Introduction and Purpose of Testimony

Q. Please state your name and business address.

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

Q. Are you the same Chad A. Teply who submitted pre-filed direct testimony in this proceeding on behalf of Rocky Mountain Power ("RMP" or "Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. My testimony provides information explaining the prudence of individual pollution control projects called into question by the intervening parties. The pollution control projects included in this case are required to comply with existing regulations. Furthermore, maintaining the ability to operate our coal-fueled units by retrofitting them with current-technology emissions control equipment represents the least-cost option for our customers. Information comparing the cost of retrofitted coal-fueled generation units to other generation resource classes, including combined-cycle natural gas fueled generation and conversion of coal-fueled units to natural gas, is provided below. I will also provide testimony regarding the Company's ongoing business planning efforts and the Company's coal utilization case studies included in its integrated resource planning ("IRP") process that were designed to investigate the impacts of CO_2 cost and gas price scenarios on the Company's existing coal fleet after accounting for coal plant incremental costs.

In doing so, my testimony will respond to the direct testimony of Mr. Howard Gebhart and Mr. Kevin C. Higgins on behalf of Utah Association of Energy Users Intervention Group ("UAE"), Ms. Nancy Kelly on behalf of Western Resource Advocates ("WRA"), Dr. William Steinhurst, Ph. D. and Dr. Jeremy Fisher, Ph. D. on behalf of Sierra Club, Ms. Michele Beck on behalf of the Utah Office of Consumer Services ("OCS"), and Mr. Matthew Croft on behalf of the Utah Division of Public Utilities ("DPU") regarding prudence of the Company's pollution control expenditures for coal-fueled power generation facilities.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Introduction and Purpose of Testimony
- Summary of Parties' Concerns and Recommendations
- Need and Basis for the Projects
- Alternatives and Cost Effectiveness
- Planning

Q. Will the testimony of other Company rebuttal witnesses also respond to intervener testimony and discuss the prudence of the Company's pollution control investments in its coal-fueled generation facilities?

A. Yes. In addition to my testimony, the Company has provided rebuttal testimony from three other witnesses regarding pollution control investments.

1. Ms. Cathy Woollums provides an overview of the national and associated state issues that support the Company's decisions to invest in

environmental controls at the coal-fueled generation facilities at issue in this case. Ms. Woollums' testimony addresses (1) the key regulatory and compliance drivers for the environmental control projects, (2) the Company's approach to assessing future regulatory requirements and how those requirements may factor into its environmental controls decisions, and (3) the overlap of the Regional Haze program with other air quality regulations and how the environmental controls installed under the Regional Haze program position the Company for future compliance with environmental requirements.

2. Mr. Richard W. Sprott provides a third-party testimony regarding the history and development of the Western Regional Haze program from the perspective of an agency representative in that process and the specific application of that process to the Company. Mr. Sprott worked in the Utah Department of Environmental Quality from 1994 through 2008, and served as the Executive Director of the Department of Environmental Quality from May 2007 until his retirement in December 2008.

3. Dr. Howard Ellis provides an independent, third-party review and verification of the Company's environmental compliance planning strategies and decision-making based on 40 years of experience in the air quality field. Dr. Ellis' experience base during that period includes air quality modeling, emissions inventory development, development of air pollution compliance strategies, air pollution permitting, and air quality and meteorological monitoring.

Summary of Parties' Concerns and Recommendations

Q. Please summarize Mr. Gebhart's concerns regarding the Company's pollution control equipment investments.

A. Mr. Gebhart has developed his testimony to evaluate whether the Company's pollution control equipment investments are necessary or appropriate to meet the regulatory requirements of the Clean Air Act. He focuses his concerns primarily on the Company's scrubber (sulfur dioxide ("SO_2") control) projects included in the case, and confined his analysis to those projects. It should be noted; however, that Mr. Gebhart has taken issue with one of the Company's projects that has been previously reviewed for rate base treatment under a separate Major Plant Additions docket, namely the Company's Dave Johnston Unit 3 scrubber and baghouse project. That project only has close-out costs included in this case.

Mr. Gebhart's primary concerns are that the Company has voluntarily offered to install pollution control equipment that would otherwise not have been required by existing regulations, that the appropriate metrics of cost effectiveness have not been applied as part of the Company's decision-making processes, and specifically that costs associated with the Company's Dave Johnston Unit 3 scrubber and baghouse project and the Company's Hunter Unit 1, Hunter Unit 2, and Huntington Unit 1 scrubber projects should be disallowed. Mr Gebhart's arguments related to Hunter Units 1 and 2 and Huntington Unit 1 are largely based on his summary of an arbitration award that was applied to the Company's jointly owned Hunter Unit 2 facility.

Q. Please summarize Mr. Higgins' concern regarding the Company's pollution control equipment investments.

A. Mr. Higgins has adopted the cost effectiveness argument of Mr. Gebhart and recommends that the revenue requirements associated with the Company's scrubber projects at Dave Johnston Unit 3, Hunter Unit 1, Hunter Unit 2, and Huntington Unit1 be disallowed. Consistent with Mr. Gebhart, Mr. Higgins also takes issue with one of the Company's projects that has been previously reviewed for rate base treatment under a separate Major Plant Additions docket, namely the Company's Dave Johnston Unit 3 scrubber and baghouse project with only project close-out costs included in this case. Mr. Higgins argues that the revenue requirement associated with this project is subject to challenge before the Commission in this docket.

Q. Please summarize Ms. Kelly's concern regarding the Company's pollution control equipment investments.

A. Ms. Kelly's primary concern is that impending regulations will cause coal-fueled generation to cease to be a "low-cost resource" and suggests that a comprehensive analysis of the economic viability of further investment in the Company's coal-fueled fleet be undertaken as part of the integrated resource planning (IRP) process. Ms. Kelly further suggests that Commission acknowledgment of future IRPs complete with the requested comprehensive analysis could relieve the Company of its affirmative obligation to otherwise demonstrate prudence.

Q. Please summarize Dr. Steinhurst's concern regarding the Company's pollution control equipment investments.

A. Dr. Steinhurst's primary contention is that the Company has failed to determine whether pollution control investments contemplated in the case would be cost effective in light of known and likely environmental regulations; and that the Company has failed to properly reflect those known and likely environmental regulations or their potential costs in its resource planning. Dr. Steinhurst suggests that the Commission consider establishing a comprehensive and consistent process for considering utility proposals for major investments in its existing generating units to ensure coordination between the Company's rate requests and its IRP planning processes and principles.

Q. Please summarize Dr. Fisher's concern regarding the Company's pollution control equipment investments.

A. Dr. Fisher's primary concerns are aligned with those of Dr. Steinhurst. He contends that the Company has failed to determine whether pollution control investments presented in the case would be cost effective in light of current and upcoming environmental regulations. Dr. Fisher has also submitted an exhibit with varying degrees of specificity that depicts his perspective on future capital expenditures associated with emerging environmental regulations that the Company may be facing through the 2020 timeframe.

Q. Please summarize Ms. Beck's concern regarding the Company's pollution control equipment investments.

A. Ms. Beck's primary contention is that the Company has invested in pollution control equipment without first conducting a robust evaluation of all options for compliance with new environmental regulations. Ms. Beck's recommendation is that the Commission disallow costs associated with pollution control investments that have not been justified as part of a rigorous analytical process that considers various technology options, present and anticipated environmental regulations and different resource options.

Q. Please summarize Mr. Croft's recommendation regarding the Company's pollution control equipment investments.

A. Mr. Croft's recommendation is that the costs associated with the Company's pollution control investments presented in the case are reasonable, are needed to meet future emission limits, and are aligned with projects committed to by the Company as part of its acquisition by MEHC. Mr. Croft notes that his recommendation is based on review of the Company's filing, research of Regional Haze Rules, review of the materials associated with the Company's recent arbitration regarding Hunter Unit 2 investments, and discovery propounded by the parties in the case.

Need and Basis for the Projects

Q. Do the issues raised in the testimony referenced above exemplify the complexity in balancing stakeholder interests that the Company faces in making prudent pollution control project capital investment decisions?

A. Yes. The perspectives presented in the testimony referenced above include:

(1) ardent environmental opposition to continued investment in coal fueled generation in the face of ever evolving environmental regulations,

(2) recommendations for deferred decision-making while awaiting regulatory certainty and final EPA action, and

(3) support of the Company's pollution control investments, based on regulation of its obligation to reliably and cost-effectively serve its customers, while balancing compliance with current and anticipated likely environmental requirements and regulations.

Q. Are the pollution control investments presented in this case required to comply with existing regulations?

A. Yes. The pollution control investments presented in this case are required to comply with existing regulations including Regional Haze Rules and the Regional SO_2 Milestone and Backstop Trading Program developed in alignment with existing federal regulations and administered in Utah and Wyoming, National Ambient Air Quality Standards, New Source Review requirements, state issued construction and operating permits, and state implementation plans. Confidential Exhibit RMP___(CAT-1R) attached to this testimony provides an overview of existing regulations with which the projects presented in this case will be in compliance.

Q. Is the Company obligated to install the pollution controls required by state permits, regardless of whether final U.S. Environmental Protection Agency ("EPA") review and approval of the respective Regional Haze state implementation plans remain pending?

A. Yes. The state implementation plans, BART permits and construction permits issued by the respective state agencies for the pollution control investments presented in this case include independent requirements, enforceable by the laws of the respective states. These requirements are enforceable irrespective of whether the EPA has approved or ever does approve the respective state implementation plans.

Q. What factors does the Company consider when determining which capital investments to make in pollution control projects?

A. My direct testimony described how the Company considered state and federal environmental regulatory requirements and associated compliance deadlines; review of emerging environmental regulations and rulemaking; and analyses of alternate compliance options, among other factors, while considering these projects.

Q. Are each of these factors focused solely on compliance with environmental regulations?

A. No. As part of the Company's coal fueled units compliance planning efforts, consideration is given to the selection of appropriate pollution control technologies as well as alternate compliance options such as market purchases of replacement power, converting facilities to natural gas fuel sources, and the procurement of replacement generation. Examples of these analyses are discussed further in my testimony below.

Q. Do the factors mentioned in your direct testimony form the entire basis for the Company's pollution control investment decisions?

A. No. Other factors such as ongoing compliance with existing operating requirements, fuel supply flexibility, equipment end of life considerations, and operational efficiencies are also factors included in the Company's investment decisions.

Naughton Units 1 and 2 Scrubbers

Q. What is the primary justification for the Company's Naughton Units 1 and 2 scrubber installation projects?

A. In support of the Regional Haze program being administered by the State of Wyoming, and the associated Regional SO_2 Milestone and Backstop Trading Program, the Company completed detailed analyses of the appropriate technology to be applied to these BART-eligible Naughton facilities to achieve established emissions control objectives. Naughton Units 1 and 2 were previously unscrubbed units with permitted SO_2 emission limits of 1.2 pounds per million British thermal units ("Btu"). When completed, the Naughton scrubber projects included in this case will remove approximately 30,000 tons of SO_2 per year and will support the continued operation of these cost effective generation facilities, while maintaining compliance with permitted SO_2 emissions limits consistent with presumptive BART limits (0.15 pounds per million Btu) and supporting established regional compliance milestones. Additional information supporting the post-project cost effectiveness of these units is provided in testimony below.

Q. Are operational capabilities afforded by the Naughton Units 1 and 2 scrubber installation projects also expected to support compliance with the Utility Maximum Achievable Control Technology ("MACT") requirements for hazardous air pollutants ("HAPs") proposed in March 2011?

A. Yes. As proposed in general terms, the Utility MACT establishes an emission limit for mercury HAPs of 1.2 pounds per trillion Btu, a surrogate emission limit for acid gases HAPs compliance via a SO_2 emission limit of 0.20 pounds per million Btu, and a surrogate emission limit for non-mercury metallic HAPs compliance via a particulate matter (PM) emission limit of 0.030 pounds per million Btu. Based on the Utility MACT emission limits currently proposed, the operational capabilities afforded by the Naughton Units 1 and 2 scrubber installation projects are expected to directly support acid gases HAPs MACT compliance and benefit both mercury and non-mercury metallic HAPs compliance.

Wyodak Baghouse

Q. What is the primary justification for the Company's Wyodak baghouse installation project?

A. In support of the Regional Haze program being administered by the State of Wyoming, and the associated Regional SO_2 Milestone and Backstop Trading Program, the Company completed detailed analyses of the appropriate technology to be applied to this BART-eligible Wyodak facility to achieve established emissions control objectives. Wyodak was previously configured with a dry scrubber and electrostatic precipitator with permitted SO_2 emission limits of 0.50 pounds per million Btu and permitted PM emission limits of 0.10 pounds per million Btu. The internal components of the electrostatic precipitator had reached the end of their useful life as a direct result of corrosion caused by moisture carryover from the existing upstream dry scrubber. Without the benefit of a downstream baghouse, the existing dry scrubber was required to operate in a lower temperature range to improve SO_2 removal, which results in moisture carryover. The Wyodak baghouse project included in this case results in the removal of approximately 6,000 tons of SO_2 emissions per year and allows the facility to meet a PM emission limit of 0.015 pounds per million Btu. The project supports continued operation of this cost effective generation facility, while maintaining compliance with permitted SO_2 emissions limits consistent with presumptive BART limits and supporting established regional compliance milestones. Additional information supporting the post-project cost effectiveness of these units is provided in testimony below.

Q. Are operational capabilities afforded by the Wyodak baghouse installation project also expected to support compliance with the Utility HAPs MACT requirements proposed in March 2011?

A. Yes. Based on the Utility MACT emission limits currently proposed, the operational capabilities afforded by the Wyodak baghouse installation project are expected to directly support acid gases and non-mercury metallic HAPs MACT compliance, and benefit mercury HAPs compliance.

Dave Johnston Units 3 and 4 Scrubbers and Baghouses

Q. What is the primary justification for the Company's Dave Johnston Units 3 and 4 scrubber and baghouse installation projects?

A. In support of the Regional Haze program being administered by the State of Wyoming, and the associated Regional SO_2 Milestone and Backstop Trading Program, the Company completed detailed analyses of the appropriate technology to be applied to the BART-eligible Dave Johnston Units 3 and 4 facilities to achieve established emissions control objectives. The Dave Johnston Unit 3 facility was previously configured as an unscrubbed unit with an electrostatic precipitator. With that configuration, the unit was permitted with an SO_2 emission limit of 1.20 pounds per million Btu and a PM emission limit of 0.23 pounds per million Btu. It should be noted that the Dave Johnston Unit 3 scrubber and baghouse project has been previously considered for rate base treatment under a separate Major Plant Additions docket. The Dave Johnston Unit 4 facility was previously configured as an unscrubbed unit with wet particulate removal equipment, although the wet particulate scrubber was able to achieve a marginal level of SO_2 reduction via lime injection. With that configuration, the unit was permitted with SO_2 emission limits of 0.50 pounds per million Btu and PM emission limits of 0.21 pounds per million Btu. When completed, the Dave Johnston scrubber and baghouse addition projects included in this case will result in the removal of approximately 13,000 tons of SO_2 emissions per year and will allow the affected units to meet PM emission limits of 0.015 pounds per million Btu. The projects will support continued operation of these cost effective generation facilities, while maintaining compliance with permitted SO_2 emissions limits consistent with presumptive BART limits and supporting established regional haze milestones. Additional information supporting the post-project cost effectiveness of these units is provided in testimony below.

Q. Outside of the BART review process, what other considerations led to the Company's selection of a dry scrubber and baghouse installation on Dave Johnston Unit 3 as the most cost effective option for continued plant operation?

A. As discussed in the testimony of Mr. Gebhart, the Company evaluated SO_2 removal options for Dave Johnston Unit 3 that included cases that would have utilized the existing electrostatic precipitator for that unit, rather than installing a baghouse. The Company also included that option in its requests for proposals package that was issued to the competitive market soliciting bids for the Dave Johnston Units 3 and 4 projects. Unfortunately, none of the bidders in the competitive market chose to base their proposal on that option. As Mr. Gebhart notes, the dry scrubber and electrostatic precipitator option does not provide the same level of emissions control as a dry scrubber and baghouse option, and in the case of the Dave Johnston facility, that option suffered from physical site constraints, equipment layout concerns, and constructability concerns as evidenced by the lack of competitive market bid interest.

Q. Are operational capabilities afforded by the Dave Johnston Units 3 and 4 scrubber and baghouse installation projects also expected to support compliance with the Utility HAPs MACT requirements proposed in March 2011?

A. Yes. Based on the Utility MACT emission limits currently proposed, the operational capabilities afforded by the Dave Johnston Units 3 and 4 scrubbers and baghouse installation projects are expected to directly support acid gases and non-mercury metallic HAPs MACT compliance, and benefit mercury HAPs compliance.

Huntington Unit 1 and Hunter Unit 2 Baghouses

Q. What is the primary justification for the Company's Huntington Unit 1 and Hunter Unit 2 baghouse projects?

A. The Huntington Unit 1 and Hunter Unit 2 facilities were previously configured with electrostatic precipitators with PM emission limits of 0.10 pounds per million Btu and 0.05 pounds per million Btu, respectively. The internal components of the electrostatic precipitator on each of these units had reached the end of their useful life. The Huntington Unit 1 and Hunter Unit 2 baghouse projects included in this case allow the facilities to meet a PM emission limit of 0.015 pounds per million Btu. The baghouse projects at Huntington Unit 1 and Hunter Unit 2 are also key contributors to the ability to scrub 100% of the flue gas and operate wet stacks, by effectively allowing the opacity monitors for those units to be relocated upstream of the wet scrubbers. Although the scrubber and baghouse projects on Huntington Unit 1 and Hunter Unit 2 are not necessarily dependent on or caused by each other; they are interrelated. The projects support continued operation of these cost effective generation facilities, while maintaining compliance with permitted emissions limits. Additional information supporting the post-project cost effectiveness of these units is provided in testimony below.

Q. How has ongoing compliance with existing operating requirements factored into planning of the Huntington Unit 1 and Hunter Unit 2 baghouse projects?

A. The Huntington Unit 1 and Hunter Unit 2 baghouse will significantly reduce particulate matter emissions and improve the respective facility's ability to comply with existing opacity standards.

Q. Are operational capabilities afforded by the Huntington Unit 1 and Hunter Unit 2 baghouse installation projects also expected to support compliance with the Utility HAPs MACT requirements proposed in March 2011?

A. Yes. Based on the Utility MACT emission limits currently proposed, the operational capabilities afforded by the Huntington Unit 1 and Hunter Unit 2 baghouse installation projects are expected to directly support mercury and non-mercury metallic HAPs MACT compliance. It is anticipated that these projects will obviate the need for additional mercury emissions controls capital projects and the associated reagent costs on these units.

Huntington Unit 1 Scrubber

Q. What is the primary justification for Company's Huntington Unit 1 scrubber project?

A. In support of the Regional Haze program being administered by the State of Utah, and the associated Regional SO_2 Milestone and Backstop Trading Program, the Company completed detailed analyses of the appropriate technology to be applied to this BART-eligible facility to achieve established emissions control objectives. Huntington Unit 1 was previously configured with a wet scrubber with permitted

SO_2 emission limits of 0.21 pounds per million Btu (or a minimum of 80% removal, whichever is more stringent). The Huntington Unit 1 scrubber project included in this case will result in the removal of approximately 5,100 tons of SO_2 per year. The project will support the continued operation of this cost effective generation facility, while maintaining compliance with permitted SO_2 emissions limits with better than presumptive BART performance and supporting established regional compliance milestones. Additional information supporting the post-project cost effectiveness of these units is provided in testimony below.

Q. What are the key subcomponents of the Huntington Unit 1 scrubber project?

A. As further described in my pre-filed direct testimony, there are three key subcomponents of the Huntington Unit 1 scrubber project; namely:

(1) scrubber vessel, recycle pumps, and reagent injection system upgrades intended to improve SO2 removal efficiency within the flue gas desulfurization (FGD) system,

(2) scrubber waste handling system replacement intended to increase waste handling capacity of the system to remove free liquids from the waste stream and to replace certain end-of-life equipment and components that were no longer operating to original design specifications or otherwise unreliable, and

(3) closure of the scrubber bypass duct and wet stack conversion activities. It is important to note that the costs associated with subcomponent (3) are included in the Huntington Unit 1 baghouse project contract due primarily to site work area logistics, and are included in this case as such.

Q. How has ongoing compliance with existing operating requirements factored into planning of the Huntington Unit 1 scrubber project?

A. The Huntington Unit 1 scrubber waste handling system replacement will ensure that the final scrubber waste product will not contain any free liquids and can properly be disposed in the onsite landfill. The discussion pertaining to Figure 3 below for Hunter Units 1 and 2 provides additional detail in this regard and is also applicable to Huntington Unit 1. The Huntington Unit 1 scrubber waste thickener system had reached the end of its useful life and was otherwise unreliable.

Q. Are costs for both key subcomponents of the Huntington Unit 1 scrubber project included in this case?

A. Yes. The FGD removal efficiency subcomponent was placed in service in November 2010 and the scrubber waste handling subcomponent was placed in service in March 2011.

Q. Are operational capabilities afforded by the Huntington Unit 1 scrubber project also expected to support compliance with the Utility HAPs MACT requirements proposed in March 2011?

A. Yes. Based on the Utility MACT emission limits currently proposed, the operational capabilities afforded by the Huntington Unit 1 scrubber project are expected to directly support acid gases HAPs MACT compliance.

Hunter Unit 2 Scrubber

Q. What is the primary justification for Company's Hunter Unit 2 scrubber project?

A. In support of the Regional Haze program being administered by the State of Utah, and the associated Regional SO_2 Milestone and Backstop Trading Program, the Company completed detailed analyses of the appropriate technology to be applied to this BART-eligible facility to achieve established emissions control objectives. Hunter Unit 2 was previously configured with a wet scrubber with permitted SO_2 emission limits of 0.21 pounds per million Btu (or a minimum of 80% removal, whichever is more stringent). The Hunter Unit 2 scrubber project included in this case will result in the removal of approximately 9,200 tons of SO_2 per year. The project will support the continued operation of this cost effective generation facility, while maintaining compliance with permitted SO_2 emissions limits with better than presumptive BART performance and supporting established regional compliance milestones. Additional information supporting the post-project cost effectiveness of these units is provided in testimony below.

Q. What are the key subcomponents of the Hunter Unit 2 scrubber project?

A. As further described in my pre-filed direct testimony, there are four key subcomponents of the Hunter Unit 2 scrubber project; namely:

(1) scrubber vessel, recycle pumps, and reagent injection system upgrades intended to improve SO_2 removal efficiency within the FGD system,

(2) reagent preparation system replacement intended to increase reagent preparation capacity of the system to accommodate increased coal sulfur content and to replace certain end-of-life equipment and components that were no longer operating to original design specifications or otherwise unreliable,

(3) scrubber waste handling system replacement intended to increase waste

handling capacity of the system to accommodate increased coal sulfur content and to replace certain end-of-life equipment and components that were no longer operating to original design specifications or otherwise unreliable, and

(4) closure of the scrubber bypass duct and wet stack conversion activities. It is important to note that the costs associated with subcomponent (4) are included in the Hunter Unit 2 baghouse project contract due primarily to site work area logistics, and are included in this case as such.

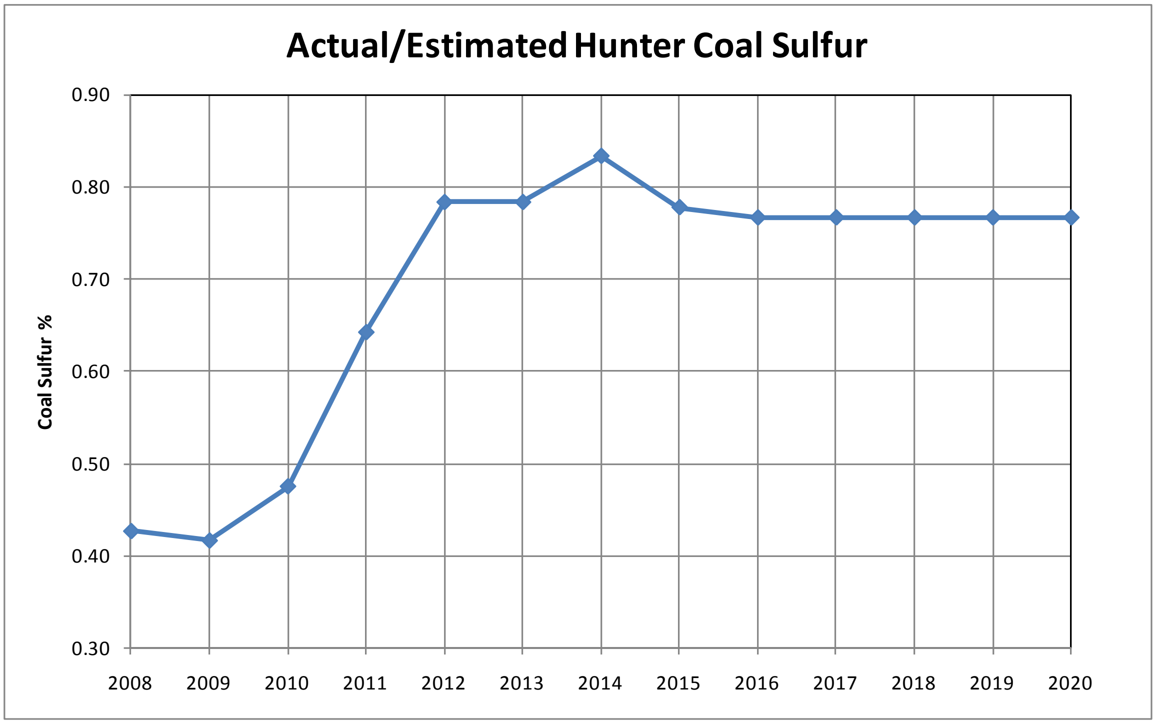
Q. How has ongoing compliance with existing operating requirements factored into planning of the Hunter Unit 2 scrubber project?

A. The Hunter Unit 2 scrubber waste handling system replacement will ensure that the final scrubber waste product will not contain any free liquids and can properly be disposed in the onsite landfill. The discussion pertaining to Figure 3 below provides additional detail in this regard. The Hunter Unit 2 scrubber waste thickener system had reached the end of its useful life and was otherwise unreliable.

Q. How has fuel supply flexibility factored into planning of the Hunter Unit 2 scrubber project?

A. As the Company developed its final project scoping requirements for the Hunter Units 1 and 2 scrubber projects, the Company became aware of anticipated changes in fuel quality for the Hunter facility that needed to be integrated into the Company's project plans. The fuel quality forecasts received include an increase in coal sulfur content that will exceed the capacities of the existing reagent preparation system and the existing scrubber waste handling system. Testimony regarding the Hunter facility's coal quality forecasts is provided in the rebuttal testimony of Ms. Cindy Crane. The following figure provides an overview of the expected coal sulfur content trend.

Figure 1



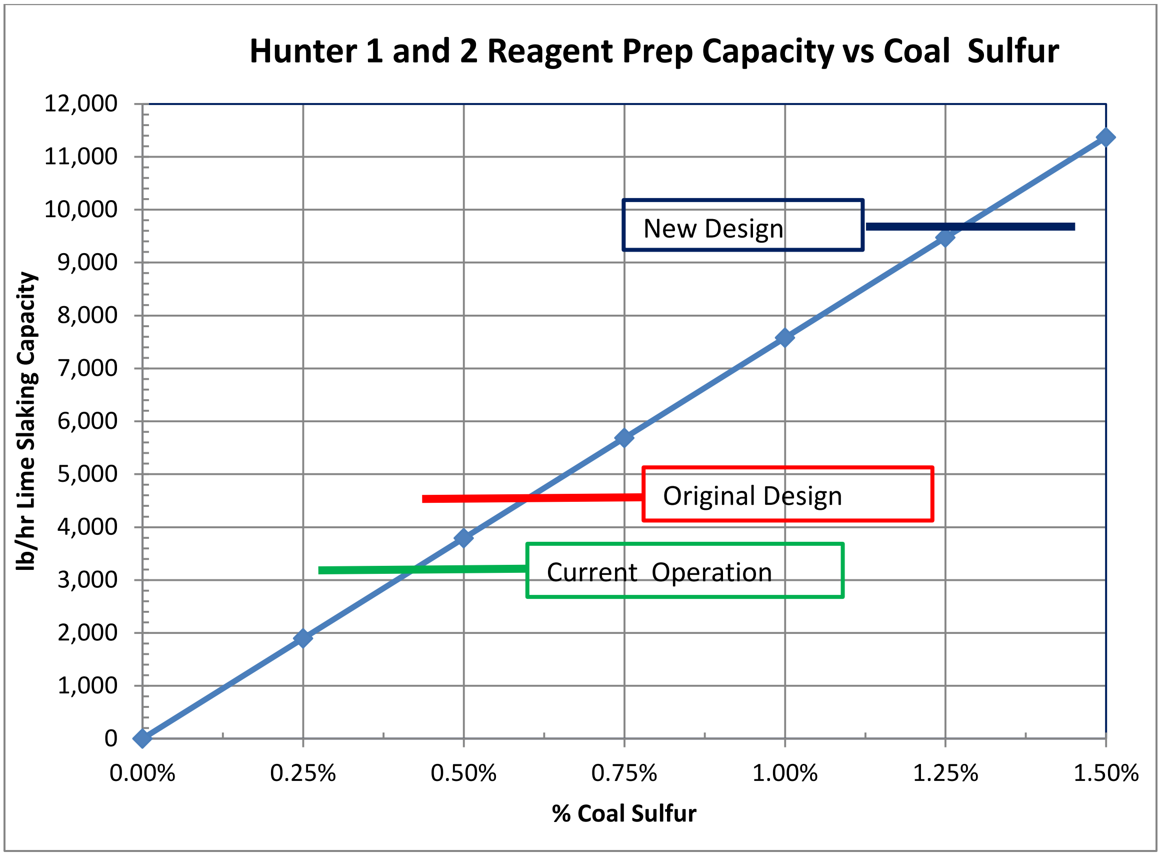
Q. Did this change in forecasted fuel quality increase the scope and cost of the Hunter Unit 2 scrubber project?

A. Yes. The scope of the Hunter Unit 2 scrubber project as originally defined and reviewed was primarily limited to scrubber vessel, recycle pumps, and reagent injection system upgrades, as well as wet stack conversion related activities, intended to improve SO_2 removal efficiency within the FGD system. The change in forecasted fuel quality is a primary driver for reagent preparation system replacement costs and scrubber waste handling system replacement costs, which are two of the three key subcomponents of the final scrubber project scope of work. The Company's share of project costs associated with those project subcomponents is approximately $11 million and approximately $19 million, respectively, compared to the Company's share of project costs associated with FGD system efficiency and wet stack conversion related activities of approximately $22 million.

Q. How does the forecasted change in fuel quality impact the scope and cost of the scrubber project subcomponents discussed above?

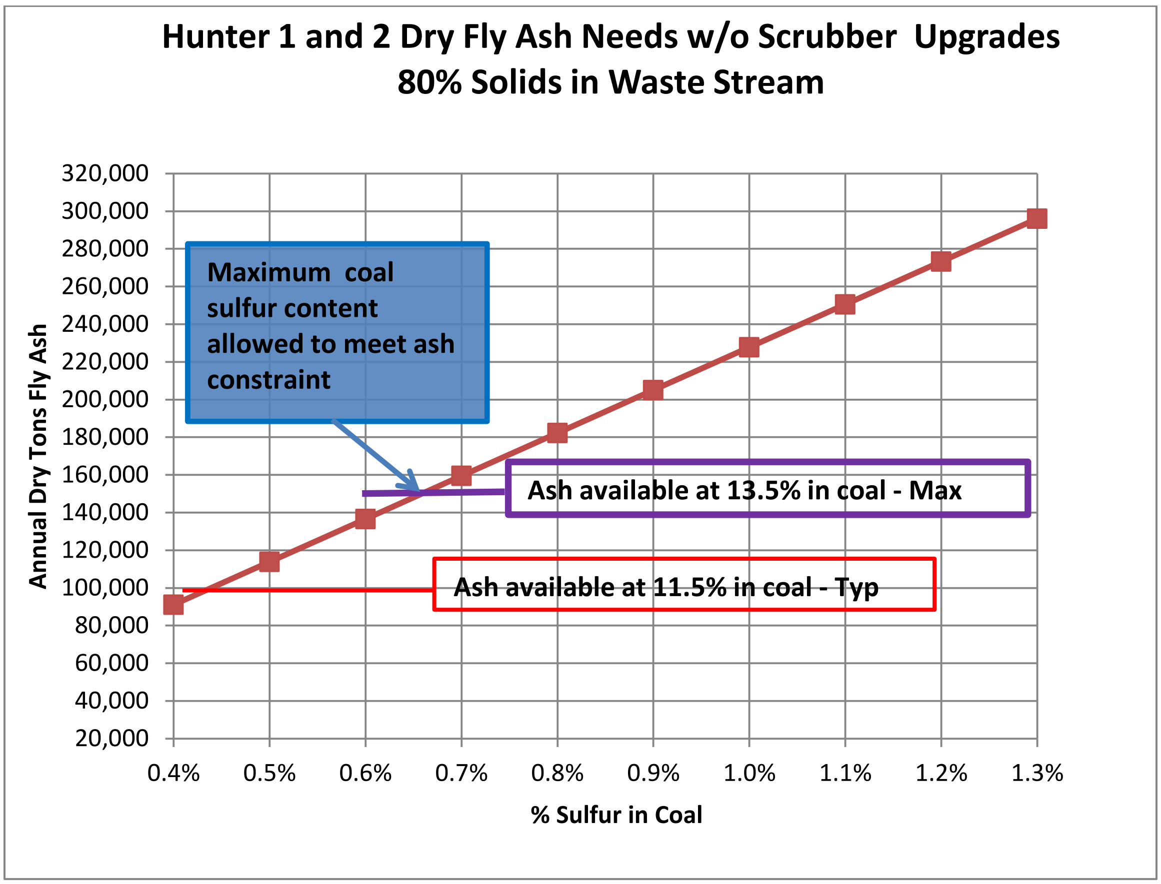
A. Forecasted fuel quality changes result in almost twice the amount of sulfur being introduced into the Hunter units on an annual average basis across the 10-year planning horizon, when compared to historical averages for delivered coal sulfur content. The expectation is that individual coal seams may produce as much as three times the amount of sulfur on a spot basis, when compared to historical averages for delivered coal sulfur content. The ability to produce enough reagent to chemically react with this increased sulfur in the units' flue gas requires larger equipment, upsized infrastructure such as piping and power distribution, and more efficient scrubber performance. Figure 2 below provides a graphical representation of the reagent preparation capacity of the original Hunter scrubbers versus the equipment installed as part of the respective scrubber projects at permitted emissions limits. The new design allows the units to accept and control significantly higher sulfur content in the coal supplied, and supports the ability of the units to receive coal from the various cost competitive mines serving the Company's Utah facilities, as further discussed in Ms. Crane's rebuttal testimony.

Figure 2



The ability to receive and dewater the increased waste streams associated with higher sulfur coal has the same effect on waste handling system capacity requirements. Figure 3 below provides a graphical representation of the limitations of the original scrubber waste handling systems regarding ash and sulfur content of the coal supplied to the units. As shown, at typical coal ash content the original waste handling system capacity was capable of effectively processing coal limited to 0.4% to 0.5% sulfur, without the need to manage blending via additional measures, which could include sourcing and manually blending off-site fly ash. At maximum coal ash content, the original waste handling system capacity could accommodate up to approximately 0.65% sulfur coal. Neither of these scenarios will support protected fuel quality changes for these units. The waste handling system installed as part of the scrubber projects does not rely on fly ash blending, and therefore also accommodates coal from the various cost competitive mines serving the Company's Utah facilities.

Figure 3



Q. Why is the ability to accommodate the forecasted change in fuel quality important?

A. The ability to fuel the Hunter units on coal with higher sulfur content while meeting new emission limits is fundamental to the Company's ability to maintain competitive fuel and generation costs at this facility.

Q. Is the Hunter Unit 2 scrubber project still cost effective when considering the costs associated with this additional scope?

A. Yes. Additional information supporting the post-project cost effectiveness of this unit is provided in testimony below.

Q. Are costs for all key subcomponents of the Hunter Unit 2 scrubber project included in this case?

A. Yes.

Q. Are operational capabilities afforded by the Hunter Unit 2 scrubber project also expected to support compliance with the Utility HAPs MACT requirements proposed in March 2011?

A. Yes. Based on the Utility MACT emission limits currently proposed, the operational capabilities afforded by the Hunter Unit 2 scrubber project are expected to directly support acid gases HAPs MACT compliance.

Hunter Unit 1 Scrubber

Q. What is the primary justification for Company's Hunter Unit 1 scrubber project?

A. The primary justification of the Company's Hunter Unit 1 scrubber is the same as that for the Hunter Unit 2 scrubber provided above. Hunter Unit 1 was previously configured with a wet scrubber with permitted SO_2 emission limits of 0.21 pounds per million Btu (or a minimum of 80% removal, whichever is more stringent). The Hunter Unit 1 scrubber project included in this case will result in the removal of approximately 9,200 tons of SO_2 per year. The project will support the continued operation of this cost effective generation facility, while maintaining compliance with permitted SO_2 emissions limits with better than presumptive BART performance and supporting established regional compliance milestones. Additional information supporting the post-project cost effectiveness of these units is provided in testimony below.

Q. What are the key subcomponents of the Hunter Unit 1 scrubber project?

A. As further described in my pre-filed direct testimony, there are four key subcomponents of the Hunter Unit 1 scrubber project; namely:

(1) scrubber vessel, recycle pumps, and reagent injection system upgrades intended to improve SO_2 removal efficiency within the FGD system,

(2) reagent preparation system replacement intended to increase reagent preparation capacity of the system to accommodate increased coal sulfur content and to replace certain end-of-life equipment and components that were no longer operating to original design specifications or otherwise unreliable,

(3) scrubber waste handling system replacement intended to increase waste handling capacity of the system to accommodate increased coal sulfur content and to replace certain end-of-life equipment and components that were no longer operating to original design specifications or otherwise unreliable, and

(4) closure of the scrubber bypass duct and wet stack conversion activities.

Q. Is your previous testimony regarding compliance with existing operating requirements and fuel supply flexibility discussions for the Hunter Unit 1 scrubber project applicable to the Hunter Unit 2 scrubber project as well?

A. Yes.

Q. Are costs for all three key subcomponents of the Hunter Unit 1 scrubber project included in this case?

A. No. Only costs associated with the scrubber reagent preparation system are included in this case. Costs for the FGD removal efficiency subcomponent, the scrubber waste handling subcomponent, and the wet stack conversion related activities are not included in this case.

Q. Are operational capabilities afforded by the Hunter Unit 1 scrubber project also expected to support compliance with the Utility HAPs MACT requirements proposed in March 2011?

A. Yes. Based on the Utility MACT emission limits currently proposed, the operational capabilities afforded by the Hunter Unit 1 scrubber project are expected to directly support acid gases HAPs MACT compliance.

Huntington Unit 1 and Hunter Units 1 and 2 Scrubbers

Q. How have equipment end of life considerations factored into planning of the Huntington Unit 1 and Hunter Units 1 and 2 scrubber projects?

A. The replacement of various scrubber system elements at those facilities is an example of how end of life of existing equipment is a partial driver for the projects at issue. These elements include scrubber vessel work scope, scrubber recycle pump replacements, and scrubber reagent injection nozzle replacements.

By planning the scrubber project tie-ins to coincide with planned maintenance outage cycles for the units, the projects were able to replace equipment and components that had exhausted their useful life, and at the same time address system capacity and compliance requirements.

Q. How have operational efficiency considerations factored into planning of pollution control investments presented in this case?

A. Operational efficiency considerations are included in the technical specifications for each of the Company's pollution control projects. The material handling phases of the Huntington Unit 1 and Hunter Units 1 and 2 scrubber projects are key examples of the Company's efforts to create operational efficiencies. The discussion regarding Figure 3 above is pertinent to each of these installations. These projects result in the installation of scrubber waste dewatering equipment that eliminates the inefficient manual management of fly ash blending processes. Thus, in addition to addressing system capacity concerns and maintaining waste disposal compliance, these projects increased operational efficiencies.

Jim Bridger 3 Scrubber

Q. What is the primary justification for Company's Jim Bridger Unit 3 scrubber project?

A. In support of the Regional Haze program being administered by the State of Wyoming, and the associated Regional SO_2 Milestone and Backstop Trading Program, the Company completed detailed analyses of the appropriate technology to be applied to this BART-eligible facility to achieve established emissions control objectives. Jim Bridger Unit 3 was previously configured with a wet scrubber with permitted SO_2 emission limits of 0.30 pounds per million Btu. The Jim Bridger Unit 3 scrubber project included in this case will result in the removal of approximately 4,500 tons of SO_2 emissions per year and will support continued operation of this cost effective generation facility, while maintaining compliance with permitted SO_2 emissions limits consistent with presumptive BART performance and supporting established regional compliance milestones. Additional information supporting the post-project cost effectiveness of this unit is provided in testimony below.

Q. Are operational capabilities afforded by the Jim Bridger Unit 3 scrubber project also expected to support compliance with the Utility HAPs MACT requirements proposed in March 2011?

A. Yes. Based on the Utility MACT emission limits currently proposed, the operational capabilities afforded by the Jim Bridger Unit 3 scrubber project are expected to directly support acid gases HAPs MACT compliance.

Installation Schedules

Q. Are the pollution control investments contemplated in this case being installed in an efficient manner?

A. Yes. Emission reduction projects of the number and size described above take many years to engineer, plan, and build. When considering a fleet the size of the Company's, there is a practical limitation on available construction resources and labor. There is also a limit on the number of units that may be taken out of service at any given time, as well as the level of construction activities that can be supported by the local infrastructures at and around these facilities. Additional cost and construction timing limitations include the loss of large generating resources during some parts of construction and the associated impact on the reliability of the Company's electrical system during these extended outages. In other words, it is not practical, and it is unduly expensive, to expect to build these emission reduction projects all at once or even in a compressed time period.

Q. Do the pollution control investments contemplated in this case meet the "used and useful" standard?

A. Yes. Each of these investments achieves its original intent, provides benefit to customers, and allows the Company to maintain timely compliance with state issued permits, state implementation plans, and regional SO_2 milestones and backstop trading programs. They are both used and useful.

Alternatives and Cost Effectiveness

Q. Does the Company agree that it has not presented sufficient information for the Commission to be able to evaluate the prudence of the capital investments in pollution control equipment contemplated in this case?

A. No. Through the Company's filings and participation in the discovery processes in this Docket and other proceedings such as the IRP, the Company has provided the Commission and parties with thorough and responsive information regarding the prudence of its pollution control investments.

Q. Has the Company provided cost information comparing the cost of continued operation of the retrofitted coal fueled generation units contemplated in this case to its other generation sources, including natural gas fueled generation?

A. Yes. The Company has responded to several data requests in various dockets in this regard. To compare the cost of retrofitted coal fueled generation units to other generation resource classes, Confidential Exhibit RMP___(CAT-2R) was developed to present the 2009 embedded generation bus bar cost per megawatt-hour differences of the various generation resources within the Company's generation fleet, including combined-cycle natural gas fueled generation and conversion of coal-fueled units to natural gas. Confidential Exhibit RMP___(CAT-3R) also provides the incremental revenue requirement associated with the pollution control equipment retrofits presented in this case on a dollars per megawatt-hour basis adjusted to 2009 dollars.

In general terms, the capital cost on a dollars per megawatt basis to retrofit pollution controls on existing coal fueled generation is approximately the same cost to build a new combined cycle natural gas generation unit, though it can be less expensive to retrofit pollution controls depending on specific unit requirements. However, fuel costs will overwhelm the capital cost competitiveness of a combined cycle natural gas unit when compared to a retrofitted coal fueled facility. Natural gas on a dollars per million Btu basis is approximately triple the cost of coal, and even when considering the efficiency differences, the cost of electricity generated by an emission controlled coal fueled facility will be significantly less than the cost of electricity from a new combined cycle unit.

These exhibits demonstrate that maintaining the ability to operate the existing coal units by retrofitting the units with the pollution control equipment represents the least-cost option for customers. This is even before considering factors associated with retirement of the coal units prior to their ratemaking depreciation lives, such as stranded depreciation expense, the economic impact on Utah, the loss of fuel diversity in the generation portfolio, and the impact on system reliability.

Q. Has the Company applied least cost principles to selection of its pollution control investments?

A. Yes. Various project revenue requirement analyses have determined the lower cost alternative to customers for achieving the target level of emission reduction or control. These take the form of comparing the present value revenue requirement impact of one technology to another and determining the present value revenue requirement differential (PVRR(d)) benefit to customers. I will further explain these analyses in the following testimony.

Q. Has the Company assessed the costs of continuing to invest in individual coal fueled generation assets versus replacing the lost generation with market purchases?

A. Yes. The Company has developed economic analyses that provide an overview of the PVRR(d) benefits associated with its pollution control investments, with consideration given to potential CO_2 costs and resulting market pricing assumptions. Confidential Exhibit RMP___(CAT-4R) and Confidential Exhibit RMP___(CAT-5R) provide the results of said analyses at various points in time and with various CO_2 costs and market pricing assumptions. Confidential Exhibit RMP___(CAT-4R) provides a PVRR(d) view of the projects presented in this case at the time of planning and approval of the pollution control investments, utilizing the CO_2 cost and market pricing assumptions of the Company's then current business plan. Confidential Exhibit RMP___(CAT-5R) provides a PVRR(d) view of the units that received the pollution control investments presented in this case on a going-forward basis, utilizing CO_2 cost and market pricing assumptions consistent with the Company's current 10-year business plan and the System Optimizer Coal Utilization Case Studies referenced below. These PVRR(d) analyses provide positive results for the various scenarios presented and further demonstrate prudence of the pollution control investments presented in this case. These analyses also offer insight into the potential impacts of various CO_2 cost and market pricing scenarios on investment recovery periods.

Q. Has the Company assessed the costs of continuing to invest in individual coal fueled generation assets versus the cost of converting the units to natural gas as fuel source?

A. Yes. The Company has developed economic analyses intended to provide an overview of the PVRR(d) benefits associated with its pollution control investments, with consideration given to potential CO_2 costs and resulting market pricing assumptions, versus natural gas repowering scenarios. Confidential Exhibit RMP___(CAT-6R) provides the PVRR(d) results of said natural gas repowering analyses. The results of these PVRR(d) analyses provide positive results for the various scenarios presented and further demonstrate prudence of the pollution control investments presented in this case, and also offer insight into the potential impacts of various CO_2 cost and market pricing scenarios on investment recovery periods.

Q. Does the Company believe that it has appropriately assessed the cost effectiveness of the pollution control investments contemplated in this case?

A. Yes. In assessing when and whether to proceed with pollution control investments, the Company has considered cost effectiveness of reasonable options. Measures of cost impacts on a bus bar dollars per mega-watt-hour basis have been reviewed, as well as the cost to remove a ton of a pollutant, which is typically applied specifically as part of BART determination processes.

Q. Does the Company agree with Mr. Gebhart's assertion that any costs for BART control on coal-fired electric generating unit SO_2 emissions control projects that exceed $2,000 per ton SO_2 removed should not be designated as BART unless other regulatory factors in the analysis warrant a higher cost level?

A. No. While the Company has argued from a similar position as Mr. Gebhart in past discussions with the EPA and state agencies regarding the appropriate cost effectiveness criteria to apply to specific projects on a cost per ton removed basis, the EPA and state agencies are not bound by the cost effectiveness recommendations included in the EPA's preamble for BART rulemaking referenced in Mr. Gebhart's testimony. In addition, cost effectiveness of specific projects will most definitely be impacted by factors other than the "regulatory factors" that Mr. Gebhart identifies as the only allowance that would warrant a higher cost level for a project (see lines 179 through 183 of Mr. Gebhart's direct testimony). Other project specific factors that have the potential to impact project scoping and costs could include projected changes in fuel quality, operational compliance issues with existing systems, equipment end-of-life issues, site constraints, and market availability of equipment and labor.

Q. Have agency actions supported the Company's assertion that the EPA and state agencies have demonstrated wide-ranging discretion in assessing cost effectiveness of pollution control projects?

A. Yes. Recently, BART determinations issued by the state of New Mexico for emission control projects have demonstrated that removal costs of $7,500 per ton are not considered cost prohibitive. Although this specific example is related to NOx 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 effectiveness standards that they apply under the Regional Haze Rules. Although the EPA has provided ranges of cost effectiveness for both SO_2 and NOx, 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 determination for the Four Corners and Navajo Power stations.

Q. Are particulate matter emissions reduction projects typically evaluated on the same cost per ton removed standards?

A. No. Particulate matter emission reductions cannot typically be compared to this same cost per ton removal standard since the incremental emissions improvement will be much smaller due to the relatively high removal efficiency level of existing particulate matter removal equipment. It should also be noted that when ongoing emissions compliance and/or equipment end-of-life issues must be addressed, the dollar per incremental ton removed evaluation is not applicable.

Q. Does the Company believe that Mr. Gebhart has appropriately assessed the cost effectiveness of the pollution control investments that he recommends for disallowance in this case?

A. No. In assessing the cost effectiveness of the Huntington Unit 1 and Hunter Units 1 and 2 scrubber projects that he recommends for disallowance, Mr. Gebhart has failed to consider key project specific planning inputs, including coal quality and operational compliance, that must be considered when evaluating the cost effectiveness of those projects. With respect to the Dave Johnston Unit 3 scrubber and baghouse project that he recommends for disallowance, Mr. Gebhart failed to consider project specific constraints and ultimate commercial viability of his recommended solution.

Q. Has the Company assessed the cost effectiveness of the Hunter Units 1 and 2 scrubber projects in light of those key project specific planning inputs.

A. Yes. The Hunter units are in a unique situation compared to the Company's other units in that 1) the historic emission rates were driven by an 80% percent removal requirement and not by a specific pounds per million Btu emission rate, 2) the low sulfur fuel being burned historically resulted in low emission rates and typically remained within original equipment design specifications and capacities on an annual average basis, but 3) the sulfur content of the fuel is projected to increase significantly and exceed the capabilities of existing scrubber infrastructure. The typical dollar per ton analysis utilized by Mr. Gebhart simply evaluates the historic emissions of a unit against the unit's projected future emissions based on its permitted emissions limit to obtain the additional tons removed. In most cases evaluated by Mr. Gebhart the coal quality is not changing, the difference in the tons emitted before and after the project upgrades is equivalent to the difference in the tons of SO_2 being removed. In fact, the Company has maintained consistency with this cost effectiveness reporting methodology in its previous filings and discovery requests in this case in attempt to directly respond to questions asked. However, as a practical matter and because the coal quality is changing at the Hunter units, this type of analysis does not provide the best method for analyzing the cost effectiveness of the respective projects and appears to be causing confusion amongst the Parties to this case. To properly identify the additional tons of SO_2 removed with the new equipment, the evaluation needs to be based on the changes between historic permit emission rates and new permitted emission rates, as well as the changes in the fuel quality. Examples of this approach are provided in the Table 1 below.

Q. What are the results of the Company's cost effectiveness analyses?

A. Table 1 below provides the Company's cost effectiveness analyses for the Hunter Units 1 and 2 scrubber projects for which Mr. Gebhart recommends disallowance. The results of the Company's analyses, incorporating appropriate inputs for changes in fuel quality, further support the cost effectiveness of the scrubber projects in question.

Table 1

	Hunter 1	Hunter 2
Unit Megawatt Rating, MWn	430	430
Unit Hourly Heat Input, mmBtu/hr	4,750	4,750
Annual Capacity Factor, percent	90.0%	90.0%
Unit Annual Heat Input, mmBtu/yr @ 90% CF	37,551,600	37,551,600
Baseline Coal Btu/lb	11,208	11,208
Baseline Coal Sulfur, % (historical):	0.5	0.5
Baseline uncontrolled emission rate, lb/mmBtu	0.892	0.892
Annual uncontrolled SO_2 emissions, tons/yr	16,752	16,752
SO_2 Baseline Emission Rate, lb/mmBtu	0.16	0.16
Baseline Emissions, tons/yr	3,004	3,004
Historic tons SO2 removed	13,748	13,748
Future Coal Btu/lb	11,425	11,425
Future Coal Sulfur, %	0.767	0.767
Future Uncontrolled emission rate (lb/mmBtu)	1.343	1.343
Annual uncontrolled SO2 emissions, tons/yr	25,210	25,210
New Permitted SO_2 Rate, lb/mmBtu	0.12	0.12
Future SO_2 Emissions, tons/yr	2,253	2,253
Reduction in Future SO_2 emissions, tons/yr	751	751
Future tons SO_2 removed, tons/yr	22,957	22,957
Net increase in the tons of SO_2 removed, tons/yr	**9,209**	**9,209**
Annual Cost of Control	$9,885,000	$8,982,000
Dollar per ton estimate based on tons of SO_2 removed	$1,073	$975

Q. Has Mr. Gebhart recommended disallowance of pollution control project costs that are not included in case?

A. Yes. The most significant of which are the costs associated with the Dave Johnston Unit 3 scrubber and baghouse project which was previously placed in service and reviewed for rate base treatment under a separate Major Plant Additions docket. Notwithstanding the fact that the Company has requested recovery of only approximately $9.5 million of project close-out costs associated with this project in this case, the UAE witnesses have submitted testimony regarding their evaluation of that project in its entirety. Mr. Gebhart recommends only costs associated with the baghouse portion of that project for disallowance, and Mr. Higgins states that he has adopted Mr. Gebhart's position. However, Mr. Higgins' recommended revenue adjustment appears to reflect disallowance of what would be the equivalent revenue requirement of the entire Dave Johnston Unit 3 scrubber and baghouse project, if it were included in this case. The Company objects to the applicability of any of these analyses to this docket, disagrees with the conclusions reached, and further objects to the recommended actions. The Company is further perplexed by the inconsistency between the testimony of the two UAE witnesses mentioned above.

Q. Has Mr. Gebhart taken a similar approach with respect to the Hunter Unit 1 scrubber project?

A. Yes. The Company has requested recovery in this case of approximately $19 million of costs associated with placing in service the scrubber waste handling subcomponent of the Hunter Unit 1 scrubber project. Mr. Gebhart's testimony presents an evaluation of the costs of the Hunter Unit 1 scrubber project in its entirety, with the same flaws in his evaluation as discussed above, and recommends disallowance of the project in its entirety. The Company again objects to the applicability of these analyses to this docket, disagrees with the conclusions reached, and further objects to the recommended actions.

Planning

Q. Has the Company accounted for pollution control investments in its forward-planning cycles?

A. Yes. The Company makes every effort to identify, quantify and include forward-looking environmental compliance projects in its business planning processes and associated filings.

Q. What efforts are being taken by the Company to understand and evaluate impacts of potential future environmental regulations on the Company's business?

A. PacifiCorp and its parent, MidAmerican Energy Holdings Company, are active in current state and federal legislative and agency activities regarding environmental controls affecting virtually all emissions from coal and natural gas generating units, and other environmental issues. The Company is cognizant that some potential restrictions on greenhouse gas ("GHG") emissions could require coal (and potentially natural gas) units to adjust the depreciation lives for ratemaking purposes. The Company considers this possibility when determining whether to proceed with pollution control investments.

Q. Has the Company communicated to the Commission its knowledge and understanding of additional costs required to maintain compliance with current and anticipated likely environmental regulations?

A. Yes. As the Company becomes aware of known or anticipated likely environmental regulations, the Company begins assessment of requirements and incorporation of appropriate project completion timelines and cost estimates into its business planning processes. The Company's IRP and IRP updates filed with this Commission also include extensive discussion regarding the business planning considerations given to current and anticipated likely environmental regulations.

Q. Does the Company continue to improve its analysis of market risk associated with emerging environmental regulations, particularly risks associated with greenhouse gases?

A. Yes. In support of the Company's 2011 IRP development process, the Company incorporated System Optimizer Coal Utilization Case Studies 20-24. These case studies were designed to investigate the impacts of CO_2 cost and gas price scenarios on the Company's existing coal fleet after accounting for coal plant incremental costs. This study used new modeling functionality that enables representation of existing plant repowering and retrofitting as future resource options. Additionally, the Company acquired and used customized enhancements to the model for estimating carbon dioxide emissions and regulatory costs associated with spot market balancing sales and purchases. These case studies include capital expenditures for planned and/or ongoing pollution control equipment investments included in the Company's business plan, including mercury HAPs MACT compliance costs. Due to the timing of these case studies in 2010, the Company's preliminary capital cost estimates for compliance with the EPA's proposed coal combustion residuals (CCR) rules and Clean Water Act Section 316(b) cooling water intake rules were not incorporated. CCR compliance costs have since been incorporated into the Company's business plan, and preliminary estimates for future Clean Water Act Section 316(b) cooling water intake compliance projects are being developed and will be incorporated into the Company's next business plan cycle. These costs will be incorporated into future updates of the coal utilization case studies.

Q. Do the results of the Company's coal utilization case studies included in the 2011 IRP process result in the Company requesting accelerated depreciation treatment of pollution control investments contemplated in this case?

A. No. The results of the Company's coal utilization case studies do, however, identify certain CO_2 cost and gas price scenarios that would lead the Company to re-evaluate strategic asset planning for certain units. Re-evaluation of strategic asset planning would be vetted via the Company's depreciable life studies that are completed every five years, with the next due in 2013.

Q. Does the Company agree with Ms. Kelly's assertion that the coal utilization case studies produced no meaningful results?

A. No. The coal utilization sensitivity cases included in the Company's 2011 IRP were designed to investigate, as a modeling proof-of-concept, the impacts of CO_2 cost and gas price scenarios on the existing coal fleet. The sensitivity cases included the Company's planned and/or ongoing pollution control project investments, incorporating mercury HAPs MACT costs. As intended, the coal utilization sensitivity case studies will provide the impetus for future refinement of the modeling approach to be used for investigating coal plant operations.

Q. Will the Company continue to include System Optimizer Coal Utilization Case Studies in its IRP process?

A. Yes. The Company will continue to include and refine System Optimizer Coal Utilization Case Studies in its future IRP processes.

Q. Does the Company support Ms. Kelly's recommendation to the Commission to open a separate docket at the conclusion of this general rate case to oversee the development of a comprehensive analysis of any significant new coal plant investments?

A. No. The Company's IRP proceedings conducted in all six of the states served by the Company provides the process to address ongoing investment in the Company's coal units. As noted above, the Company's intent is to continue to include and refine its modeling and evaluation tools in this regard. As evidenced by the testimony, exhibits and extensive discovery provided by the Company in this docket, the Company will continue to apply least cost principals to its pollution control investments and offer comparisons of compliance alternatives including retrofitted coal fueled generation units to other generation resource classes, such as combined-cycle natural gas fueled generation and conversion of coal-fueled units to natural gas. Establishing a separate docket to oversee the development of said analyses would be duplicative.

Q. Do the pollution control investments presented in this case also support compliance with anticipated likely regulations?

A. Yes. In many cases the investments are also expected to support compliance with anticipated likely regulations as currently proposed. Confidential Exhibit

RMP___(CAT-1R) attached to this testimony provides an overview of anticipated likely regulations with which the projects presented in this case are anticipated to support compliance.

Q. Has the Company presented pollution control investments in this case based on anticipated regulations that do not exist, may never be implemented, and if implemented may require technologies other than those installed by the Company?

A. No. As discussed above, the Company maintains that the pollution control investments presented in this case are required to comply with existing regulations being administered by the respective state departments of environmental quality.

Q. Does the Company agree that Dr. Fisher has accurately forecasted the future capital investment obligations associated with emerging environmental regulations that the Company may be facing through the 2020 timeframe?

A. No. The Company believes that Dr. Fisher has taken a generalized view of emerging environmental regulations without any real certainty of agency action. Where Dr. Fisher's forecast falls short is with respect to detailed evaluation of the Company's individual units and installations as they may be affected by the emerging environmental regulations considered.

Q. Do you agree with Dr. Fisher's discussion regarding selective catalytic reduction ("SCR") capital investments?

A. No. With respect to the SCR investments identified by Dr. Fisher for Dave Johnston Units 3 and 4, Naughton Units 1 through 3, Wyodak, Jim Bridger Units

1 through 4, Hunter Units 1 through 3, and Huntington Units 1 and 2, all with in-service dates of 2015 (except Jim Bridger Unit 4 which is identified with a 2016 in-service date), the Company does not believe that Dr. Fisher's plan represents a likely outcome. The costs that Dr. Fisher proposed are generally understated and the proposed installation schedule is overly optimistic, highly inefficient and unfeasible. EPA is not expected to take action on the recently submitted Utah and Wyoming Regional Haze state implementation plans ("SIPs") until 2012, at the earliest. Not accounting for potential appeals of final EPA action, if EPA requires additional SCR as part of its approval of these SIPs, federal Regional Haze regulations will require installation "as expeditiously as practicable", but not later than five years after EPA's approval of the SIPs. Dr. Fisher's schedule for installation of SCR at 13 facilities by 2015 and one in 2016 is not consistent with the Regional Haze Rules, and installation of 13 SCR in approximately 3 ½ years is in no way "practicable."

In addition, in Wyoming, the EPA is aware of the settlement reached with respect to the timing of the Naughton and Jim Bridger SCRs following the Company's recent appeal of BART permits for those units. That settlement does not call for the installation of SCR at the identified Wyoming units by 2015 as suggested by Dr. Fisher, but instead requires installation of SCR at only five units on a gradual basis over time beginning in 2014 and ending in 2022. This settlement reflects the expectation of both PacifiCorp and the Wyoming Department of Environmental Quality and is far more indicative of the timing for installing SCR equipment than Dr. Fisher's speculation. The Company's out-year business plan (beyond 2020) currently includes SCRs for three Utah units; however, the Company has not been compelled to commit to those projects via permit applications or other agency action. The Company will continue to evaluate such investment plans with the appropriate inputs and considerations. The Company will also remain engaged in the EPA SIP review process with the intent of effectuating outcomes in the best interests of its customers and stakeholders. The Company firmly believes that its current commitments regarding SCR installations meet the letter and intent of the Regional Haze Rules, including guidance provided by the EPA Appendix Y of 40 CFR Part 51.

Q. Do you agree with Dr. Fisher's discussion regarding baghouse capital investments?

A. No. With respect to the baghouse investments identified by Dr. Fisher for Naughton Units 1 and 2 and Jim Bridger Units 1 through 4 with various costs and in-service dates through 2016, Dr. Fisher's plan does not represent a likely outcome. Dr. Fisher identifies the underlying driver for each of the baghouses as maximum achievable control technology ("MACT") compliance. Presumably, Dr. Fisher's MACT reference is to the EPA's recently proposed non-mercury metallic hazardous air pollutants ("HAPs") MACT rules, and the associated surrogate particulate matter emissions compliance limits. Based on the Company's evaluation of the proposed non-mercury metallic HAPs MACT rules at the facilities identified, the Company expects to be able to comply with the surrogate particulate matter emissions limit at each facility with existing equipment; therefore, not requiring the baghouse investments Dr. Fisher identifies. In addition, based on recently completed control technology demonstration testing, the Company also expects to be able to comply with mercury HAPs MACT rules via activated carbon injection ("ACI") and supplemental reagent injection, as may be required. Once again, not requiring the baghouse investments Dr. Fisher identifies. The Company's ACI plans are discussed further below. The baghouse cost estimates provided by Dr. Fisher reflect costs that are not necessary for the reasons discussed above.

Q. Do you agree with Dr. Fisher's observations regarding ACI investments?

A. No. With respect to the ACI investments identified by Dr. Fisher with various in-service dates and costs, the Company has incorporated a similar compliance plan for mercury emission into its business planning process; however, specific project costs and schedules are only generally aligned with Dr. Fisher's proposal. The Company's plan deviates most significantly from Dr. Fisher's proposal at Hunter and Huntington, where the Company does not anticipate needing ACI systems to achieve mercury HAPs MACT compliance, as currently proposed.

Q. Do you agree with Dr. Fisher's observations regarding coal ash remediation investments?

A. No. With respect to the coal ash remediation line item identified by Dr. Fisher with various in-service dates through 2017 and no cost estimates, the Company has incorporated preliminary coal combustion residuals ("CCR") compliance plans that are generally aligned with the timing proposed into its business planning process. Management of the CCR is an integral part of the Company's operations. With respect to Dr. Fisher's correlation of future CCR compliance costs with the Company's decisions to continue to invest in its coal fueled generation assets, it is important to note that the Company will be faced with certain CCR storage, handling, and long-term management costs at its existing facilities whether the facilities continue to operate or not. Therefore, the Company continually updates its CCR-related costs and asset retirement obligations. In response to the recently proposed EPA rulemaking regarding CCR, the Company has updated its CCR-related costs and asset retirement obligations on a preliminary basis to incorporate proposed Subtitle D or near-Subtitle D infrastructure requirements, which will serve as a proxy until such time as EPA responds to the recently completed public comment period for CCR regulations. Dr. Fisher's implication that the Company has not included such considerations into its business planning process is inaccurate.

Q. Do you agree with Dr. Fisher's observations regarding effluent and remediation investments?

A. No. With respect to the effluent and impingement remediation line items identified by Dr. Fisher with various in-service dates through 2018 and no cost estimates other than for the proposed cooling tower addition at Dave Johnston Unit 3, the Company is in the process of evaluating these recently proposed rules. However, based on the Company's past investigations of its facilities, including Dave Johnston Unit 3, investments associated with compliance in these areas are expected to be limited and are not expected to result in investments in cooling tower additions, as Dr. Fisher speculates.

Q. Please provide a summary of your testimony.

A. The Company's pollution control projects included in this case and their timing appropriately balance compliance with environmental regulations, including Regional Haze programs administered by the states of Utah and Wyoming, with the costs and other concerns of our customers. The projects are required to comply with existing regulations, including stand-alone requirements in state implementation plans, BART permits and construction permits enforceable by the laws of the respective states, independent of whether EPA has approved the respective state implementation plans. The Company's considerations when making pollution control investments include evaluation of state and federal environmental regulatory requirements and associated compliance deadlines, review of emerging environmental regulations and rulemaking, and analyses of alternate compliance options. Considerations also include ongoing compliance with existing operating requirements, fuel supply flexibility, equipment end of life considerations, and operational efficiencies. The Company's analyses completed to date demonstrate that maintaining the ability to operate the coal-fueled units included in this case by retrofitting them with the pollution control equipment represents the least-cost option for our customers. PacifiCorp has compared the cost of retrofitted coal fueled generation units to other generation resource classes, including combined-cycle natural gas fueled generation and conversion of coal-fueled units to natural gas.

Q. Does this conclude your rebuttal testimony?

A. Yes.