BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Utility Service Schedules and Electric Service Regulations	))))))))))	**DOCKET NO. 10-035-124** **Exhibit No. DPU 7.0R-RR** **Rebuttal Revenue Requirement Testimony and Exhibits** **Matthew Croft**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Rebuttal Revenue Requirement Testimony of

Matthew Croft

PUBLIC

June 30, 2011

Q. Please state your name and occupation?

A. My name is Matthew Allen Croft. I am employed by the Utah Division of Public Utilities ("Division") as a Utility Analyst.

Q. What is your business address?

A. Heber M. Wells Office Building, 160 East 300 South, Salt Lake City, Utah, 84114.

Q. Are you the same Matthew Croft who provided direct testimony for the Division on the Company's proposed revenue requirement in this case?

A. Yes.

Q. What is the purpose of the testimony that you are now filing?

A. The purpose of this testimony is to explain revisions to my direct testimony, respond briefly to Ms. Ramas' adjustment concerning plant additions and respond to outstanding issues raised in my direct testimony concerning various scrubber projects. I will also comment on the cost effectiveness and scrubber requirement issues raised by UAE witness Mr. Gebhart.

Q. Will you please explain your revision to your direct testimony?

A. Yes. The first revision is to the Bridger and Trapper mine adjustments in my direct testimony. The combined adjustment amounts from the work papers (DPU 7.4D-RR and 7.8D-RR) were not properly transferred to the table on page 3 of my direct testimony or to the JAM. The corrected amounts increase the Company's revenue requirement by approximately $12,000 from what was in my direct testimony. The second revision is with regards to dollars related to two capital addition projects[1] which I removed from the Company's forecast in the "DPU 30" tab in the excel file DPU Exhibit 7.1D-RR to 7.3D-RR. After discussions with the Company it appears these amounts should not be removed. This

[1] The two projects are the "U1 Generator TIL 1292 and Retaining Rings" and the "Mona - Limber - Oquirrh 500/345 kV line Phases 0, I, and II" project. See the "DPU 30" tab in DPU 7.1 to 7.3R-RR

revision adds approximately $9.6 million of plant additions between April 2011 and May 2011. The table below incorporates the revisions discussed above. It should also be noted that the plant additions and retirements, accumulated depreciation, and depreciation expense items in the table below incorporate the Rolled-In factors as opposed to the "JAM Indicator" factors which were originally used in the table on page 3 of my direct testimony[2]. The table below is a revision of the table on page 3 of my direct testimony and represents adjustments to the Company's original filing.

Adjustment Summary	Total Company Adjustment	UT Adjustment	Approx Revenue Requirement Adjustment
Plant Additions and Retirements	(145,982,020)	(58,914,134)	(6,462,449)
Accumulated Depreciation	93,215,500	44,892,933	5,065,800
Depreciation Expense	(4,401,326)	(1,017,093)	(496,021)
Trapper (DPU 7.8) and Bridger (DPU 7.4)	752,834	320,607	36,043
Accumulated Deferred Income Tax Allocation Adjustment			(106,906)
Accumulated Deferred Income Tax Updates			
Reflect IRS Clarification on Bonus Depreciation			TBD by RMP
Reflect Effect of Plant Addition Update above			TBD by RMP
Total Adjustments			(1,963,534)

Q. Does the table above include the plant additions that were not part of the Company's original filing that were mentioned in your direct testimony?

A. Yes. The actual plant additions through March 2011 included four projects that were not part of the original forecast. The Company provided supporting documentation demonstrating the need for these projects and so I have included them in the table above as was done in my

[2] Although the Utah allocated amounts were misstated in the table, the total Company adjustment and approximate revenue requirement amounts were correct (before considering the two projects that I have added back, here in this testimony). The DGP, DGU, SSGCH, SSGCT factors are JAM Indicator factors (used in the "Adjustments" tab of the JAM) which are subsequently changed to SG factors in the JAM under the Rolled-In methodology. The "Factor" column in the "JAM Inputs" tab of the DPU 7.1R-RR to 7.3R-RR has been revised to reflect the SG factor in place of the DGP, DGU, SSGCH and SSGCT factors.

direct testimony. Likewise, there were seven projects[3] in the Company's revised April 2011 to June 2012 forecast that were not part of the original forecast. The Company has also provided supporting documentation related to these projects and they are included in the table above as was done in my direct testimony.

Q. In her direct testimony, OCS witness Ms. Ramas proposes an adjustment to reduce the April 2011 to June 2012 plant additions by 4.3%. She also uses part of your test year testimony as support for her position. Why have you not proposed a similar adjustment?

A. Page 5 of Mr. McDougal's surrebuttal test year testimony demonstrates that previous Company forecasted net electric plant in service (EPIS) balances have actually been under the actual net EPIS balances. My analysis in the test year portion of this docket relied on gross EPIS. I acknowledged this difference at the test year hearing. Since net EPIS is the more true effect on rate base, I have not proposed an adjustment similar to that of Ms. Ramas.

Q. Would you please summarize your understanding of Mr. Gebhart's testimony concerning the Dave Johnston Unit 3 (DJ3) scrubber and baghouse project, Hunter 2 scrubber project, Hunter 1 scrubber project and Huntington 1 scrubber project?

A. Mr. Gebhart found that the Utah projects were not cost effective and that the incremental cost effectiveness for the DJ3 project in Wyoming was not reasonable. He also comes to the conclusion in lines 928 to 930 of his testimony that the three Utah "scrubber upgrade projects provide emissions control that is well beyond the regulatory requirements imposed on the units by current and reasonably anticipated environmental regulations."

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[3] See the "DPU 30" tab of the DPU 7.1R-RR to 7.3R-RR

Q. Would you please address the cost effectiveness issue with regards to the DJ3 project?

A. Yes. With regards to DJ3, Mr. Gebhart bases his cost effectiveness analysis on the same analysis performed by the Wyoming Division of Air Quality ("WDAQ") in their BART Application Analysis[4]. The capital and O&M costs as well as SO2 tons removed in that analysis originated from a March 2008 Addendum[5] analysis performed by CH2MHILL on behalf of PacifiCorp. The WDAQ analysis showed that the incremental cost effectiveness of the "Dry FGD with ESP and Polishing Fabric Filter" option was not reasonable. There has been considerable confusion as to whether or not the "Dry FGD with ESP and Polishing Fabric Filter" listed on page 22 of that analysis is actually what the Company went forward with. As of the time of writing my direct testimony I was under the impression that what was listed on page 22 of that WDEQ analysis was what the Company actually went forward with. It appears based on Mr. Gebhart's testimony that he also assumed that what was listed on page 22 is what the Company chose. The Company however, has essentially said in response to UAE 12.5 that a "Dry FGD with ESP and Polishing Fabric Filter" is not the project that was actually chosen. The Company chose a different option that included a full-scale baghouse as opposed to the polishing baghouse mentioned on page 22 of the WDAQ analysis. My discussions with WDAQ personnel have indicated that at the time of preparing the WDAQ analysis it was not entirely clear which direction the Company was headed. However, upon review of the March 2008 Addendum it was indicated to me by the same personnel that it could be reasonably assumed that the March 2008 Addendum did describe a project with a full-scale fabric filter, the numbers of which were used in WDAQ's analysis.

[4] See DPU Exhibit 7.8R-RR

[5] See DPU Exhibit 7.7R-RR. Page 15 of the PDF file shows the costs of the "Upgraded Dry FGD Fabric Filter" tie to the costs of the "Dry FGD with ESP and Polishing Fabric Filter" option listed on page 22 of the WDAQ analysis (DPU Exhibit 7.8R-RR).

Q. At the end of the day, was the full-scale baghouse project determined to be cost effective by WDAQ?

A. Yes. As was stated in my direct testimony, WDAQ determined in their Wyoming 2011 State Implementation Plan ("WY SIP") that the full-scale fabric filter project for DJ3 was cost effective. Page 104-105 of the WY SIP states:

> For control of PM/PM_{10} emissions, the State of Wyoming requires that PacifiCorp install and operate new full-scale fabric filters on Units 3 and 4 to meet corresponding BART emission limits on a continuous basis. When considering all the factors above and beyond the benefits associated with regional haze which include the existing precipitator's current condition and performance and end of life issues, the ability of the current electrostatic precipitator to meet an ESP BART rate of 0.23 lb/MMBtu on a continuous basis and the enhanced mercury removal co-benefits the baghouse provides, the Wyoming Air Quality Division has determined that the costs associated with the installation of a new full-scale fabric filter are reasonable. A full-scale fabric. filter is the most stringent PM/PM10 control technology and therefore the Division accepts it as BART. The Division considers the installation and operation of the BART-determined PM/PM_{10} controls of a new full-scale fabric filter on Unit 3 at Dave Johnston, as recently permitted in Air Quality Permit MD-5098, to meet the requirements of BART.

Q. Would you please address the cost effectiveness issue with regards to the three Utah scrubber projects?

A. Yes. The table below is a comparison of the cost effectiveness calculations done by the Company[6] and Mr. Gebhart.

<u>Table 1</u>

[6] Company numbers are from the Company's response to DPU 36.5 (DPU 7.6R-RR)

		Hunter 1	Hunter 2	Huntington 1
Gebhart	Annualized Costs	$ 8,176,160	$ 7,426,325	$ 5,797,646
	Tons SO2 Removed	502	240	486
	Cost/Ton SO2 Removed	$ 16,287	$ 30,943	$ 11,929
RMP	Annualized Costs	$ 9,885,329	$ 8,981,512	$ 7,018,376
	Tons SO2 Removed	1,690	1,690	1,765
	Cost/Ton SO2 Removed	$ 5,850	$ 5,315	$ 3,977

Obviously there is a very different opinion on the cost effectiveness of these projects. As can be seen from the table above, the biggest difference is in the tons of SO2 removed. This difference comes as a result of different methodologies used to calculate the SO2 tons.

Q. Would you please explain the different methodologies used to calculate the SO2 tons removed in Mr. Gehart's and the Company's analyis?

A. Yes. In general, the change in SO2 tons are calculated by comparing a "baseline" amount to a "post-control" amount. The tons of SO2 in Gebhart's analysis originated from the 2008 UT SIP. The baseline used in the 2008 UT SIP is based on past actual emissions.[7] The post control amounts are based on projected 2018 actual emissions based on the new permitted rate and a growth factor. The Company's analysis in DPU data request 36.5[8] uses the existing permitted emissions as a baseline and the new permitted emissions as the post control amount.

Q. What do you believe is the more correct method to calculate SO2 tons removed?

A. While there may be certain aspects of Mr. Gebhart's methodology (possibly using actual emissions in a baseline) that have been used in cost effective analysis performed by WDAQ, I have been told by Utah Division of Air Quality ("UDAQ") personnel that the

[7] DPU 44.10 states: The Utah SIP simply took the past actual emissions and compared them to the future potential emissions for each unit. This does not consider future SO_2 increases due to fuel changes. DPU Data Request 36.3 takes into consideration all aspects of unit operation, both historical and projected, to estimate the emissions that would occur with and without the modifications being installed on the Hunter and Huntington units.

[8] See DPU 7.6R-RR

SO2 reductions in the UT SIP were never intended for the purpose of a cost effective analysis and were there for informational purposes only. However, I'm not sure the Company's methodology is right either. The Company stated in response to DPU 44.10 that:

> The baseline emissions in a five factor test are not based on a unit's past actual annual emissions, but on a permitted emission limit that defines a unit's potential emissions. An example of this can be seen in the five-factor tests that have been conducted at Jim Bridger units 1-3. These units were scrubbed to a required 0.3 lb/mmBtu emission rate, and this rate (lb/mmBtu), along with a maximum hourly heat input rate and a 90% capacity factor were used to calculate the baseline tons of SO_2 emitted. Past actual emissions are not used. In the five factor test, the post-upgrade SO_2 emissions are calculated in the same manner, using the new SO_2 emission rate to determine the post project annual emissions. The difference between these two estimated annual emissions represent the tons removed by the upgrade.

I am not sure what the Company means by "five-factor tests that <u>have been conducted</u> at Jim Bridger units 1-3." The cost-effective analysis performed by WDAQ for Jim Bridger Units 1-3 reveals information different than the Company's response to DPU 44.10. WDAQ's analysis used past actual emissions[9] (.27lb/MMBtu[10], 6,386[11] tons) as a baseline. The post control emissions were based on the expected control's design (.10lb/MMbtu, 2,365 tons[12]). WDAQ's analysis yielded an SO2 reduction of 4,021 tons. The cost per ton determined by WDAQ is $620[13]. Interestingly enough WDAQ's cost is actually less than the $1,124[14] cost calculated by the Company in response to DPU 36.5.

Q. Has WDAQ used other methodologies for calculating SO2 tons removed?

[9] Confirmed by WDAQ personnel
[10] See PDF pages 30 and 62 of DPU 7.4R-RR
[11] See PDF page 25 of DPU 7.5R-RR. 6,386 – 2,365 = 4,021 tons
[12] See PDF page 62 of DPU 7.4R-RR and page 25 of DPU 7.5R-RR
[13] See PDF page 25 of DPU 7.5R-RR
[14] Average of the three Jim Bridger units. See DPU 7.6R-RR

A. Yes. WDAQ's analysis for the DJ3 unit used the existing permit rate (1.21lb/MMBtu[15], 13,316 tons) as the baseline and the expected control's design (.15lb/MMBtu[16], 1,656 tons) as the post control emissions.

Q. Are both methodologies discussed above acceptable by WDAQ?

A. Yes.

Q. Has the EPA issued any guidance on how to calculate the baseline SO2 emissions?

A. Yes. The EPA's Proposed Regional Haze Rules published in July of 2001 as well as the current Appendix Y of CFR 51 (IV)(D)(4) use the same language. This language states:

> d. How do I calculate baseline emissions?
>
> 1. The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period.
>
> 2. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.

Appendix Y of CFR 51 (IV) further states:

> f. What other information should I provide in the cost impacts analysis?
>
> You should provide documentation of any unusual circumstances that exist for the source that would lead to cost-effectiveness estimates that would exceed that for recent retrofits. This is especially important in cases where recent retrofits have cost-effectiveness values that are within what has been considered a reasonable range, but your analysis concludes that costs for the source being analyzed are not considered reasonable. (A reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time.)

[15] See PDF page 14 of DPU 7.7R-RR
[16] See PDF page 14 of DPU 7.7R-RR and PDF page 22 of DPU 7.8R-RR

Q. Given this guidance by the EPA, why did WDAQ sometimes use the existing permit limit in its baseline calculations?

A. When asked this question, WDAQ personnel responded by stating the EPA proposed rule is a recommended methodology and that the method used by PacifiCorp (comparing previous limits to the new limits) is more conservative.

Q. Would the Company's methodology be more conservative from an environmental standpoint but not necessarily a cost/per ton perspective?

A. It appears that would be the case. However, the Company cannot obviously meet both. Again, using actual emissions in a baseline has been accepted by WDAQ but using the existing permit limit has also been accepted.

Q. Is it appropriate to consider other factors besides a strict cost/SO2 ton removed when conducting a cost effective analysis?

A. Yes. I believe other factors should be considered when conducting a cost effective analysis. WDAQ considered other factors when conducting their analysis of the DJ3 baghouse project. WDAQ considered other factors such as end of life issues, existing equipment performance, and multiple pollutant benefits. Mr. Gebhart also acknowledges other factors in his analysis of the Dave Johnston Unit 4 scrubber project such as outdated technology and the infeasibility of upgrading existing equipment[17]. Other factors can be a way of supporting a project that otherwise would be considered not cost effective because of a strict cost per ton of SO2 removed. This concept is also supported by the EPA's Proposed Regional Haze Rules issued in July 2001. When refering to cost reasonable ranges for *uncontrolled* plants (Hunter 1, Hunter 2, and Huntington 1 are already controlled at 80%) page 24 states:

[17] UAE Exhibit RR 2.0 page 29.

> We believe that the ''consideration of cost'' factor for source-by-source BART, which is a technology-based approach, generally requires selection of control measures that are within this level of cost effectiveness. We recognize, however, that the population of utility boilers subject to BART may have case-by-case variations (for example, type of fuel used, severe space limitations, and presence of existing control equipment) that could affect the costs of applying retrofit controls.

Q. What other factors should be considered in analyzing the cost effectiveness for the three disputed Utah scrubber projects?

A. Other issues that should be considered in analyzing cost effectiveness for these projects should include end of life issues, existing equipment performance, and the increase in sulfur content that is expected to occur over the next several years. There could be others but these three seem to be the principal factors involved with the three Utah scrubbers.

Q. Is there significant evidence that the Company was aware of end-of-life issues and planned to be resolve them prior to their permit applications for the three Utah scrubber projects?

A. Yes and no. At the time of my direct testimony it appeared, based on the Company's response to UAE 3.4 and DPU 36.11 that there were end-of-life issues. After direct testimony, UAE requested documentation <u>supporting</u> the end-of-life issues claims. DPU 7.10R-RR is a summary of the end-of-life issues claimed by the Company as well as the related supporting documentation. Although detailed cost breakdowns of end-of-life issues were provided as part of UAE 14.11 and UAE 14.13, there was no significant documentation (other than Huntington 1) showing that the Company had previously identified and planned to address these end-of-life issues prior to the permit application for the scrubber. An appropriation request (APR) was provided as showing the need to replace four pumps at

Huntington Unit 1 which were replaced but were not part of the scrubber project. The cost of replacing twelve other pumps were included in the scrubber costs. The evidence for these four and twelve pump replacements previously being contemplated is in the following excerpt from the APR.

PacifiCorp / Scottish Power Expenditure Requisition | Revision Date / Number

Huntington	Unit 01	Start Fiscal Plan Year
Title: [illegible] Replacement		SAP Project Definition: [illegible]
Plan Type: Budgeted		Location Code: [illegible]
Investment Reason: Replace - Thermal		Prepared By: Kendal Yost
Environmental Review: Environmental Review is Pending		Retirement: Yes
Overhaul Related: No		Expense Type: Capital

(What is the project and why are we doing it?)

Replace four of the existing original sixteen scrubber recycle spray pumps. Poor reliability, excessive maintenance costs and poor performance have plagued this system for years. This is the beginning of securing more efficient and reliable recycle spray pumps.

A second APR was provided as evidence for replacement of the recycle pumps at Hunter Unit 2. However the APR was prepared in 2008, long after the commitment (permit/construction application) to the Hunter 2 scrubber project in August 2006. The Company's response to UAE 14.11 also states:

> Other components such as the reagent preparation system, in the 2005 to 2006 time period, had not yet reached a point of replacement, and without the scrubber project would have been candidates for future replacement. However, the documentation process for authorizing funds for replacement was not started prior to scoping the scrubber project.

The Company's revised estimated end-of-life issue costs for the Hunter 1, Hunter 2 and Huntington 1 units is shown in Table 2 below. The costs are from the Company's response to UAE 14.11.

Table 2

End-of-Life Issues Costs for Hunter 1 and Hunter 2

New Recycle Pumps	$4,689,394
25% Nozzle Replacement (not broken out by Contractor)	$400,000
Replace existing absorber agitators	$1,580,787
Lime Preparation System	$17,181,330
Total with full Lime System Cost	$23,851,511
Lime Preparation credit to share costs with higher sulfur Issue	$8,590,665.20
Total Hunter Unit 1 or Hunter Unit 2 End-of-Life Estimate	$15,260,845.76

End-of-Life Issues Cost for Huntington Unit 1

New Recycle Pumps	$1,758,523
25% Nozzle Replacement (not broken out by Contractor)	$200,000
Replace existing absorber agitators	$700,899
Lime Preparation System	$0
Total with full Lime System Cost	$2,659,421

At this point, accepting the majority of these costs would be relying on the Company's after-the-fact analysis, rather than specific supporting documentation that these end-of-life issues were "previously planned to be resolved independently of the scrubber project." I think it is important to note that just because an APR doesn't exist, it doesn't necessarily mean that an end-of-life issue doesn't exist. The issue could have existed but perhaps the documentation to secure the funds for that issue had not yet been started. One might expect the end-of-life issues to show up in the capital budgeting process. In this case however, these end-of-life issues would probably have been rolled into the budget for the scrubber project itself. Acknowledging that there may be reasons for why supporting documentation does not exist, it is difficult to look back now without sufficient documentation and determine that these end-of-life issues did exist, were significant, and were planned to be resolved.

Q. Is there significant evidence that the Company was aware of existing equipment performance and considerable maintenance issues before submitting the scrubber permit application?

A. Yes and no. DPU 7.11R-RR is a summary of the performance and maintenance issues the Company has claimed through data request responses. This document shows maintenance costs associated with just the Hunter 2 unit scrubber. Between 2004 and 2006 approximately $4.4 million (capital and O&M)[18] was spent on maintenance with the existing Hunter 2 scrubber. Other costs were identified for Hunter 2 and Hunter 1 but they were generally after 2006. Although these costs are provided, there is no comparison done to show that they are necessarily high or abnormal. With regards to PacifiCorp's claim in DPU 36.12 that "maintaining three operating pumps per absorber tower had become extremely difficult" at the Huntington and Hunter plants the Company stated:

> Please also refer to the company's response to UAE Data Request 14.11. These pumps are well known by plant personnel to be unreliable as evidenced by the proposed replacement of these pumps at both Huntington Unit 1 and the Hunter plant. Attached, as an example, is a compilation of the Hunter Unit 2 recycle pump recent maintenance history incurred as Confidential Attachment UAE 14.17. Almost all pumps require routine maintenance and what is not shown in attachment is the duration of time each pump was unavailable waiting for the action on the subject work order. These costs were present even though it was known in the later years that the pumps would be replaced in the near future. It was a common occurrence to have two of four pumps on an absorber tower unavailable for service due to equipment malfunction/failure. The scrubber system requires three recycle pumps be in operation to meet the required level of sulfur dioxide removal. This is reiterated in the Marsulex contract Section 3.4.1 of Exhibit A-2, which defines system performance guarantees and states:
>
>> "3.4.1 FGD Performance Guarantees:
>>
>> The Performance Guarantee and Availability Guarantee provided by Contractor are based on the proper operation, maintenance and reliable performance of FGD and balance of plant equipment not replaced or modified within the scope of this Contract. Should the failure or deficient performance of any such equipment and/or systems not modified hereunder be the cause or contribute to failure of any guarantee, such guarantee(s) would be adjusted or rescheduled by mutual agreement. Guarantees may be waived at the sole discretion of the Owner.

[18] Excludes lime costs. With lime costs the amount between 2004 and 2006 would be $5.6 million.

> All performance guarantees are based upon proper operation of existing equipment, piping and instrumentation which has not been replaced within this contract. Should the guarantees be impacted due to failure or abnormal operation of existing equipment guarantees will be adjusted by mutual agreement.
>
> a. SO2 emission shall not exceed 0.10 lb/mmBtu between low load aand 100% MCR boiler load with four absorbers in service and any combination of three (3) recycle pumps operating per absorber for 0.26 to 1.3% sulfur coal content coal.
>
> b. SO2 emission shall not exceed 0.10 lb/mmBtu between low load and 100% MCR boiler load with three absorbers in service and four (4) recycle pumps operating per absorber for 0.26 to 1.3% sulfur content coal.
>
> c. SO2 emission shall not exceed 0.12 lb/mmBtu between low load and 100% MCR boiler load with three absorbers in service and any combination of three (3) recycle pumps operating per absorber for 0.26 to 1.3% sulfur content coal."

The date or effective date of the Marsulx contract is not mentioned, but my understanding is that the .12lb/mmBtu limit and the .10lb/mmBtu limit were a result of the scrubber permitting process and not limits that existed prior to applying for the permit. The Company may prove otherwise, but these contract limits do not appear to be applicable before the permit application for the scrubber projects. There may be some specific supporting documentation for maintenance issues but it is difficult to determine if these maintenance costs were particularly high for the units for which data was provided.

Q. Why is sulfur content a significant issue with regards to the cost effectiveness of the scrubber projects?

A. As discussed previously, tons of SO2 removed is part of the cost effectiveness determination. However, neither the WDAQ methodologies or the SO2 tons removed from the UT SIP take into consideration increases in sulfur content of coal supplies. My conversations with UDAQ personnel have also indicated that sulfur content is an issue that could be considered in doing a cost effective analysis. Also, the Company has reported that increasing sulfur content would create compliance issues associated with waste product delivered to landfills (DPU 36.8[19] and UAE 14.8b[20]), as well as the Hunter 1 and Hunter 2 reagent preparation facility's ability to produce sufficient product at coal sulfur content in excess of 0.6% (DPU 36.8). The Company also states in DPU 36.12 that

> Areas of concern included the high maintenance requirements and reliability issues with the recycle pumps. For the Huntington and Hunter systems, maintaining three operating pumps per absorber tower had become extremely difficult. As long as the coal sulfur content trended at historically low levels at these units, it was possible to maintain compliance with the 0.21 pounds per million Btu SO2 emission limit with only two pumps in service.

Based on the Company's Confidential 1st Supplemental Response to UAE 14.3[21] the sulfur content is expected to increase as shown in the graph below.

[redacted]

Due to the reasons described above I have included the sulfur content issue as an "other" factor for determining cost effectiveness. The scrubber projects not only reduce emissions

[19] See DPU 7.12R-RR.
[20] See DPU 7.13R-RR
[21] See DPU 7.14R-RR

but they also prevent future increases in emissions due to the increase in sulfur. The Company performed an analysis to show what the projected decreases as well as avoided increases would be. The analysis, from UAE data request 14.3 (1st Supplemental) is included in Confidential DPU Exhibits 7.15R-RR, 7.16R-RR and 7.17R-RR and uses 2006 actual emissions as a baseline.[22] The future emissions are based on the Company's actual emission projections. The table below is a summary of that analysis as shown in DPU 36.3.

Table 3

SO2 Emission Reductions(Tons/Yr): Actual Decreases Plus Avoided Increases

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Hunter 1				436	2,010	2,023	2,004	1,788	1,975
Hunter 2	772	1,585	1,927	1,926	1,838	2,000	1,968	1,968	1,786
Huntington 1			1,490	1,300	2,295	1,891	1,545	1,057	1,176

When compared to Table 1 (stated earlier in my testimony), the SO2 tons removed when considering increases in sulfur are generally greater for the Hunter 1 and Hunter 2 units while the Huntington 1 unit is generally a little lower.

Q. Have you completely relied on the Company's claims concerning sulfur content issues?

A. Yes. It appears, based on data requests from UAE that there may be some question as to what the Company did know at the time of commitment to the disputed Utah scrubber projects. There also appears to be questions as to whether blending and or other management of coal supply could have or should have resulted in a different trend in the sulfur content. Neither myself nor Division staff has performed a detailed analysis of these issues. Ideally the Division would want to understand all of the finer details associated with why the sulfur

[22] 2006 was a relatively high year compared to the other years (2000-2005) but it is the year that was used to develop the milestone that are in the 2011 UT SIP.

content is increasing but such a detailed analysis was not possible at this time. Generally speaking however, the Division has been aware since at least 2006 that the Company was facing an increase in coal sulfur content generally.

Q. Will you please summarize your findings with respect to these "other factors"?

A. Acknowledging that there may be reasons for why supporting documentation does not exist, it is difficult to look back now without sufficient documentation and determine that these end-of-life issues did exist, were significant, and were planned to be resolved. A similar situation exists with regards to performance and maintenance issues. The Division has generally been aware of coal sulfur content issues since at least 2006. It appears at this time that the sulfur content issue is the most significant "other factor" to be used to support the Company's belief that the scrubbers are cost effective.

Q. Would you please restate the purpose of considering other factors?

A. The purpose is to consider other support for a project that otherwise would be considered not cost effective on a strict cost per ton of SO2 removed basis.

Q. Assuming that a correct cost per SO2 ton removed could be determined, what benchmark should be used to determine if the projects are cost effective?

A. In my direct testimony on lines 446 to 448 I stated:

> [T]he Company also has shown in DPU 36.6 that recent BART determinations issued by the EPA and other state agencies for SO2 emission control projects have demonstrated that costs of up to $7,500 per ton are not considered cost prohibitive.

The exact statement from DPU 36.6 states:

> Recently, BART determinations issued by the EPA and other state agencies for SO2 and NOx emission control projects have demonstrated that removal costs of up to $7,500 per ton are not considered cost prohibitive.

Since that time, the Company responded to UAE 14.5 by stating:

> Attachment UAE 14.5 provides the BART determination for the San Juan plant where removal costs of up to $7,900 per ton (including annual energy impacts) were deemed acceptable. Although this specific example is related to NO_X emissions and not SO_2, it demonstrates the wide range of costs that states have deemed acceptable as well as the latitude that states have in setting the cost-effective standards that they apply under the regional haze rules. Although the EPA has provided ranges of cost effectiveness for both SO_2 and NO_X, there are numerous examples of states, including New Mexico, Colorado, Wyoming, and Oregon, that have required facilities to install controls that significantly exceed these costs. EPA itself has exceeded their own cost guidelines in making BART determinations for the Four Corners and Navaho Power stations.

It appears the Company may have originally suggested that the $7,500 was related to SO2, but based on UAE 14.5 it now appears that the $7,500 or $7,900 does not relate to SO2 at all. As such the $7,500 used in my direct testimony cannot be used as a benchmark.

Q. Should these accepted NOX costs be applicable to the SO2 scrubbers at Hunter 1, Hunter 2 or Huntington 1?

A. At this time I am not aware of anything that would suggest they should be. In fact, the EPA has established separate cost ranges for SO2 and NOX.

Q. The Company's response to UAE 14.5 suggests that the EPA has exceeded its own cost effectiveness guidelines at various units. What are the EPA's cost effective guidelines relevant to Hunter 1, Hunter 2 and Huntington 1?

A. My understanding is that the EPA has stated a range of cost effectiveness of $400-$2,000 per ton for *uncontrolled* units but has not stated a range for already *controlled* units.

Q. Are the Hunter 1, Hunter 2 and Huntington 1 units already controlled?

A. Yes. As such, the $400 - $2,000 range does not seem to be applicable. One would suspect, that because a unit is already controlled, further controls would likely prove more costly than the $400 - $2,000 range.

Q. What have been the costs of similar scrubber projects on controlled plants?

A. Assuming that the scrubber projects related to the controlled units in the chart on page 9 of Mr. Gebhart's testimony are similar to the Hunter 1, Hunter 2 and Huntington 1 scrubber projects, the range is between $49 and $1,571 per ton of SO2 removed. Mr. Gebhart also mentions in his testimony that the Laramie River Station scrubber project ("Eliminate Stack Reheat System") was determined by WDAQ to not be cost effective. The cost for the Laramie River Station was determined by WDAQ to be $9,542 per ton of SO2 removed. Assuming that his assumption is correct that the Eliminate Stack Reheat System is similar to the disputed Utah scrubber projects, this could be used as as a ceiling for considering cost effectiveness. In other words, costs above $9,542 would for sure not be considered reasonable, but it could be that costs below $9,542 might also not be reasonable. However, it appears based on WDAQ's analysis[23] that the baseline used for the Eliminate Stack Reheat project was based on a three year average of past actual emissions. Since we know that using existing permitted limits in a baseline is accepted in Wyoming, the $9,542 may not be an appropriate ceiling for cost effectiveness. The WDAQ analysis for the Dave Johnston Unit 4[24] determined that $5,028 was cost effective. It should be noted that this project included a baghouse and as such affected multiple pollutants like PM and Mercury and not just SO2. My understanding is the Hunter 1, Hunter 2, and Huntington 1 scrubber projects principally affect SO2 and I am not aware if they materially affect PM although it is listed as a secondary pollutant in the Company's 1st supplemental response to DPU 24.2. Mr. Gebhart agrees with the WDAQ analysis for Dave Johnston Unit 4 especially in light of the existing outdated technology. That same analysis, which relied on a CH2MHILL's analysis, shows

[23] See Table 6, page 14 of DPU 7.18R-RR
[24] See PDF page 23 of DPU 7.8R-RR

that the SO2 removal efficiency increased from 58.6% to 87.6%.[25] Based on Mr.Gebhart's testimony, the SO2 removal efficiency increases from 80% to near 95% for Hunter 1, Hunter 2 and Huntington 1.

Q. When determining that the Eliminate Stack Reheat System cost of Laramie River Station Unit 2 was not cost effective, what benchmark was used by WDAQ?

A. It appears, based on my conversations with WDAQ that there was never really a clear, defined benchmark used, nor do they use one when dealing with other previously controlled units. One of the issues pointed out to me[26] was that the visibility improvements, measured in terms of deciviews was not significant for the other SO2 controls considered at Laramie Station such as "FGD Chemical Additives" and "Sorbent Injection." WDAQ's analysis indicated the resulting .02 deciview improvement from all three units combined was insignificant. It appears that WDAQ considered deciview improvement as an "other factor" when considering the cost effectiveness of these other SO2 related projects.

Q. Based on the information explained to this point, where would a benchmark for cost effectiveness fall?

A. Based on findings of and conversations with WDAQ it appeared to me initially that a benchmark would fall somewhere between $2,000 and $9,542. However as I mentioned previously, the $9,542 was based on using a baseline with actual emissions and it has been shown that using an existing permitted limit in the baseline is also acceptable. I am not able to determine at this time where even a range would fall. There is just no clear definitive guidance for what is considered cost effective for previously controlled units.

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[25] See PDF page 14 of DPU 7.19R-RR

[26] See pg 17 of DPU 7.18R-RR

Q. Do the "other factors" discussed previously, including deciview improvement help the Company's view that these projects are cost effective?

A. Yes and No. Mr. Gebhart seems to suggest on page 43 of his direct testimony that the Hunter and Huntington visibility improvements are 0.19 deciviews or less and that this amount is not significant. Visibility improvement may not significantly help the Company's argument. End-of-life and maintenance issues may or may not assist the Company's view since, at this time there is not significant supporting documentation although more may come later. As stated previously, the increasing sulfur content claimed by the Company will result in SO2 tons removed that are generally greater for the Hunter 1 and Hunter 2 units while the Huntington 1 unit is generally a little lower when compared to the SO2 tons removed in the Company's response to DPU 36.5[27]. In either case the tons removed are still significantly higher than what was used in Mr. Gebhart's calculations. Also mentioned previously, there appears to be compliance issues associated with the increase in coal sulfur. There are both positive and negative aspects to these other factors and it appears that the increasing sulfur issue would carry the most weight in supporting the belief that these scrubber projects are cost effective.

Q. On lines 228 to 229 of your direct testimony you mention the Company's contribution to the regional milestones as an issue that still needed to be explored. What is the Company's contribution to the regional milestones?

A. This is a rather complicated question, but I will attempt to explain my understanding for how the regional milestones work and what PacifiCorp's responsibility is to them. The proceeding discussion is based on my conversations with UDAQ personnel. Wyoming and Utah are part

[27] DPU 7.6R-RR

of the regional milestone program. Under this program, regional milestones for SO2 emissions have been established. Over the years, these milestones have changed due to factors such as other states leaving the program, litigation and new baseline inventories being used. In any case, the milestones are built, in part, on SO2 emission rates being applied to individual units such as the Hunter and Huntington units and others. The milestones in the current UT 2011 SIP[28] were built based on the Hunter 1, Hunter 2 and Huntington 1 units having a .12lb/MMBtu emission rate. The calculations used to construct the milestones in the 2011 UT SIP are in DPU Exhibit 7.21R-RR.

Q. So, from a regional milestone perspective, would PacifiCorp be held to the .12lb/MMBtu emission rate?

A. No. The .12lb/MMBtu rate was only used to build the overall milestones. Based on my conversations with UDAQ personnel it is expected that the actual 2018 emission rates from each unit will be different than what was used to construct the milestones. The spreadsheet used to calculate the regional milestones was never intended to establish BART or an expected control at any particular unit. The idea was that if a project at a plant was not cost effective, there would be emission reductions at other units in the region that would compensate for this non cost effective project not being installed. UDAQ is not concerned so much as how the milestones are met just as long as they are met.

Q. What happens if the milestones are not met?

A. If the milestones in 2018 are not met, an allocation process is used to determine an allowance for each source of emissions. The allocation methodology is designed such that each source would get enough allowances to cover the emissions at a "well controlled rate." As long as

[28] See PDF page 33 of DPU 7.20R-RR.

that source had achieved a well controlled rate penalties would not be applied. Although the definition of well controlled is still not clear to me, I was informed that sources that did not do anything with regards to the milestones would be held accountable first. A penalty of $5,000 per ton of excess emissions would be assessed in addition to the source having to purchase allowances to cover the excess emissions. The idea of these "hammers" was to give sources the incentive to do something.

Q. Why was a .12lb/MMBtu emission rate used for the Huntington 1, Hunter 1 and Hunter 2 units?

A. As stated previously, the milestones and therefore Utah's SIP had to be revised several times. During this process it was decided by EPA that when States constructed their baseline data, they had to use the new emission rates that had already been established or were in the process of being established for the various units.

Q. Once the permit has been issued with the .12lb/MMbtu limit, does it become law and enforceable?

A. My understanding is yes. So, the .12lb/MMBtu was not required from a milestone perspective but was required from a permit perspective.

Q. Why was a .12lb/MMBtu emission rate being "permitted" at Huntington 1, Hunter 1 and Hunter 2?

A. The Company's response to DPU 36.9 states:

> Specific to the Hunter and Huntington BART-eligible units, during the 1990's and early 2000's the Western Regional Air Partnership (WRAP) and the state of Utah assumed units controlling at an 80% SO_2 removal rate would be required to meet a 90% removal rate. Initially this rate was interpreted to be an emission rate of 0.10 lb/mmBtu; however, at the time of formal commitments when the permit application was submitted in August of 2006, the 90% removal requirement was

formalized to be equivalent to an emission rate of 0.12 lb/mmBtu, and the 90% removal requirement was removed.

Q. Were you able to find support for this idea that 90% removal would be required?

A. Yes. When asked independently of each other, both the Company and UDAQ provided me with the EPA's Proposed Rule, published July 20, 2001. This document is attached as DPU Exhibit 7.9R-RR. UDAQ confirmed that the 90% was used in discussion documents and draft inventories throughout that time period. UDAQ also confirmed that a lb/MMBtu approach came after 2005.

Q. If the 90% removal rate was used by UDAQ and the Company, why did WRAP assume an 80% removal rate for Hunter 1, Hunter 2 and Huntington 1 in its 2018 estimates as testified by Mr. Gebhart in his analysis?

A. I don't know. I'm assuming however that this issue will be addressed by the Company in its rebuttal testimony.

Q. Given that the .12lb/MMbtu limit was more of a permit requirement rather than a milestone requirement, has the Company attempted to quantify how their emissions compare to the regional milestones?

A. Yes. The Company's response to DPU 44.4 states:

> The list of EGUs located within the Section 309 states currently participating in the SO2 regional haze milestone program includes 19 PacifiCorp EGUs and 15 non-PacifiCorp EGUs. A copy of the workbook containing this information is provided in Attachment DPU 44.4c -1. This workbook and the information contained within it are the work products of the states participating in the 309 regional haze program. Attachment DPU 44.4c -2 is a subset of Attachment DPU 44.4c -1, which only includes PacifiCorp's units and projections.
>
> Based on the all EGU's included in the development of the milestones, the average 2018 EGU SO_2 emission rate is 0.15 lb/mmBtu. When evaluating future emissions using PacifiCorp's forecasts, with all of the controls PacifiCorp has installed or permitted to install on its units in the Section 309 region, PacifiCorp's

> system average emission rate is approximately 0.18 lb/mmBtu, which is above the EGU fleet average. This indicates that under a unit-by-unit allocation methodology, PacifiCorp would be expected to reduce its emissions even further than already anticipated.

The Company's response to DPU 44.9 also shows actual historical emissions from the 19 PacifiCorp units. These 19 units were used in the development of the regional milestones. The total 2018 emissions assumed in the milestone development from these units was 50,128 tons. As a comparison, the total emissions in 2010 (the lowest since at least 2000) from these 19 units was 69,124 tons. Again, if you wanted to quantify PacifiCorp's emissions in comparison to the milestones (recognizing that PacifiCorp isn't held, from a milestone perspective, to those emissions to build the milestones) it appears that PacifiCorp would need further reductions after 2010.

Q. Would you please summarize your testimony concerning the three disputed Utah scrubber projects?

A. Yes. Based on my research and conversations with WDAQ personnel, there is no clear definitive guidance for what should be considered cost effective for the Hunter 1, Hunter 2 and Huntington 1 scrubber projects. Multiple methodologies for calculating cost per SO2 ton removed have been accepted and no clear benchmark seems to exist from which to judge the cost per SO2 ton calculations. The other factors I have identified are mixed as to whether or not they assist in the belief that these scrubber projects are cost effective. At this time it appears that the increase in sulfur content is a significant issue that should be considered but admittedly this is based on what the Company has shared with the Division through data request responses. The Division is not able to determine at this time if the disputed scrubber projects are or not cost effective. Although the Company may not have been held to the

.12lb/MMBtu used to develop the regional milestones, it is required to meet the .12lb/MMBtu based on the permit issued by UDAQ. The .12lb/MMBtu limit appears to have originated from a 90% removal efficiency which was not only contemplated by the Company but also the state of Utah and WRAP as early as 2001. The Division will wait to read the Company's response to Mr. Gebhart's claim[29] that WRAP did not contemplate additional SO2 controls for the Hunter 1, Hunter 2, or Huntington 1 units in its 2018 regional estimates.

Q. Does this conclude your testimony?

A. Yes.

[29] UAE Exhibit RR 2.0, lines 716 to 720