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 7.0SR-RR** **Surrebuttal Revenue Requirement Testimony and Exhibits** **Matthew Croft**

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

Surrebuttal Revenue Requirement Testimony of

Matthew Croft

PUBLIC

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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. Are you the same Matthew Croft who provided direct and rebuttal 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. My testimony will address the rebuttal testimony of Mr. McDougal concerning my adjustments regarding the forecasted retirement rates as well as my adjustment to update depreciation expense. I will also address the Black Hills sale, Snake Creek sale, Condit decommissioning, Transmission Clearance Issue Corrections project, and various tax related updates proposed by Mr. McDougal in his rebuttal testimony. My testimony will also address concerns raised by UAE witness Mr. Gebhart in his rebuttal testimony. I will also clarify and or revise information in my rebuttal testimony regarding assumptions used by the Wyoming Division of Air Quality ("WDAQ") to determine the SO2 tons reduction in their various cost effective analyses. Although my rebuttal testimony regarding the SO2 tons reduction in the WDAQ analyses was based on conversations and emails with WDAQ, subsequent information has required a clarification and or revision. My testimony will also discuss the Company's most recent methodology for determining cost effectiveness for the Utah scrubber projects.

Q. Are you still proposing an adjustment to use a four year average in calculating the retirement rates?

A. Yes. This adjustment is not a “cherry picking” adjustment. The Company’s averaging methodology uses four 12 month periods and one 9 month period in a “five year average.” A nine month period will always have fewer retirements (assuming the same beginning or ending point) and therefore the Company’s average is understated. I do recognize that my methodology leaves a nine month “hole” in the data so I investigated other averaging methodologies. I investigated using the most recent three year average (CY 2007-2009), calculating a 57 month average to come up with a yearly average, grossing-up the 9 month period to a 12 month period, and taking an average of all the methodologies (including the Company’s).[1] These four other methodologies all resulted in an estimated decrease in revenue requirement that approximated my original adjustment or were greater. Again, the basic principle is that a nine month period will always have fewer retirements than a twelve month period and therefore the Company’s five year average will be understated.

Q. Are you still proposing an adjustment to use the depreciation rates based on December 2010 plant balances as opposed to the June 2010 plant balances used by the Company?

A. Yes. I have attempted to update accumulated depreciation, depreciation expense, plant additions and retirements with actual data. Updating the depreciation rates was just one part of those updates. In preparing its case, the Company used the depreciation rates from its most recent semiannual plant balances (June 2010). I have likewise attempted to use the most recent semiannual period which now is December 2010.

Q. Are you only updating with adjustments that reduce revenue requirement?

[1] See the “Scenarios” tab and the “Revised Ret Rates” tab in the excel DPU Exhibit 7.1SR-RR to 7.3SR-RR

A. No. Although some have had this effect, the Jim Bridger and Trapper mines adjustment did slightly increase revenue requirement. Likewise, I have added plant additions that were not part of the original filing but that nevertheless were needed and placed into service or that are expected to be placed into service during the forecasted period.

Q. Have you updated everything related to electric plant in service?

A. No. Admittedly there are other aspects of the capital related templates (such as hydro decommissioning and FERC account allocation of distribution additions) filed by the Company that I was not able to finish updating. There could also be others that I am not aware of. For this reason I do sympathize with the “administrative difficulty” that can arise with updates. I do believe however, that my depreciation update is a relatively simple and straight forward update.

Q. Have you accepted the Company’s rebuttal testimony proposal to include the “Transmission Clearance Issue Corrections” capital addition?

A. No. While I am not opposed to the concept of this adjustment there is simply not enough evidence to support it. At the time of preparing testimony, the Company had not provided sufficient supporting documentation for the project. Mr. McDougal’s rebuttal testimony does describe why the project is needed but it appears that the majority of the costs ($25.8 million out of $28.5 million) associated with this project are to “implement additional line surveys and make corrections where necessary. [2]” It appears that these line surveys have not been conducted yet and so the corrections and therefore the costs are unknown. Until the Company

[2] See line 587 of Mr. McDougal’s rebuttal testimony

provides supporting documentation for these costs there is not enough evidence to support it. Therefore, the Division recommends that these costs not be allowed at this time.

Q. Have you accepted the Company's adjustments related to the Black Hills transmission asset sale, Snake Creek hydroelectric sale and Condit hydroelectric decommissioning?

A. Yes. Division witness Dr. Zenger and UAE witness Mr. Higgins have proposed an adjustment for the Black Hills sale and the Company has provided the figures necessary to complete the adjustment. The Snake Creek hydroelectric sale was proposed by Mr. Higgins and has been accepted by the Company. With regards to the Condit Hydroelectric project, the Company did provide supporting documentation related to this adjustment. Included with Mr. Duvall's rebuttal testimony is the FERC Surrender Order issued to PacifiCorp as well as PacifiCorp's acceptance of the surrender order.

Q. How have you modeled these electric plant in service (EPIS) adjustments?

A. The "Scenarios" tab in the excel file DPU 7.1SR-RR to DPU 7.3SR-RR ("EPIS Templates") includes switches to turn "off" or "on" various adjustments including the depreciation rates, retirement rates, actual plant addition and retirements through March 2011, the Company's revised April 2011 to June 2012 plant addition forecast (from DPU date request 30), the Black Hills adjustment (EPIS related), Snake Creek adjustment (EPIS related) and Condit adjustment (EPIS related). All of these adjustments flow through to the plant additions and retirements, accumulated depreciation, and depreciation expense adjustments in the EPIS templates. The JAM also includes an additional adjustment column (See "Adjustments" tab) to reflect the appropriate O&M and NPC adjustments related to the Black Hills, Snake Creek and Condit adjustments. The "Scenarios" tab also includes a switch for the Transmission

Clearance Issue adjustment mentioned previously (currently turned off). The Company's rebuttal scenario (RMP Adjustments 12.13, 12.17, 12.16) was replicated in my EPIS Templates and the corresponding JAM inputs matched very closely with the Company's JAM inputs[3].

Q. Have you accepted the Company's plant related tax update, bonus depreciation update as well as the state income tax adjustment?

A. Yes. Since the Division's and Company's plant additions are very similar I have accepted the plant related tax update and bonus depreciation update. I have also accepted the Company's state income tax calculation methodology which is based on the blended statutory tax rate rather than the Income Before Tax ("IBT") factor**.** This change is consistent with the 2010 Protocol agreement which is pending before the Commission.

Q. Have you misunderstood or ignored WDAQ's determination about the cost effectiveness of the Dave Johnston Unit 3 emission controls as claimed by Mr. Gebhart on page 25 of his rebuttal testimony?

A. No. I was and am fully aware of the WDAQ analysis stating that the incremental costs of installing a new polishing fabric filter with dry FGD on Unit 3 are not reasonable. My comments about the WDAQ analyses determining that "all FGD projects on Wyoming plants are cost effective or have reasonable costs [4]" was based on my attempt to separate the Dry FGD portion of the project from the polishing baghouse[5]. Admittedly, this could have been more clear in my testimony.

Q. Did WDAQ eventually determine the baghouse to be cost effective?

[3] Within $183 for depreciation expense (UT allocated) and $4,278 on a net EPIS basis (UT allocated).
[4] See DPU Exhibit 7.0R-RR lines 168 to 169
[5] See DPU Exhibit 7.0R-RR lines 162 to 166

A. Yes. WDAQ conducted its cost effective analysis initially on a one pollutant to one control type basis. The incremental costs associated with FGD/baghouse project on Dave Johnston Unit 3 were determined to not be reasonable when just considering SO2. When just considering PM emissions the baghouse costs were also not considered reasonable. However, when considering all the benefits the baghouse provides, WDAQ determined that the baghouse costs are reasonable. Page 104 of Wyoming's State Implementation Plan ("WY SIP") states:

> 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.

Q. To this point, has Mr. Gebhart ever specifically acknowledged the above statement from the WY SIP?

A. No. Mr. Gebhart maintains that the baghouse is not cost effective.

Q. Mr. Gebhart is of the belief that "PacifiCorp embarked on a voluntary emissions control program that significantly overreached the legal requirements of the Clean Air Act." (UAE Exhibit 2.0R lines 695 – 696) Was there anything that would have prompted the Company to submit permit applications with lower limits in order to install the Utah scrubber projects?

A. Yes. 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% SO2 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 (See 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. How exactly does the 90% expectation from the state equate to the 0.12lb/mmBtu limit which was included in the Company's permit application (Notice of Intent)?

A. The Company's response to DPU 50.3 states the following.

> The 0.12 lb/mmBtu emission rate was determined and proposed by the Company in the Hunter and Huntington Notices of Intent. When relying on a percent removal efficiency as a permit limit, SO_2 emissions will increase as the fuel sulfur increases. This is unacceptable under the regional haze program which is designed to ensure that emissions decrease over time. The 0.12 lb/mmBtu emission rate in lieu of a percent removal requirement ensures that emissions will not increase even if the sulfur content of the fuel increases. The Company did not propose in the Notices of Intent, and the state did not require as a condition of granting the Approval Order, an additional limit that would require the units to scrub to the 90% removal rate.
>
> The Company's proposed 0.12 lb/mmBtu emission rate limit was based on the coal quality guarantees contained in the 2004 amendments to the SUFCO coal contract. This contract allowed a maximum sulfur content of 0.65% sulfur and a minimum coal BTU content of 10,700 Btu per pound. Using this information, the 0.12 lb/mmBtu limit was calculated as follows:
>
> The molecular weight of SO_2 is twice the molecular weight of sulfur (molecular weight of sulfur = 32, the molecular weight of SO_2 = (32 + 2*16 = 64). The SO_2 released from the coal =

(% sulfur in the coal/100) * (2 lb SO2/1 lb S) * (1,000,000 Btu/mmBtu) / (Btu/pound of coal) =

(0.65/100)*(2)*(1,000,000) / (10,700) = 1.21 pounds of SO2 per mmBtu

At the proposed removal efficiency of 90%, the emission rate =

(1.21 lb of SO2) * (1.00 - 0.90) = 0.12 lb SO2/mmBtu emission rate)

Prior to the 2004 contract amendment to the 1999 base agreement, the maximum sulfur content permitted by contract was 0.55%. When evaluating this coal quality, 90% removal would equate to a 0.10 lb/mmBtu emission rate.

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 estimate spreadsheet tables as testified by Mr. Gebhart in his analysis?

A. The Company's witness Mr. Sprott addressed this issue in his rebuttal testimony (lines 504 – 519).

> Each table carries clear caveats with two footnotes that obviously anticipated that states would make decisions different from those in the tables:
>
> "These estimates are only valid as part of the regional estimate and are not intended to establish BART estimates for individual sources." [emphasis added]
>
> "The application of regional achievable control technology estimates to individual sources has only undergone preliminary review by the states. There may be changes due to a more detailed review." [emphasis added]
>
> Hence, the tables were intended strictly as a demonstration of the feasibility of achieving the necessary reductions for the milestones proposed in the Annex and that the milestones were better than BART and were expressly not intended to be used as Mr. Gebhart is doing.

Q. Are there clarifications you would like to make to your rebuttal testimony?

A. Yes. As background, I will first show an example of how the reduction in SO2 tons is calculated. The table below shows the basic calculations used in the WDAQ and CH2MHILL analysis for the Wyodak scrubber. The actual CH2MHILL analysis shows additional assumptions such as sulfur content, coal flow rate, and others but the example below provides the basic concept in calculating the reduction in SO2 tons emitted.

Wyodak			
Baseline Emissions			
Heat Input (MMBtu/hr)		4700	(Input)
Lbs/MMBtu	x	0.5	(Input)
Lbs/Hr		2,350	
Hours Operation	x	7,884	(Input)
Lbs/Yr		18,527,400	
Lbs/Ton	/	2,000	
Tons Emitted Per Yr		9,264	
Post Control Emissions			
Heat Input (MMBtu/hr)		4700	(Input)
Lbs/MMBtu	x	0.16	(Input)
Lbs/Hr		752	
Hours Operation	x	7,884	(Input)
Lbs/Yr		5,928,768	
Lbs/Ton	/	2,000	
Tons Emitted Per Yr		2,964	
Reduction in SO2 Tons Emitted		6,299	

As can be seen in the table above, heat input and lbs/mmBtu are integral components in the SO2 tons emitted calculation. In my rebuttal testimony I discussed how WDAQ determined the Laramie River Station “Eliminate Stack Reheat System” was not cost effective. I also stated at lines 429 to 430 that that “the baseline used for the Eliminate Stack Reheat project was based on a three year average of past actual emissions.” To be more precise, the baseline emissions used for Laramie River Station were based on a three year actual average heat input and the existing permit limit. This has been confirmed with WDAQ. Line 147 of my rebuttal testimony states that “WDAQ’s analysis for the DJ3 unit used the existing permit rate (1.21 lbs/mmBtu, 13,316 tons) as the baseline and the expected control’s design (.15lb/mmBtu, 1,656 tons) as the post control emissions.” Although this was previously confirmed with WDAQ, the existing permit limit was actually 1.20 lbs/mmBtu. In discussions with the Company and WDAQ since filling rebuttal testimony, neither group seems to know exactly what the origin of the inputs used to calculate 1.21 lbs/mmBtu are based on. The 1.21 lbs/mmBtu are not the existing permit limit and looking at the actual SO2 emissions from Dave Johnston Unit 3 from 2003 to 2008 it doesn't appear that it represents actual emissions either.

Q. Why is knowing the origin of lb/mmBtu rates important?

A. The Company has been of the opinion that the previously existing permit limit should be used in calculating baseline SO2 tons emitted. Mr. Gebhart on the other hand is of the opinion that actual emissions should be used in calculating baseline SO2 tons emitted. Calculating baseline SO2 tons emitted is critical in determining whether or not the scrubber projects are cost effective.

Q. Have you been able to determine the origin of the lb/mmBtu inputs as well as the heat inputs used in calculating the baseline SO2 tons emitted in the WDAQ analyses?

A. Yes. The table below shows the origin of the inputs used to calculate the baseline and post control SO2 tons emitted for Wyodak, Naughton 3, Jim Bridger 1-3 and Dave Johnston 3. The excel spreadsheet used for the calculations below is included as DPU Exhibit 7.4SR-RR. The Operating Permit Limits identified below were verified with the Title V Operating Permits for the particular units. These operating permits are included as DPU Exhibits 7.5SR-RR and 7.6SR-RR.

		Reduction in SO2 Tons Per Year	
		Wyodak	
Baseline Emissions			
Heat Input (MMBtu/hr)		4700	Based on measured data
Lbs/MMBtu	x	0.50	Operating Permit Limit
Lbs/Hr		2,350	
Hours Operation	x	7,884	24hr x 365d x 90% Capacity Factor
Lbs/Yr		18,527,400	
Lbs/Ton	/	2,000	
Tons Emitted Per Yr		9,264	
Post Control Emissions			
Heat Input (MMBtu/hr)		4700	Based on measured data
Lbs/MMBtu	x	0.16	New Permit Limit/Control Design
Lbs/Hr		752	
Hours Operation	x	7,884	24hr x 365d x 90% Capacity Factor
Lbs/Yr		5,928,768	
Lbs/Ton	/	2,000	
Tons Emitted Per Yr		2,964	
Reduction in SO2 Tons Per Year		6,299	
		Naughton 3	
Baseline Emissions			
Heat Input (MMBtu/hr)		3700	Based on measured data
Lbs/MMBtu	x	0.50	Operating Permit Limit
Lbs/Hr		1,850	
Hours Operation	x	7,884	24hr x 365d x 90% Capacity Factor
Lbs/Yr		14,585,400	
Lbs/Ton	/	2,000	
Tons Emitted Per Yr		7,293	
Post Control Emissions			
Heat Input (MMBtu/hr)		3700	Based on measured data
Lbs/MMBtu	x	0.21	Control Design
Lbs/Hr		777	
Hours Operation	x	7,884	24hr x 365d x 90% Capacity Factor
Lbs/Yr		6,125,868	
Lbs/Ton	/	2,000	
Tons Emitted Per Yr		3,063	
Reduction in SO2 Tons Per Year		4,230	

		Jim Bridger 1-3	
Baseline Emissions			
Heat Input (MMBtu/hr)		6000	Based on measured data
Lbs/MMBtu	x	0.27	Actual Operations/Negotiated
Lbs/Hr		1,620	
Hours Operation	x	7,884	24hr x 365d x 90% Capacity Factor
Lbs/Yr		12,772,080	
Lbs/Ton	/	2,000	
Tons Emitted Per Yr		6,386	
Post Control Emissions			
Heat Input (MMBtu/hr)		6000	Based on measured data
Lbs/MMBtu	x	0.10	Control Design
Lbs/Hr		600	
Hours Operation	x	7,884	24hr x 365d x 90% Capacity Factor
Lbs/Yr		4,730,400	
Lbs/Ton	/	2,000	
Tons Emitted Per Yr		2,365	
Reduction in SO2 Tons Per Year		4,021	

		Dave Johnston 3	
Baseline Emissions			
Heat Input (MMBtu/hr)		2800	Based on measured data
Lbs/MMBtu	x	1.2064	Appears Calculated
Lbs/Hr		3,378	
Hours Operation	x	7,884	24hr x 365d x 90% Capacity Factor
Lbs/Yr		26,631,521	
Lbs/Ton	/	2,000	
Tons Emitted Per Yr		13,316	
Post Control Emissions			
Heat Input (MMBtu/hr)		2800	Based on measured data
Lbs/MMBtu	x	0.15	New Permit Limit/Control Design
Lbs/Hr		420	
Hours Operation	x	7,884	24hr x 365d x 90% Capacity Factor
Lbs/Yr		3,311,280	
Lbs/Ton	/	2,000	
Tons Emitted Per Yr		1,656	
Reduction in SO2 Tons Per Year		11,660	

Based on the examples above, WDAQ used both actuals and permit limits as inputs for the baseline emissions calculation. For the post control emissions WDAQ used either the expected control's design emissions or a lb/mmBtu level that was the same for both the expected control's design emissions and the new permit limit. Based on this information it is not clear what method would or should have been used in a cost effective analysis for the Hunter 1, Hunter 2, and Huntington 1 scrubber projects.

Q. What is the Company's current methodology for determining the denominator in the cost effectiveness analysis (Cost/SO2 Tons)?

A. The Company's most recent methodology is contained in Mr. Teply's rebuttal testimony (above line 799) as well as the Company's response to DPU 48.5. The calculations are as follows.

DOLLAR PER TON ESTIMATES EVALUATING THE TONS OF SO2 REMOVED RATHER THAN COMPARING THE TONS OF SO2 EMITTED

	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	0.6
Baseline uncontrolled emission rate, lb/mmBtu	0.892	0.892	1.024
Annual uncontrolled SO_2 emissions, tons/yr	16,752	16,752	20,067
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 SO2 removed	13,748	13,748	16,930
Future Coal Btu/lb	11,425	11,425	11,117
Future Coal Sulfur, %	0.767	0.767	0.69
Future Uncontrolled emission rate (lb/mmBtu)	1.343	1.343	1.241
Annual uncontrolled SO2 emissions, tons/yr	25,210	25,210	24,338
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	21,985
Net increase in the tons of SO_2 removed, tons/yr	**9,209**	**9,209**	**5,054**
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	$1,388

This methodology is based on comparing the SO_2 tons *removed* (uncontrolled emissions less already partially controlled emissions) before the new controls to the SO_2 tons *removed* (uncontrolled emissions less newly controlled emissions) after installation of the new controls. Also included in this methodology is considering the historical sulfur content of the coal before the new controls and the future sulfur content of the coal after installation of the new controls.

Q. In your rebuttal testimony you stated that UDAQ never intended the SO2 tons reduction in the SIP to be used in a cost effective analysis. Suppose however, you were to apply the Company's concept of SO2 tons *removed* with the Utah SIP calculations, what would be the result?

A. The results would yield SO2 tons removed very similar to what was calculated in Mr. Teply's rebuttal testimony. These calculations are shown in the excel file DPU 7.8SR-RR and originated from DPU data request 54.1. Each tab related to a particular unit in this Excel file includes the calculations provided by the Company as well as a green shaded box indicating the cost per ton of SO2 removed/emitted. This Excel file also includes a tab showing how the "Changes in Emissions" from the UT SIP (Table 6) were calculated.

Q. Has this "tons removed" methodology been used in any of the WDAQ analyses?

A. Not that I am aware. It is my understanding however that the Wyoming units were not facing the same coal quality issue that the Utah units are facing.

Q. If the Wyoming units were facing an increase in the sulfur content of coal would WDAQ or CH2MHILL have performed an analysis similar to the one presented by the

Company in Mr. Teply's testimony (line 799) and the Company's response to DPU 48.5?

A. The WDAQ analyses appear to be based on corresponding CH2MHILL analyses. These CH2MHILL analyses do incorporate assumptions about coal sulfur content[6]. Given WDAQ's and CH2MHILL consideration of the coal sulfur content it is possible, but there is no guarantee.

Q. Why was a cost effective analysis not formally performed just prior to submitting its permit application and why was this analysis not submitted with the permit application?

A. My understanding is that UDAQ did not require such an analysis.

Q. Even though UDAQ did not require such an analysis, would it seem reasonable that such an analysis should have been performed?

A. Yes. As mentioned in my direct testimony, (lines 311-313) the MEHC commitment clearly states that the environmental projects needed to be cost effective. Commitment 43 states:

> Working with the affected generation plant joint owners and with regulators to obtain required approvals, MEHC and PacifiCorp commit to install, to the extent cost-effective, the equipment likely to be necessary under future emissions control scenarios at a cost of approximately $812 million. Concurrent with any application for an air permit, MEHC and PacifiCorp will discuss its plans regarding this commitment with interested parties and solicit input.

Q. Did PacifiCorp discuss its plans with interested parties concurrent with the Hunter and Huntington scrubber permit application?

[6] See PDF page 54of DPU Exhibit 7.7SR-RR (Wyodak) as an example.

A. With regards to the Hunter 1 scrubber project, an email was sent to the parties involved in the MEHC transaction notifying them of the Company's intent to file a permit application[7]. To my knowledge however, there was not a cost effectiveness analysis of any type included with this notification to the various parties, nor was any requested by the parties receiving the notice.

Q. At any point prior to the Hunter 1 permit application was a cost effective or cost analysis performed by the Company?

A. I am aware of a cost analysis being performed for Hunter 1, Hunter 2 and the Huntington 1 scrubber projects, but it was performed almost four years prior to the Hunter 1 permit application.

Q. Suppose that such a formal analysis were performed just prior to the permit application, who would decide whether the Utah scrubber projects were cost effective or not?

A. Since UDAQ did not require such an analysis, it's not really clear if UDAQ would have performed its own assessment even if an analysis were performed by the Company. Outside of UDAQ, I don't know who would have made the cost effective determination but at a minimum the Commission and parties to the MEHC transaction should have been notified of the corresponding costs and why the Company believed the scrubbers were cost effective. The Company should have also notified the parties of the subsequent increase in costs due to the expected increase in coal sulfur content. However, I do recognize that none of the parties to the MEHC transaction, including the Division, requested cost information (to my

[7] See DPU Exhibit 7.9SR-RR

knowledge) when notified about the Company's forthcoming Hunter 1 permit application. At the time of the permit application for Hunter 1 in August 2006 the Company appears to have assumed[8] a 0.65% coal sulfur content. Based on studies performed by Sargent and Lundy, it appears that the Company later assumed a [redacted] coal sulfur content. These studies came subsequent to the Hunter 1 and Hunter 2 scrubber applications but before the Huntington 1 scrubber application. With the increase in sulfur content, the scope of the projects appears to have changed along with corresponding increases in costs. With the increase in costs an updated cost effectiveness analysis should have been performed. Even if a formal analysis was performed, the same question remains as to who would review and determine if the projects were still cost effective. As discussed previously, it is not exactly clear how the increase in sulfur content would be considered in such a determination.

Q. Even assuming the Company's "tons removed" methodology is correct, what benchmark should be used to determine if the projects are cost effective?

A. In my rebuttal testimony I explained that the $400 - $2,000 range recommended by Mr. Gebhart does not seem to be applicable because this cost range applied to *uncontrolled* units. While it seems that costs above $2,000 per ton of SO2 reduced could be cost effective for units that are already controlled, I am still not able to determine a specific benchmark. I would point out however that the Company's current methodology does yield costs for Hunter 1($1,074), Hunter 2 ($975) and Huntington 1 ($1,388) that are within Mr. Gebhart's $400 - $2,000 cost effectiveness range.

Q. Would you please summarize your testimony regarding the disputed SO2 projects?

[8] See the Company's response to DPU 50.3 stated earlier in this testimony

A. Yes. The baghouse project at Dave Johnston unit 3 was determined by WDAQ to be cost effective when considering various factors including end-of-life issues and the multiple pollutant reduction benefits the baghouse provides. In calculating the reduction in SO2 tons per year, WDAQ has calculated baseline emissions using the previously existing operating permit limit as well as actual operations. As such, aspects of both the Company's methodology and Mr. Gebhart's methodology have been used. The Company's current methodology for calculating cost effectiveness uses tons of SO2 removed rather than differences in SO2 tons emitted. The Company's methodology also takes increases in sulfur content into consideration. Since the WDAQ analyses were for units not concerned with increases in coal sulfur content, it is not entirely clear whether the Company's current methodology would have been used by CH2MHILL or WDAQ. Even if a particular methodology for determining cost effectiveness was adopted as correct, there is still no clear guidance as to what should be used as a benchmark. Although it seems reasonable for the Company to have performed a cost effective analysis just prior to submitting its permit applications, the current rate case may be the only venue in which to judge cost effectiveness since such an analysis was not required by UDAQ.

Q. Does this conclude your testimony?

A. Yes.