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**BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

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| **IN THE MATTER OF THE** | ) | |
| **APPLICATION OF ROCKY** | ) | **CASE NO. PAC-E-11-12** |
| **MOUNTAIN POWER FOR** | ) | |
| **APPROVAL OF CHANGES TO ITS** | ) | **Direct Testimony of Chad A. Teply** |
| **ELECTRIC SERVICE SCHEDULES** | ) | |
| **AND A PRICE INCREASE OF $32.7** | ) | |
| **MILLION, OR APPROXIMATELY** | ) | |
| **15.0 PERCENT** | ) | |

**ROCKY MOUNTAIN POWER**

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**CASE NO. PAC-E-11-12**

**May 2011**

**Q. Please state your name, business address and position with PacifiCorp dba Rocky Mountain Power (the "Company").**

A. My name is Chad A. Teply. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah. My position is vice president of resource development and construction for PacifiCorp Energy. I report to the president of PacifiCorp Energy. Both Rocky Mountain Power and PacifiCorp Energy are divisions of PacifiCorp.

**Qualifications**

**Q. Please describe your education and business experience.**

A. I have a Bachelor of Science Degree in Mechanical Engineering from South Dakota State University. I joined MidAmerican Energy Company in November 1999 and held positions of increasing responsibility within the generation organization, including the role of project manager for the 790-megawatt Walter Scott Energy Center Unit 4 completed in June 2007. In April 2008, I moved to Northern Natural Gas Company as senior director of engineering. In February 2009, I joined the PacifiCorp team as vice president of resource development and construction, at PacifiCorp Energy. In my current role, I have responsibility for development and execution of major resource additions and major environmental projects.

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

A. The purpose of my testimony is to:

- provide the Commission with information supporting the prudence of capital investments in pollution control equipment, generation plant, and hydro projects being placed in service during the test period; and

- support the prudence of incremental generation operations and maintenance costs associated with certain new resources, new pollution control equipment, and other generation fleet operational changes impacting this case.

**Background**

**Q. Please provide a general description of the pollution control equipment and additional capital investments being placed in service, and the benefits gained from the investments.**

A. The pollution control equipment investments included in this case primarily result in the reduction of sulfur dioxide ("$SO_2$"), nitrogen oxides ("$NO_x$"), mercury ("Hg"), and particulate matter ("PM") emissions from the retrofitted Naughton Unit 2, Wyodak, Huntington Unit 1, Hunter Unit 2 and Jim Bridger Unit 3 facilities. These investments are required to comply with current, proposed, and probable environmental regulations as further discussed in the direct testimony of Ms. Cathy S. Woollums. These investments constitute approximately 60 percent of the Company's capital investments placed in service or projected to be placed in service from January 2011 through December 2011.

Hydro generation plant investments, which constitute approximately 4 percent of the Company's capital investments placed in service or projected to be placed in service from January 2011 through December 2011, are primarily new license implementation measures required by the Federal Energy Regulatory Commission to allow continued operation of these low-cost generation assets.

The generation plant turbine upgrade investment enhances the Company's overall generation capability and cycle efficiency without increasing emissions for the large thermal unit that receives this equipment.

Other generation plant investments during the test year support asset safety, reliability, and cost effectiveness via reduced risk of equipment and component failures, enhanced control systems, and improved security provisions.

**Q. Please describe the primary environmental regulation requiring the pollution control investments included in this case.**

A. Through the 1977 amendments to the Clean Air Act, Congress set a national goal for visibility to remedy impairment from manmade emissions in designated national parks and wilderness areas; this goal resulted in development of the Regional Haze Rules, adopted in 2005 by the U.S. Environmental Protection Agency ("EPA"). The first phase of these rules trigger Best Available Retrofit Technology ("BART") reviews for all coal-fired generation facilities built between 1962 and 1977 that emit at least 250 tons of visibility-impairing pollution per year. Visibility-impairing pollutants include $SO_2$, $NO_x$ and PM. The direct testimony of Ms. Woollums includes additional discussion regarding the Regional Haze Rules and other environmental drivers behind the pollution control investments included in this case.

**Q. Please describe the efforts taken to evaluate available control technologies.**

A. As part of the BART review of each facility, the Company evaluated several technologies on their ability to economically achieve compliance and support an integrated approach to control criteria pollutants (*e.g.* $SO_2$, $NO_x$, and PM for the facility), if it were to continue to operate and to burn coal. The BART analyses reviewed available retrofit emission control technologies and their associated performance and cost metrics. Each of the technologies was reviewed against its ability to meet a presumptive BART emission limit based on technology and fuel characteristics. The BART analyses outlined the available emission control technologies, the cost for each and the projected improvement in visibility which can be expected by the installation of the respective technology. For each unit or source subject to BART, the state environmental regulatory agencies identify the appropriate control technology to achieve what the air quality regulators determine are cost-effective emission reductions. Once the appropriate BART technology was identified, the Company moved forward with its competitive bidding process to evaluate and ultimately select the preferred provider for the projects.

**Q. Does the Company focus solely on environmental compliance factors when determining which capital investments to make?**

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

**Q. What other factors does the Company consider?**

A. Factors such as ongoing compliance with existing operating requirements, fuel supply flexibility, equipment end of life considerations, and operational efficiencies are also factors typically included in the Company's investment decisions.

**Q. How has ongoing compliance with existing operating requirements factored into planning of pollution control investments?**

A. The Huntington Unit 1 and Hunter Unit 2 baghouse projects and the waste handling phases of the Huntington Unit 1 and Hunter Unit 2 scrubber projects presented in this case are good examples of how ongoing compliance with current regulations factors into the company's pollution control investment planning process. The addition of the baghouse will significantly reduce PM emissions and improve compliance with existing opacity standards. The scrubber waste handling systems will ensure that the final waste product will not contain any free liquids and can properly be disposed of in the onsite landfill.

**Q. How has fuel supply flexibility factored into planning of pollution control investments?**

A. The Hunter Unit 2 scrubber project is a good example of how fuel supply flexibility has factored into the Company's pollution control investment planning process. As the Company contemplated BART requirements for Hunter Units 1 and 2, pollution control equipment that would meet required emission limits and would permit utilization of coal with higher coal sulfur content was evaluated. The ability to fuel the Hunter units on coal with higher sulfur content while meeting new emission limits will help to maintain competitive fuel and generation costs at this facility.

**Q. How have existing pollution control equipment end of life replacement considerations factored into planning of new pollution control investments?**

A. The replacement of various scrubber system elements at Hunter Unit 2 is an example. These elements include scrubber vessel work scope, scrubber recycle pump replacements, and scrubber reagent injection nozzle replacements, as well as the scrubber reagent preparation system replacement. By planning the Hunter Unit 2 scrubber project tie-in to coincide with a planned maintenance outage cycle for the unit, the project was 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 considerations factored into planning of pollution control investments?**

A. Operational 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 Unit 2 scrubber projects are two key examples of the Company's efforts to improve operational efficiencies. These projects result in the installation of scrubber waste dewatering equipment that eliminates the manual management of fly ash blending processes. Thus, in addition to addressing system capacity concerns and maintaining waste disposal compliance, these projects improve operational efficiencies allowing plant staff to focus on other operational responsibilities.

**Q. What process is in place to explore ongoing investment in the Company's coal units?**

A. The existing integrated resource planning ("IRP") process conducted across the six states served by the Company provides the process to analyze and address ongoing investment in the Company's coal units versus alternatives including retirement and replacement and repowering. Future IRPs will increasingly focus upon the complexity in balancing factors such as:

(1) pending environmental regulations and requirements to reduce emissions in addition to addressing waste disposal and water quality concerns;

(2) avoidance of excessive reliance on any one generation technology;

(3) costs and trade-offs of various resource options including energy efficiency, demand response programs, and renewable generation;

(4) state-specific energy policies, resource preferences, and economic development efforts;

(5) the need for additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and

(6) managing the impact on customer rates.

**Q. Has the Company compared 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 developed Confidential Exhibit No. 22 to compare the cost of retrofitted coal fueled generation units to other generation resource classes.

Confidential Exhibit No. 22 presents the 2009 embedded generation bus bar cost per megawatt-hour differences of the various generation resources within the Company's generation fleet, including re-powered and combined-cycle natural gas fueled generation. Confidential Exhibit No. 23 provides the incremental revenue requirement associated with the pollution control equipment retrofits 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 or less than the capital cost to build a new combined cycle natural gas generation unit. However, fuel costs of a combined cycle natural gas unit will overwhelm capital cost competitiveness 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.

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 Wyoming, 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 No. 24 and Confidential Exhibit No. 25 provide the results of said analyses at various points in time and with various $CO_2$ costs and market pricing assumptions. Confidential Exhibit No. 24 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 then current $CO_2$ cost and market pricing assumptions. Confidential Exhibit No. 25 provides a PVRR(d) view of the units that received the pollution control investments on a going-forward basis, utilizing $CO_2$ cost and market pricing assumptions 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. The PVRR(d) 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 No. 26 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?**

A. Yes. In assessing when and whether to proceed with pollution control investments, the Company has considered cost effectiveness of reasonable options.

Measures of capital cost on a dollars per kilowatt basis have been reviewed during studies of alternatives, as well as the cost to remove a ton of a pollutant, which is applied specifically as part of the BART determination process. Recently, BART determinations issued by the EPA and other state agencies for $SO_2$ and $NO_x$ emission control projects have demonstrated that removal costs of up to $7,500 per ton are not considered cost prohibitive. PM 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 PM removal equipment. It should also be noted that when ongoing compliance and/or equipment end-of-life issues must be addressed, the dollar per incremental ton removed evaluation is not applicable. A listing of representative costs per ton removed for the pollution control projects presented in this case is included in Confidential Exhibit No. 27.

**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 planning processes.

**Q. Is the Company obligated to install pollution controls required by state permits, regardless of whether final EPA review and approval of the respective regional haze state implementation plans remains pending?**

A. Yes. The BART permits and construction permits issued by the respective state agencies for the pollution control investments contemplated in this case include stand-alone requirements enforceable by the laws of the respective states. These requirements are enforceable independent of whether EPA has approved the respective state implementation plans.

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

A. Yes. The pollution control investments in this case are required to comply with existing regulations including Regional Haze Rules, National Ambient Air Quality Standards, the Regional $SO_2$ Milestone and Backstop Trading Program developed in alignment with existing federal regulations and administered in Utah and Wyoming, state issued construction and operating permits, and state implementation plans. Exhibit No. 28 provides an overview of existing regulations with which the projects will be in compliance.

**Q. Do the pollution control investments 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. Exhibit No. 28 provides an overview of anticipated likely regulations with which the projects presented in this case are anticipated to support compliance.

**Q. Are the 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. The pollution control investments in this case are required to comply with existing regulations being administered by the respective state departments of environmental quality.

**Q. Does the Company anticipate that final EPA approval of the respective state implementation plans will require alternate pollution control equipment to be installed, making the equipment contemplated in this case obsolete?**

A. No. While it is possible that the EPA will require more stringent emission limits, any such requirement will be in addition to – not in place of – the pollution control technology selections completed to date, which apply best available retrofit technology, comply with existing state and federal regulations, and support Regional Haze Rule objectives. The Company also incorporates into its pollution control equipment contract specifications design considerations intended to provide appropriate levels of operating margin, equipment redundancy, and system maintainability and reliability provisions to support an expected range of process inputs, operating conditions, and system performance. Although the Company cannot predict future pollution control regulations and associated emissions limits, the Company does take steps to procure a prudent level of design flexibility to accommodate potential changes in system performance requirements, where practical.

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

A. Yes. As the Company becomes aware of known or anticipated 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 environmental regulations.

**Q. Has the Company developed other information regarding the Company's overall emission reduction plans through 2023?**

A. Yes. The Company has provided additional information including an overview of the Company's long-term emission reduction commitment, project installation schedules and compliance deadlines, emission reduction priorities, anticipated customer impacts, and brief descriptions of other environmental initiatives that are also expected to impact future operating costs of the Company in its recent filings in other states. A copy of this additional information is provided for reference in Exhibit No. 29.

**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 data sets will be incorporated into future updates of the coal utilization case studies. Exhibit No. 29, Table 1 lists the Company's planned air emissions related pollution control projects included in the case studies, with the exception of activated carbon injection projects for mercury emissions control.

**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. 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. Has the Company installed the pollution control investments in an efficient manner?**

A. Yes. As further discussed in Exhibit No. 29, 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. Does the Company believe that 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 compliance with state issued permits, state implementation plans, and regional $SO_2$ milestones and backstop trading programs.

**Customer Considerations**

**Q. What are the benefits to customers of installing the pollution control equipment and why should Idaho customers pay the costs related to this project?**

A. Customers directly benefit from the continued availability of low-cost generation produced at the facilities while also achieving environmental improvements from these resources, resulting in cleaner air. In addition, the tie-in of these necessary controls is being accomplished during planned maintenance outages, as opposed to scheduling separate outages for this work, which reduces replacement power costs. The Company has 10 BART-eligible units in Wyoming and four in Utah. The BART controls for each of these units must be installed as expeditiously as possible, but no later than five years from the date the respective SIPs are approved and prior to the compliance dates specified in the permits

Postponing installation of the pollution control equipment included in this case to later planned maintenance outages would make it virtually impossible for the Company to effectively ensure that all of its affected units meet compliance deadlines and would place the Company at risk of not having access to necessary capital, materials, and labor while attempting to perform these major equipment installations in a compressed timeframe. As the deadlines for environmental requirements across the country draw closer, the demand for equipment and skilled labor is likely to increase, making timely compliance more difficult without incurring significant additional cost.

**Description of Pollution Control Investment Projects**

**Q. Please describe the Naughton Unit 2 scrubber addition project and associated equipment.**

A. The scrubber addition project at the Naughton Unit 2 power plant includes the installation of $SO_2$ controls. The capital investment for the project being placed in service during the test period is approximately $152 million. Construction began in 2010, and the project is expected to be placed in service by November 2011. The new pollution control equipment will be tied into the existing unit during a scheduled plant maintenance outage. The project will install a flue gas desulfurization ("FGD") system. The FGD system injects reagent slurry containing sodium carbonate and sodium bicarbonate in the top of an absorber vessel ("scrubber") with a network of spray nozzles. The distribution of spray nozzles and trays causes the sodium carbonate slurry to intermix with the flue gas passing through the absorber vessel. The $SO_2$ in the flue gas reacts with the sodium carbonate in the slurry to form waste slurry of sodium sulfite and sodium sulfate. The liquid waste slurry is then captured and transported to a scrubber waste pond for disposal. The scrubber waste will ultimately be dewatered and retained in a closed and capped scrubber waste cell on the Naughton plant site.

Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork and a new chimney, sodium carbonate slurry reagent preparation systems, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

**Q. Is the Company also installing scrubber facilities at the Naughton Unit 1 power plant?**

A. Yes. The Naughton Unit 1 scrubber project is being constructed concurrently with the Naughton Unit 2 scrubber project, but on a different schedule. The description of the Naughton Unit 1 scrubber project is for the most part identical to that provided above.

**Q. Will the Naughton Unit 1 scrubber addition project also be placed in service during the test period used in this case?**

A. No. The Naughton Unit 1 scrubber project is expected to be placed in service during the next planned major maintenance outage for that unit, expected to be complete by May 2012. The planned major maintenance outages for the Company's generation assets are scheduled on a control area basis, considering optimal frequency between overhauls and to minimize the number of major units off line at any one time. The Company completed its most recent overhaul to Naughton Unit 1 in 2008 and is scheduled for its next overhaul in the spring of 2012. The Company's intent in establishing the tie-in schedules for the Naughton Unit 1 and Naughton Unit 2 pollution control equipment was to balance the aggregated construction costs and schedules for the pollution control equipment projects against the established planned maintenance overhaul schedules, work plans, and budgets for the respective units.

**Q. Are common facilities costs associated with the Naughton Unit 1 and Naughton Unit 2 scrubber addition projects included in this case?**

A. Yes. The cost of all common facilities that are required to be placed in service to allow prudent operation of either unit's new emission control equipment are incorporated into the Naughton Unit 2 capital investment being placed in service by November 2011. Common facilities include reagent preparation, waste disposal, electrical supply, and ancillary utility systems, as well as site preparation and the chimney.

**Q. Please describe the Wyodak power plant stand-alone bag house project and associated equipment.**

A. A stand-alone bag house was installed at the Wyodak power plant for control of PM, $SO_2$, and Hg emissions consistent with requirements. In order to increase the $SO_2$ removal efficiency of the unit above 90 percent as required to comply with environmental requirements, a bag house must be utilized in conjunction with the existing dry spray dryer absorbers ("SDAs"). Without a bag house, the best $SO_2$ removal efficiency a SDA on the unit can achieve with Wyodak coal is between 70 and 80 percent. Adding the bag house is necessary to achieve the permitted $SO_2$ removal requirements.

The Company's share of the capital investment for the Wyodak bag house project being placed in service during the test period is approximately $104 million. Construction began in 2010, and the project was placed in service at the end of April 2011. The new pollution control equipment was tied into the existing unit during a scheduled plant maintenance outage.

The bag house captures PM from the flue gas stream as it passes through the bag house and will improve the unit's efficiency in removing $SO_2$ and Hg from the flue gas. The dry particulate waste stream containing both fly ash and scrubber waste will then be transported to an ash collection pond on adjacent coal mine property for disposal.

Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

**Q. Please describe the Huntington Unit 1 power plant scrubber project, and associated equipment.**

A. The scrubber project at the Huntington Unit 1 power plant provides required $SO_2$ controls for the unit, as well as a new scrubber waste material handling system and conversion of the chimney to wet operation. The new waste handling equipment will be designed to manage the increase in waste product from the higher removal efficiency and increased throughput of the scrubber.

The capital investment for the scrubber waste material handling project being placed in service during the test period is approximately $29 million. Construction began in 2010, and the scrubber waste handling project was placed in service in March 2011. Installation of the waste handling portion of the project will be completed with the plant in service. The portion of the Hunter 2 scrubber project that resulted in increased flue gas desulfurization ("FGD") system slurry delivery system capacity, by replacing recycle pumps and reagent supply piping and appurtenances, was placed in service prior to the test period for this docket. The wet stack conversion was also completed prior to the test period.

The scrubber waste material handling project includes forced oxidation