agree with Mr. Gebhart's assertion that considerations**
223 **such as equipment end-of-life, reliability, and performance issues are**
224 **irrelevant to a BART determinations and therefore should carry no weight in**
225 **assessing the cost-effectiveness of major pollution control capital**
226 **investments?**

227 A. No. While BART determinations form a portion of the major pollution control
228 capital investment decision-making process, planning and evaluation of cost-
229 effectiveness of individual projects requires consideration of project specific
230 planning inputs including equipment end-of-life, reliability, and performance, as
231 well as operational compliance, site constraints, commercial viability of potential
232 technology solutions, cost of alternatives, etc.

233 **Q. Did the Company's response to DPU Data Request 36.5 address Dave**
234 **Johnston Unit 3 pollution control investments?**

235 A. No. The Company's response to DPU Data Request 36.5 did not include
236 information pertaining to Dave Johnston Unit 3.

237 **Q. Is Mr. Gebhart correct in his references to the final cost-effectiveness**
238 **determination made by the Wyoming DEQ as it pertains to the Dave**
239 **Johnston Unit 3 scrubber and baghouse project?**

240 A. No. In his rebuttal of Mr. Croft, Mr. Gebhart fails to acknowledge pages 104 and
241 105 of the Wyoming Regional Haze (309(g)) State Implementation Plan dated

242 January 7, 2011 which states:

243 “For control of PM/PM₁₀ emissions, the State of Wyoming
244 requires that PacifiCorp install and operate new full-scale fabric
245 filters on Units 3 and 4 to meet corresponding BART emission
246 limits on a continuous basis. When considering all factors above
247 and beyond the benefits associated with regional haze which
248 include the existing precipitator’s current condition and
249 performance and end of life issues, the ability of the current
250 electrostatic precipitator to meet an EPS BART rate of 0.23
251 lb/MMBtu on a continuous basis and the enhanced mercury
252 removal co-benefits the baghouse provides, the Wyoming Air
253 Quality Division has determined that the costs associated with the
254 installation of a new full-scale fabric filter are reasonable. A full-
255 scale fabric filter is the most stringent PM/PM₁₀ control technology
256 and therefore the Division accepts it as BART. The Division
257 considers the installation and operation of the BART-determined
258 PM/PM₁₀ controls of a new full-scale fabric filter on Unit 3 at
259 Dave Johnston, as recently permitted in Air Quality Permit MD-
260 5098, to meet the requirements of BART.”

261 **Q. Does the Wyoming DEQ Regional Haze SIP supersede and take precedence**
262 **over the Wyoming DEQ BART Report AP-6041 referenced by Mr. Gebhart**
263 **in his rebuttal testimony?**

264 A. Yes. The Wyoming DEQ BART Report AP-6041, by its very nature, is a
265 preliminary evaluation performed by the Wyoming DEQ in the early stages of the
266 BART determination process. The Wyoming DEQ Regional Haze SIP dated
267 January 2011, on the other hand, is the Wyoming DEQ’s final determination
268 made after considering all available information, including that developed after
269 the Wyoming DEQ BART Report AP-6041 was prepared. The Wyoming DEQ
270 Regional Haze SIP supersedes and takes legal precedence over the Wyoming
271 DEQ BART Application Analysis AP-6041 dated May 2009.

272 **Q. Was the Wyoming Public Service Commission opposed to the Huntington**
273 **Unit 1, Hunter Unit 2, or Dave Johnston Unit 3 pollution control investments**
274 **that Mr. Gebhart recommends for disallowance?**

275 A. No. In fact, since the filing of my direct testimony, the Wyoming Public Service
276 Commission issued a bench decision approving the stipulation of the parties in
277 that case expressly finding that each of those pollution control investments, which
278 are also at issue in this rate case, were prudently incurred and are used and useful.
279 In fact, the Wyoming Public Service Commission decision approving the
280 stipulation of the parties in that case expressly finds that several of the Company's
281 pollution control investments included in this case, beyond those that Mr. Gebhart
282 recommends for disallowance, were prudently incurred and are used and useful.
283 Attached as Exhibit RMP___(CAT-ISR) to this surrebuttal is a true and correct
284 copy of this stipulation, which was approved by the Wyoming Commission at
285 hearing on June 21, 2011.

286 **Q. Did the Wyoming Public Service Commission oppose to the Hunter Unit 1**
287 **pollution control investments that Mr. Gebhart recommends for**
288 **disallowance?**

289 A. No. The Hunter Unit 1 pollution control investments, although fundamentally
290 identical in scope and justification to the Hunter Unit 2 projects included in this
291 case and deemed necessary, prudent, used and useful by the Wyoming Public
292 Service Commission, have not yet been presented to the Wyoming Public Service
293 Commission due to differences in the rate base test periods between the cases.

294 **Coal Quality**

295 **Q. Has the Company provided substantive information in this case regarding**
296 **projected increases in coal sulfur content, particularly with respect to the**
297 **Hunter facility?**

298 A. Yes. The Company's witnesses including Ms. Cindy A. Crane and myself have
299 provided testimony and exhibits providing detailed information regarding
300 projected increases in coal sulfur content at the Hunter facility.

301 **Q. Would the Company have been required to reduce its SO₂ emissions from its**
302 **Hunter Units 1 and 2 and Huntington Unit 1 regardless of the whether coal**
303 **sulfur content was increasing?**

304 A. Yes. As discussed at length throughout the testimony of Company witnesses in
305 this case, the pollution control investments presented in this case are required to
306 comply with existing regulations including Regional Haze Rules and the Regional
307 SO₂ Milestone and Backstop Trading Program developed in alignment with
308 existing federal regulations and administered in Utah and Wyoming, National
309 Ambient Air Quality Standards, New Source Review requirements, state issued
310 construction and operating permits, and state implementation plans. SO₂
311 emissions reductions at the subject Hunter and Huntington units were required
312 notwithstanding forecasted increases in coal sulfur content.

313 **Q. Did the Company become aware of potential increases in coal sulfur content**
314 **from its primary coal supplier for the Hunter facility after negotiations had**
315 **begun with the state of Utah to establish appropriate SO₂ emission limits for**
316 **the Hunter facility?**

317 A. Yes. The Company became aware of potential increases in coal sulfur content
318 from its primary coal supplier for the Hunter facility in February 2007.

319 **Q. Was the Company able to incorporate this new information into its planning**
320 **processes for the subject Hunter facilities?**

321 A. Yes. The Company submitted its initial Notice of Intent (NOI) application to the
322 Utah Division of Air Quality in August 2006 for pollution control equipment
323 projects at the Hunter plant. The application specifically proposed the installation
324 of low NO_x burners on Hunter Units 1, 2, and 3 and the replacement of
325 electrostatic precipitators with fabric filter baghouses on Hunter Units 1 and 2.
326 The NOI application also requested Plantwide Applicability Limits for NO_x, SO₂,
327 and PM. The NOI application for the Hunter plant was revised and resubmitted
328 several times until being submitted in its final form in November 2007, allowing
329 adequate time for detailed project planning and work scope development. The
330 Utah Division of Air Quality issued its Approval Order for the Hunter plant
331 pollution control projects in March 2008.

332 **Q. Did the timing of the Company's identification and evaluation of potential**
333 **coal quality changes preclude the Company from making prudent and timely**
334 **work scope decisions while planning for pollution control projects at its**
335 **Hunter and Huntington facilities?**

336 A. No. As discussed throughout the Company's testimony in this case, major
337 pollution control projects such as those included in this case are extremely
338 complex multi-year endeavors from conceptualization through permitting and
339 execution. It is not uncommon to adjust project plans to accommodate certain
340 design assumptions and identify additional project constraints during detailed
341 reviews and project execution. To ignore issues of this nature would be imprudent
342 and would not provide the best long-term results for the Company's customers.

343 **Q. Does the Company agree with the findings of Mr. Gebhart's statistical**
344 **analyses of the correlation between coal sulfur content and Hunter Unit 2**
345 **emissions?**

346 A. No. Mr. Gebhart's assertions, based on his best-fit linear regression methodology,
347 that coal sulfur content does not directly correlate with SO₂ emissions and that the
348 Hunter Unit 2 scrubber system actually realized improved performance with
349 higher sulfur coal are completely erroneous and demonstrate a fundamental
350 misunderstanding of the effect of numerous plant operating conditions and control
351 parameters on the data plotted. The differences in historical annual SO₂ emissions
352 plotted by Mr. Gebhart are more a function of the operation of the unit's bypass
353 damper and required stack reheat temperature, among other operating conditions,
354 than the ability of the system to meet a specific level of SO₂ removal. The data

355 plotted by Mr. Gebhart was not collected under test conditions or with SO₂
356 emissions being consistently applied as the controlling variable and provides no
357 value in reaching conclusions regarding the correlation between coal sulfur
358 content and Hunter Unit 2 SO₂ emissions.

359 **Q. What is the basis for the Company's analyses of the correlation between coal**
360 **sulfur content and Hunter Unit 2 emissions?**

361 A. The Company's assessment of the ability of the Hunter Unit 2 scrubber and waste
362 handling systems to accommodate higher sulfur coal is based on actual operating
363 experience regarding the capabilities of the operating systems, as well as a
364 detailed understanding of system design parameters. The Company's operating
365 experience is that the Hunter Unit 2 scrubber system did indeed demonstrate the
366 capability to meet the permitted 80 percent SO₂ removal limit as long as the coal
367 sulfur content remained near or below the 0.5 percent to 0.6 percent level.
368 Forecasted coal sulfur content significantly exceeds the 0.5 percent to 0.6 percent
369 level on an annual average basis across the 10-year planning horizon. In addition,
370 new permit limits require approximately 90 percent SO₂ removal as compared to
371 80 percent SO₂ removal; effectively allowing half of the previously permitted SO₂
372 emissions to exit the stack. The current Hunter scrubber and waste handling
373 systems will not be able to accommodate those increases. The correlation between
374 coal sulfur content and Hunter Unit 2 emissions performance under these system
375 design and operating conditions is demonstrable.

376 **Q. Mr. Gebhart focuses a significant amount of his testimony disputing the**
377 **Company's response to DPU 36.3. Was the Company's response to DPU 36.3**
378 **intended to form the entire basis of its projected emission reductions**
379 **associated with the projects in question?**

380 A. No. As discussed above, the Company's response to DPU 36.3 was intended to be
381 responsive to the questions posed and provided SO₂ emission reductions
382 information as compared to 2006 baseline emissions. Table 1 of the Company's
383 response to DPU Data Request 36.3 compares past actual emissions to forecasted
384 tons of SO₂ emissions with the scrubber projects completed, without
385 consideration given to total tons of SO₂ removed from the flue gas. Table 2 of the
386 Company's response to DPU Data Request 36.3 compares past actual emissions
387 to forecasted tons of SO₂ emissions increases that would have resulted from coal
388 sulfur content increases had the scrubber projects not been completed, without
389 consideration given to total tons of SO₂ removed from the flue gas.. The tons of
390 SO₂ removed presented in Table 2 for Hunter Units 1 and 2 and Huntington Unit
391 1 are based on the assumption that the Regional Haze program would have
392 allowed the operation of the affected units at their historic permit limit of 0.21 lb
393 SO₂/mmBtu. The Company clearly stated in its response to DPU Data Request
394 36.3, that several unrealistic assumptions were made to provide the Table 2 data,
395 including:

396 (1) The Regional Haze program, EPA, and the state of Utah would find it
397 acceptable to increase annual SO₂ emissions above the historic emissions
398 at these facilities.

399 (2) Existing control equipment would not require significant capacity
400 upgrades in order to achieve the required 86 percent removal rate that
401 would be required in order to meet the historic permit limit of 0.21 pounds
402 per million Btu with increasing coal sulfur content.

403 (3) Upgrades and/or equipment replacements in the reagent preparation or
404 waste handling systems would not be otherwise required.

405 While the tons of SO₂ removed information provided in Table 1 of the
406 Company's response to DPU Data Request 36.3 does provide an assessment of
407 past actual emissions to forecasted tons of SO₂ emissions with the scrubber
408 projects completed, the data does not take the total tons of SO₂ removed from the
409 flue gas into consideration.

410 **Q. Has the Company provided a summary of the SO₂ tons removed that best**
411 **represent its projected emission reductions associated with the subject**
412 **Hunter and Huntington projects?**

413 A. Yes. The Company has provided a summary in Table 1 above.

414 **Rebuttal Testimony Correction**

415 **Q. Will you please explain your correction to your rebuttal testimony?**

416 A. Yes. On lines 799 through 816 of my rebuttal testimony I discussed a revenue
417 adjustment recommended by Mr. Higgins that I quantified as appearing to reflect
418 disallowance of what would be the capital cost of the entire Dave Johnston Unit 3
419 scrubber and baghouse project, if it were included in this case. Upon further
420 review, I am now aware that Mr. Higgins' recommended revenue adjustment is
421 limited to a presumed baghouse cost of approximately \$78 million, which is

422 significantly overstated when compared to the Company's estimate of
423 approximately \$47 million for that scope of work. Noting that corrected reference,
424 the Company retains its objection to the applicability of any of Mr. Gebhart's and
425 Mr. Higgins' analyses regarding the Dave Johnston Unit 3 scrubber and baghouse
426 project to this docket, disagrees with the conclusions reached, and further objects
427 to the recommended actions.

428 **Summary**

429 **Q. Please provide a summary of your testimony.**

430 A. The Company continues to disagree with Mr. Gebhart's analyses of the cost
431 effectiveness of the Hunter Units 1 and 2 and Huntington Unit 1 scrubber projects
432 and the Dave Johnston Unit 3 baghouse project, all of which he has recommended
433 for disallowance. Mr. Gebhart's analyses of the subject Hunter and Huntington
434 units fails to properly consider a fundamental cost-effectiveness assessment
435 criteria; namely future fuel quality.

436 Mr. Gebhart's analysis of the Dave Johnston Unit 3 project fails to
437 recognize the final determination of the Wyoming DEQ regarding that project as
438 adopted by the Wyoming Regional Haze SIP. Mr. Gebhart also continues to
439 suggest that it is "standard regulatory practice" for agencies to apply a \$2,000 per
440 ton removed cost-effectiveness criteria to such projects, and that considerations
441 such as ongoing compliance with existing operating requirements, fuel supply
442 flexibility, equipment end of life considerations, equipment performance and
443 operational efficiencies, site constraints, commercial viability of potential
444 technology solutions, and cost of alternatives are irrelevant as part of said

445 assessment. Further, while the Company has demonstrated that when fuel quality
446 is appropriately factored into the analyses of these projects, the projects' cost per
447 ton of emissions removed are within the \$2,000 per ton removed threshold often
448 quoted by the parties in this case, the Company maintains that agency discretion
449 regarding cost-effectiveness criteria often significantly exceeds this threshold.

450 The Company's analyses completed to date demonstrate that maintaining
451 the ability to operate the coal-fueled units included in this case by retrofitting
452 them with the pollution control equipment described represents the least-cost
453 option for our customers. This conclusion is further supported by the stipulated
454 finding and recent order of the Wyoming Public Service Commission regarding
455 overlapping pollution control investments between the two cases, and most
456 notably for the Huntington Unit 1, Hunter Unit 2, and Dave Johnston Unit 3
457 projects to which Mr. Gebhart recommends disallowance.

458 **Q. Does this conclude your surrebuttal testimony?**

459 A. Yes.