

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

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

8 **Qualifications**

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

10 A. I have a Bachelor of Science Degree in Mechanical Engineering from South
11 Dakota State University. I joined MidAmerican Energy Company in November
12 1999 and held positions of increasing responsibility within the generation
13 organization, including the role of project manager for the 790-megawatt Walter
14 Scott Energy Center Unit 4 completed in June 2007. In April 2008, I moved to
15 Northern Natural Gas Company as senior director of engineering. In February
16 2009, I joined the PacifiCorp team as vice president of resource development and
17 construction, at PacifiCorp Energy. In my current role, I have responsibility for
18 development and execution of major resource additions and major environmental
19 projects.

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

21 A. The purpose of my testimony is to:
22 • provide the Commission with information supporting the prudence of
23 capital investments in pollution control equipment, generation plant, and

1 hydro projects being placed in service during the test period; and
2 • support the prudence of incremental generation operations and
3 maintenance costs associated with certain new resources, new pollution
4 control equipment, and other generation fleet operational changes
5 impacting this case.

6 **Background**

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

10 A. The pollution control equipment investments included in this case primarily result
11 in the reduction of sulfur dioxide (“SO₂”), nitrogen oxides (“NO_x”), mercury
12 (“Hg”), and particulate matter (“PM”) emissions from the retrofitted Naughton
13 Unit 2, Wyodak, Huntington Unit 1, Hunter Unit 2 and Jim Bridger Unit 3
14 facilities. These investments are required to comply with current, proposed, and
15 probable environmental regulations as further discussed in the direct testimony of
16 Ms. Cathy S. Woollums. These investments constitute approximately 60 percent
17 of the Company’s capital investments placed in service or projected to be placed
18 in service from January 2011 through December 2011.

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

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

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

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

9 A. Through the 1977 amendments to the Clean Air Act, Congress set a national goal
10 for visibility to remedy impairment from manmade emissions in designated
11 national parks and wilderness areas; this goal resulted in development of the
12 Regional Haze Rules, adopted in 2005 by the U.S. Environmental Protection
13 Agency (“EPA”). The first phase of these rules trigger Best Available Retrofit
14 Technology (“BART”) reviews for all coal-fired generation facilities built
15 between 1962 and 1977 that emit at least 250 tons of visibility-impairing pollution
16 per year. Visibility-impairing pollutants include SO₂, NO_x and PM. The direct
17 testimony of Ms. Woollums includes additional discussion regarding the Regional
18 Haze Rules and other environmental drivers behind the pollution control
19 investments included in this case.

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

21 A. As part of the BART review of each facility, the Company evaluated several
22 technologies on their ability to economically achieve compliance and support an
23 integrated approach to control criteria pollutants (*e.g.* SO₂, NO_x, and PM for the

1 facility), if it were to continue to operate and to burn coal. The BART analyses
2 reviewed available retrofit emission control technologies and their associated
3 performance and cost metrics. Each of the technologies was reviewed against its
4 ability to meet a presumptive BART emission limit based on technology and fuel
5 characteristics. The BART analyses outlined the available emission control
6 technologies, the cost for each and the projected improvement in visibility which
7 can be expected by the installation of the respective technology. For each unit or
8 source subject to BART, the state environmental regulatory agencies identify the
9 appropriate control technology to achieve what the air quality regulators
10 determine are cost-effective emission reductions. Once the appropriate BART
11 technology was identified, the Company moved forward with its competitive
12 bidding process to evaluate and ultimately select the preferred provider for the
13 projects.

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

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

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

22 A. Factors such as ongoing compliance with existing operating requirements, fuel
23 supply flexibility, equipment end of life considerations, and operational

1 efficiencies are also factors typically included in the Company's investment
2 decisions.

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

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

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

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

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

3 A. The replacement of various scrubber system elements at Hunter Unit 2 is an
4 example. These elements include scrubber vessel work scope, scrubber recycle
5 pump replacements, and scrubber reagent injection nozzle replacements, as well
6 as the scrubber reagent preparation system replacement. By planning the Hunter
7 Unit 2 scrubber project tie-in to coincide with a planned maintenance outage cycle
8 for the unit, the project was able to replace equipment and components that had
9 exhausted their useful life, and at the same time address system capacity and
10 compliance requirements.

11 **Q. How have operational considerations factored into planning of pollution**
12 **control investments?**

13 A. Operational considerations are included in the technical specifications for each of
14 the Company's pollution control projects. The material handling phases of the
15 Huntington Unit 1 and Hunter Unit 2 scrubber projects are two key examples of
16 the Company's efforts to improve operational efficiencies. These projects result in
17 the installation of scrubber waste dewatering equipment that eliminates the
18 manual management of fly ash blending processes. Thus, in addition to
19 addressing system capacity concerns and maintaining waste disposal compliance,
20 these projects improve operational efficiencies allowing plant staff to focus on
21 other operational responsibilities.

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

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

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

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

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

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

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

18 (6) managing the impact on customer rates.

19 **Q. Has the Company compared the cost of continued operation of the retrofitted**
20 **coal fueled generation units contemplated in this case to its other generation**
21 **sources, including natural gas fueled generation?**

22 A. Yes. The Company has developed Confidential Exhibit No. 22 to compare the
23 cost of retrofitted coal fueled generation units to other generation resource classes.

1 Confidential Exhibit No. 22 presents the 2009 embedded generation bus bar cost
2 per megawatt-hour differences of the various generation resources within the
3 Company's generation fleet, including re-powered and combined-cycle natural
4 gas fueled generation. Confidential Exhibit No. 23 provides the incremental
5 revenue requirement associated with the pollution control equipment retrofits in
6 this case on a dollars per megawatt-hour basis adjusted to 2009 dollars.

7 In general terms, the capital cost on a dollars per megawatt basis to retrofit
8 pollution controls on existing coal fueled generation is approximately the same or
9 less than the capital cost to build a new combined cycle natural gas generation
10 unit. However, fuel costs of a combined cycle natural gas unit will overwhelm
11 capital cost competitiveness when compared to a retrofitted coal fueled facility.
12 Natural gas on a dollars per million Btu basis is approximately triple the cost of
13 coal, and even when considering the efficiency differences, the cost of electricity
14 generated by an emission controlled coal fueled facility will be significantly less
15 than the cost of electricity from a new combined cycle.

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

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

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

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

12 A. Yes. The Company has developed economic analyses that provide an overview of
13 the PVRR(d) benefits associated with its pollution control investments, with
14 consideration given to potential CO₂ costs and resulting market pricing
15 assumptions. Confidential Exhibit No. 24 and Confidential Exhibit No. 25
16 provide the results of said analyses at various points in time and with various CO₂
17 costs and market pricing assumptions. Confidential Exhibit No. 24 provides a
18 PVRR(d) view of the projects presented in this case at the time of planning and
19 approval of the pollution control investments, utilizing then current CO₂ cost and
20 market pricing assumptions. Confidential Exhibit No. 25 provides a PVRR(d)
21 view of the units that received the pollution control investments on a going-
22 forward basis, utilizing CO₂ cost and market pricing assumptions and the System
23 Optimizer Coal Utilization Case Studies referenced below. These PVRR(d)

1 analyses provide positive results for the various scenarios presented and further
2 demonstrate prudence of the pollution control investments. The PVRR(d)
3 analyses also offer insight into the potential impacts of various CO₂ cost and
4 market pricing scenarios on investment recovery periods.

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

8 A. Yes. The Company has developed economic analyses intended to provide an
9 overview of the PVRR(d) benefits associated with its pollution control
10 investments, with consideration given to potential CO₂ costs and resulting market
11 pricing assumptions, versus natural gas repowering scenarios. Confidential
12 Exhibit No. 26 provides the PVRR(d) results of said natural gas repowering
13 analyses. The results of these PVRR(d) analyses provide positive results for the
14 various scenarios presented and further demonstrate prudence of the pollution
15 control investments presented in this case, and also offer insight into the potential
16 impacts of various CO₂ cost and market pricing scenarios on investment recovery
17 periods.

18 **Q. Does the Company believe that it has appropriately assessed the cost**
19 **effectiveness of the pollution control investments?**

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

23 Measures of capital cost on a dollars per kilowatt basis have been

1 reviewed during studies of alternatives, as well as the cost to remove a ton of a
2 pollutant, which is applied specifically as part of the BART determination
3 process. Recently, BART determinations issued by the EPA and other state
4 agencies for SO₂ and NO_x emission control projects have demonstrated that
5 removal costs of up to \$7,500 per ton are not considered cost prohibitive. PM
6 emission reductions cannot typically be compared to this same cost per ton
7 removal standard since the incremental emissions improvement will be much
8 smaller due to the relatively high removal efficiency level of existing PM removal
9 equipment. It should also be noted that when ongoing compliance and/or
10 equipment end-of-life issues must be addressed, the dollar per incremental ton
11 removed evaluation is not applicable. A listing of representative costs per ton
12 removed for the pollution control projects presented in this case is included in
13 Confidential Exhibit No. 27.

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

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

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

21 A. Yes. The BART permits and construction permits issued by the respective state
22 agencies for the pollution control investments contemplated in this case include
23 stand-alone requirements enforceable by the laws of the respective states. These

1 requirements are enforceable independent of whether EPA has approved the
2 respective state implementation plans.

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

5 A. Yes. The pollution control investments in this case are required to comply with
6 existing regulations including Regional Haze Rules, National Ambient Air
7 Quality Standards, the Regional SO₂ Milestone and Backstop Trading Program
8 developed in alignment with existing federal regulations and administered in Utah
9 and Wyoming, state issued construction and operating permits, and state
10 implementation plans. Exhibit No. 28 provides an overview of existing
11 regulations with which the projects will be in compliance.

12 **Q. Do the pollution control investments also support compliance with**
13 **anticipated likely regulations?**

14 A. Yes. In many cases the investments are also expected to support compliance with
15 anticipated likely regulations as currently proposed. Exhibit No. 28 provides an
16 overview of anticipated likely regulations with which the projects presented in
17 this case are anticipated to support compliance.

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

21 A. The pollution control investments in this case are required to comply with existing
22 regulations being administered by the respective state departments of
23 environmental quality.

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

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

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

20 A. Yes. As the Company becomes aware of known or anticipated environmental
21 regulations, the Company begins assessment of requirements and incorporation of
22 appropriate project completion timelines and cost estimates into its business
23 planning processes. The Company's IRP and IRP updates filed with this

1 Commission also include extensive discussion regarding the business planning
2 considerations given to current and anticipated environmental regulations.

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

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

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

15 A. Yes. In support of the Company's 2011 IRP development process, the Company
16 incorporated System Optimizer Coal Utilization Case Studies 20-24. These case
17 studies were designed to investigate the impacts of CO₂ cost and gas price
18 scenarios on the Company's existing coal fleet after accounting for coal plant
19 incremental costs. This study used new modeling functionality that enables
20 representation of existing plant repowering and retrofitting as future resource
21 options. Additionally, the Company acquired and used customized enhancements
22 to the model for estimating carbon dioxide emissions and regulatory costs
23 associated with spot market balancing sales and purchases. These case studies

1 include capital expenditures for planned and/or ongoing pollution control
2 equipment investments included in the Company's business plan, including
3 mercury HAPs MACT compliance costs. Due to the timing of these case studies
4 in 2010, the Company's preliminary capital cost estimates for compliance with
5 the EPA's proposed coal combustion residuals ("CCR") rules and Clean Water
6 Act Section 316(b) cooling water intake rules were not incorporated. CCR
7 compliance costs have since been incorporated into the Company's business plan,
8 and preliminary estimates for future Clean Water Act Section 316(b) cooling
9 water intake compliance projects are being developed and will be incorporated
10 into the Company's next business plan cycle. These data sets will be incorporated
11 into future updates of the coal utilization case studies. Exhibit No. 29, Table 1
12 lists the Company's planned air emissions related pollution control projects
13 included in the case studies, with the exception of activated carbon injection
14 projects for mercury emissions control.

15 **Q. Do the results of the Company's coal utilization case studies included in the**
16 **2011 IRP process result in the Company requesting accelerated depreciation**
17 **treatment of pollution control investments contemplated in this case?**

18 A. No. The results of the Company's coal utilization case studies do, however,
19 identify certain CO₂ cost and gas price scenarios that would lead the Company to
20 re-evaluate strategic asset planning for certain units. Re-evaluation of strategic
21 asset planning would be vetted via the Company's depreciable life studies that are
22 completed every five years, with the next due in 2013.

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

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

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

7 A. Yes. As further discussed in Exhibit No. 29, emission reduction projects of the
8 number and size described above take many years to engineer, plan, and build.
9 When considering a fleet the size of the Company's, there is a practical limitation
10 on available construction resources and labor. There is also a limit on the number
11 of units that may be taken out of service at any given time, as well as the level of
12 construction activities that can be supported by the local infrastructures at and
13 around these facilities. Additional cost and construction timing limitations include
14 the loss of large generating resources during some parts of construction and the
15 associated impact on the reliability of the Company's electrical system during
16 these extended outages. In other words, it is not practical, and it is unduly
17 expensive, to expect to build these emission reduction projects all at once or even
18 in a compressed time period.

19 **Q. Does the Company believe that the pollution control investments**
20 **contemplated in this case meet the "used and useful" standard?**

21 A. Yes. Each of these investments achieves its original intent, provides benefit to
22 customers, and allows the Company to maintain compliance with state issued
23 permits, state implementation plans, and regional SO₂ milestones and backstop

1 trading programs.

2 **Customer Considerations**

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

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

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

1 **Description of Pollution Control Investment Projects**

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

4 A. The scrubber addition project at the Naughton Unit 2 power plant includes the
5 installation of SO₂ controls. The capital investment for the project being placed in
6 service during the test period is approximately \$152 million. Construction began
7 in 2010, and the project is expected to be placed in service by November 2011.
8 The new pollution control equipment will be tied into the existing unit during a
9 scheduled plant maintenance outage. The project will install a flue gas
10 desulfurization (“FGD”) system. The FGD system injects reagent slurry
11 containing sodium carbonate and sodium bicarbonate in the top of an absorber
12 vessel (“scrubber”) with a network of spray nozzles. The distribution of spray
13 nozzles and trays causes the sodium carbonate slurry to intermix with the flue gas
14 passing through the absorber vessel. The SO₂ in the flue gas reacts with the
15 sodium carbonate in the slurry to form waste slurry of sodium sulfite and sodium
16 sulfate. The liquid waste slurry is then captured and transported to a scrubber
17 waste pond for disposal. The scrubber waste will ultimately be dewatered and
18 retained in a closed and capped scrubber waste cell on the Naughton plant site.

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

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

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

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

9 A. No. The Naughton Unit 1 scrubber project is expected to be placed in service
10 during the next planned major maintenance outage for that unit, expected to be
11 complete by May 2012. The planned major maintenance outages for the
12 Company's generation assets are scheduled on a control area basis, considering
13 optimal frequency between overhauls and to minimize the number of major units
14 off line at any one time. The Company completed its most recent overhaul to
15 Naughton Unit 1 in 2008 and is scheduled for its next overhaul in the spring of
16 2012. The Company's intent in establishing the tie-in schedules for the Naughton
17 Unit 1 and Naughton Unit 2 pollution control equipment was to balance the
18 aggregated construction costs and schedules for the pollution control equipment
19 projects against the established planned maintenance overhaul schedules, work
20 plans, and budgets for the respective units.

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

23 A. Yes. The cost of all common facilities that are required to be placed in service to

1 allow prudent operation of either unit's new emission control equipment are
2 incorporated into the Naughton Unit 2 capital investment being placed in service
3 by November 2011. Common facilities include reagent preparation, waste
4 disposal, electrical supply, and ancillary utility systems, as well as site preparation
5 and the chimney.

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

8 A. A stand-alone bag house was installed at the Wyodak power plant for control of
9 PM, SO₂, and Hg emissions consistent with requirements. In order to increase the
10 SO₂ removal efficiency of the unit above 90 percent as required to comply with
11 environmental requirements, a bag house must be utilized in conjunction with the
12 existing dry spray dryer absorbers ("SDAs"). Without a bag house, the best SO₂
13 removal efficiency a SDA on the unit can achieve with Wyodak coal is between
14 70 and 80 percent. Adding the bag house is necessary to achieve the permitted
15 SO₂ removal requirements.

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

21 The bag house captures PM from the flue gas stream as it passes through
22 the bag house and will improve the unit's efficiency in removing SO₂ and Hg
23 from the flue gas. The dry particulate waste stream containing both fly ash and

1 scrubber waste will then be transported to an ash collection pond on adjacent coal
2 mine property for disposal.

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

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

9 A. The scrubber project at the Huntington Unit 1 power plant provides required SO₂
10 controls for the unit, as well as a new scrubber waste material handling system
11 and conversion of the chimney to wet operation. The new waste handling
12 equipment will be designed to manage the increase in waste product from the
13 higher removal efficiency and increased throughput of the scrubber.

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

23 The scrubber waste material handling project includes forced oxidation

1 compressors to allow the full conversion of calcium sulfite to calcium sulfate,
2 larger absorber agitators, hydroclones as a replacement for the existing thickener,
3 vacuum drum filters with associated transfer tanks and pumps, electrical
4 infrastructure, controls, and other miscellaneous appurtenances and support
5 systems. Installation of this equipment will allow the scrubber slurry waste stream
6 to be more effectively dewatered to maintain compliance with scrubber waste
7 landfill disposal requirements. Installation of this new equipment also addresses
8 equipment end-of-life issues for existing equipment including the absorber
9 agitators and the thickener. These particular equipment items were nearing their
10 end-of-life stage and would have required capital replacement in the near future.

11 **Q. Please describe the Hunter Unit 2 power plant bag house conversion project,**
12 **scrubber project, and associated equipment.**

13 A. The bag house conversion project at the Hunter Unit 2 power plant will convert an
14 existing electrostatic precipitator to a bag house to meet PM and Hg emissions
15 control requirements. The bag house will capture PM and help remove Hg from
16 the flue gas stream as it passes through the bag house. The dry particulate waste
17 stream is then transported to an on-site landfill for disposal. Other equipment to
18 be installed as part of the project includes upgrading the scrubber booster fans,
19 boiler reinforcement, new ductwork, modifications to the existing chimney to
20 accommodate wet operation, relocation of the stack opacity monitors, waste
21 material handling systems, electrical infrastructure, controls, and other
22 miscellaneous appurtenances and support systems. The Company's share of the
23 capital investment for the bag house conversion project being placed in service

1 during the test period is approximately \$54 million. Construction began in 2010,
2 and the project was placed in service at the end of April 2011. The bag house
3 conversion was completed during a scheduled plant maintenance outage.

4 The scrubber project at the Hunter Unit 2 power plant will result in
5 improved SO₂ controls for the unit and will install a new scrubber reagent
6 preparation system and an improved scrubber waste material handling system to
7 meet environmental requirements. The scrubber project will increase unit's
8 existing FGD slurry delivery system capacity by replacing recycle pumps and
9 reagent supply piping and appurtenances, effectively increasing the liquid
10 ("slurry") to flue gas ratio within the absorber vessels ("scrubbers"); installing a
11 new higher capacity scrubber reagent preparation system, and expanding waste
12 material handling system capacity with a new system. The FGD system injects
13 lime slurry in the top of a scrubber with a network of spray nozzles and trays. The
14 distribution of spray nozzles and trays causes the lime slurry to intermix with the
15 flue gas passing through the absorber vessel. The SO₂ in the flue gas reacts with
16 the calcium in the slurry to form a slurry waste of calcium sulfite and calcium
17 sulfate. The waste material handling portion of the project will add oxidation air
18 blowers to the system to ensure conversion of the calcium sulfite to calcium
19 sulfate. Calcium sulfate is easier to dewater and the change will allow the slurry
20 waste stream to be more effectively dewatered, and transported to a scrubber
21 waste landfill for disposal.

22 The Company's share of the capital investment for the scrubber FGD
23 system and scrubber waste material handling portions of the project being placed

1 in service during the test period is approximately \$23 million. Construction began
2 in 2010, and the scrubber FGD system project activities were completed and
3 placed in service at the end of April 2011. The scrubber waste material handling
4 portion of the project is expected to be completed by July 2011. The scrubber
5 reagent preparation system portion of the project is expected to be placed in
6 service by March 2012. Costs for the scrubber reagent preparation system portion
7 of the project are not included in this case. The scrubber FGD system scope of
8 work was completed during a scheduled plant maintenance outage. Installation of
9 the reagent preparation system upgrade and the waste handling portion of the
10 project will be completed later, and will not require an extended plant
11 maintenance outage for tie-in.

12 Equipment to be installed as part of the various portions of the scrubber
13 project includes lime slurry reagent preparation equipment; waste material
14 handling system equipment including hydroclones, as a replacement for the
15 existing thickener, and vacuum drum filters; electrical infrastructure; controls; and
16 other miscellaneous appurtenances and support systems.

17 **Q. Is the Company also completing a scrubber project at the Hunter Unit 1**
18 **power plant?**

19 A. Yes. The Hunter Unit 1 scrubber project is being constructed concurrently with
20 the Hunter Unit 2 scrubber project, but on a different schedule. The project is
21 being constructed concurrently with the Hunter Unit 2 project to benefit from
22 installation and operational costs synergies achieved through the use of common
23 facilities between the two units.

1 **Q. Please describe the Hunter Unit 1 power plant scrubber project and**
2 **associated equipment.**

3 A. The scrubber project at the Hunter Unit 1 power plant will result in improved SO₂
4 controls for the unit and will install a new scrubber reagent preparation system
5 and an improved scrubber waste material handling system to meet environmental
6 requirements. The detailed description of the Hunter Unit 1 scrubber project is for
7 the most part identical to that provided for Hunter Unit 2 above.

8 Costs associated with the capital investment for the Hunter Unit 1
9 scrubber project ARE NOT included in the revenue requirement in this case due
10 to the projected in-service dates of the respective portions of the project.
11 Construction began in 2011, and the scrubber FGD system portion of the project
12 is expected to be fully placed in service by May 2014 following a scheduled plant
13 maintenance outage on the unit. The scrubber reagent preparation portion of the
14 project is scheduled to be placed in service by March 2012. The scrubber waste
15 material handling portion of the project is expected to be placed in service by
16 March 2013. Installation of the reagent preparation and waste handling portions of
17 the project will be completed while the plant is in service, and will not require an
18 extended plant maintenance outage for tie-in.

19 **Q. Please describe the Jim Bridger Unit 3 power plant scrubber project and**
20 **associated equipment.**

21 A. The scrubber project at the Jim Bridger Unit 3 power plant will result in improved
22 SO₂ controls for the unit by allowing the scrubber bypass dampers to bypass less
23 flue gas. The scrubber project will increase the unit's existing FGD slurry

1 delivery system capacity by replacing recycle pumps and reagent supply piping
2 and appurtenances, effectively increasing the liquid (“slurry”) to flue gas ratio
3 within the absorber vessels (“scrubbers”); install new scrubber vessel internals
4 (“trays, piping and nozzles”); replace induced draft fans; install variable
5 frequency drives; and install the associated power distribution, controls and
6 appurtenances. The FGD system injects sodium-based slurry in the top of a
7 scrubber with a network of spray nozzles and trays. The distribution of spray
8 nozzles and trays causes the slurry to intermix with the flue gas passing through
9 the absorber vessel. The SO₂ in the flue gas reacts with the sodium in the slurry to
10 form a slurry waste of sodium sulfite and sodium sulfate. The scrubber waste, in
11 slurry form, is sent to a waste pond where the waste liquor is allowed to evaporate
12 and the solids are ultimately impounded in the landfill.

13 The Company’s share of the capital investment for the scrubber project
14 being placed in service during the test period is approximately \$17 million.
15 Construction began in 2010, and the scrubber project activities are expected to be
16 completed in June 2011. The scrubber waste material handling portion of the
17 project is expected to be completed by July 2011. The scrubber project scope of
18 work is being completed during a scheduled plant maintenance outage.

19 **Q. Please describe the other major pollution control projects and associated**
20 **equipment contemplated in this case.**

21 A. The other major pollution control projects to be placed in service during the test
22 period include:

23 (1) the Naughton Unit 2 low NO_x burners installation project;

1 (2) the Wyodak low NO_x burners installation project; and

2 (3) the Hunter Unit 2 low NO_x burners installation project.

3 The low NO_x burners projects referenced above will install new burners that
4 utilize improved combustion characteristics and a separated over-fire air supply to
5 the boiler to reduce NO_x emissions.

6 **Q. Please describe the emissions improvements that will be achieved with the**
7 **pollution control projects described above.**

8 A. The pollution control equipment investments described above are required by the
9 permit terms and conditions issued in response to the environmental requirements
10 described herein and support the Company's ongoing commitment to reduce SO₂
11 emissions from the Company's generation fleet by approximately 50 percent
12 compared to 2005 levels. In addition to reducing SO₂ emissions, the projects
13 support the Company's ongoing commitment to reduce NO_x emissions from the
14 Company's generation fleet by approximately 40 percent compared to 2005
15 levels. The Company believes that these investments are complementary to and
16 consistent with BART Regional Haze planning requirements intended to improve
17 the visibility in certain national parks and wilderness areas, and that they
18 exemplify a reasonable approach to achieving emission reductions in our
19 operating territory. The emission reductions that result from these projects have
20 been incorporated into the approved operating permits for the respective units.

21 **Q. Have the costs of the projects been prudently managed by the Company?**

22 A. Yes. The scrubber and bag house projects described above have been contracted
23 under lump-sum, turnkey, engineer, procure and construct ("EPC") contract terms

1 which resulted from competitive bidding processes. The burner replacement
2 projects have been contracted under multiple lump-sum contracts which resulted
3 from competitive bidding processes or job-specific work releases under
4 established service level agreement rate structures. PacifiCorp management
5 continues to provide oversight of the projects and closely manages any project
6 execution plan changes or potential contract scope changes. PacifiCorp believes
7 that the permitted and constructed pollution control projects and their timing
8 appropriately balance the need for emission reductions over time with the costs
9 and other concerns of our customers, our state utility regulatory commissions, and
10 other stakeholders.

11 **Q. Are there additional operating costs that will be incurred as a result of the**
12 **installation of pollution control equipment?**

13 A. Yes. Unfortunately, but unavoidably, the operation of the new pollution control
14 equipment results in increased operation and maintenance costs associated with
15 reagent, waste disposal, and equipment maintenance. Incremental operation and
16 maintenance costs associated with the Dave Johnston Unit 3 scrubber and
17 baghouse project placed in service in May 2010, the Wyodak pollution control
18 project placed in service in April 2011, and the Naughton Unit 2 scrubber project
19 to be placed in service in November 2011 are included in this case. These costs,
20 as well as the capital investments identified above, are included in the revenue
21 requirement calculations for this case as explained in Mr. Steven R. McDougal's
22 direct testimony.

1 **Description of Generation Plant Turbine Upgrade Investment**

2 **Q. Please describe the Hunter Unit 2 power plant turbine upgrade project**
3 **presented in this case.**

4 A. The Hunter Unit 2 power plant high pressure (“HP”), intermediate pressure
5 (“IP”), and low pressure (“LP”) turbine sections were replaced as part of this
6 project. The project was placed in service in April 2011.

7 **Q. Please describe the efficiency improvements that will be achieved with the**
8 **turbine upgrade project described above.**

9 A. The Company expects the Hunter Unit 2 turbine upgrade to allow more efficient
10 turbine performance without increasing emissions, such that approximately 9
11 megawatts (Company share, adjusted for pollution control equipment auxiliary
12 load) of incremental capacity can be generated by the unit. Mr. Gregory N. Duvall
13 has included incremental capacity upgrade in the net power cost analysis
14 associated with these projects in his direct testimony.

15 **Q. What is the basis for justification of this investment?**

16 A. As part of the Company’s efforts to meet the growing demand for generation, and
17 given the advancing technological improvements in steam turbine design and
18 manufacturing, the Company has initiated a turbine upgrade initiative. This
19 turbine upgrade initiative will further enhance PacifiCorp’s overall generation
20 capability and cycle efficiency for the large thermal units being provided with this
21 equipment.

1 **Description of Other Generation Plant Investments**

2 **Q. What other generation plant capital investments are included in this**
3 **application?**

4 A. Generation plant repair and replacement investments and a coal unloading facility
5 addition at the Hayden power plant are the remaining projects included in this
6 case. The repair and replacement projects fall primarily within three major
7 categories: (i) boiler section replacements; (ii) control system upgrades; and (iii)
8 other. The revenue requirement impact of these investments has been included in
9 Mr. McDougal's direct testimony.

10 **Q. How will customers benefit from the repair and replacement capital**
11 **expenditures contemplated in this case?**

12 A. These capital expenditures enable the Company to maintain safe, reliable, and
13 cost-effective operation of an aging generation fleet. The Company's plants
14 produce energy at costs lower than market prices, enabling the Company to serve
15 its customers at some of the lowest retail electricity prices in the United States.
16 Prudent investment in the Company's existing generating units increases the
17 probability of continued safe and reliable operation of these low-cost resources.

18 **Q. Please describe the Wyodak air cooled condenser replacement project.**

19 A. The Wyodak air cooled condenser ("ACC") has been in service for 33 years and
20 has reached its end of useful life. This replacement project replaces all of the
21 ACC's tube bundles and headers, both of which are experiencing failures. Failed
22 tubes and welds are allowing air in-leakage to the ACC which increases turbine
23 backpressure, allows for accelerated corrosion of the carbon steel tubes and

1 headers in the ACC, and results in freeze/thaw damage during cold weather
2 operation. The new project was placed in service in May 2011. The PacifiCorp
3 share of the capital investment for the scrubber project being placed in service
4 during the test period is approximately \$22 million.

5 **Q. How will customers benefit from the Wyodak air cooled condenser**
6 **replacement project?**

7 A. The Wyodak air cooled condenser replacement project is expected to result in
8 improved unit reliability and efficiency. From a unit reliability perspective,
9 continued operation of the ACC in its current condition has a high potential of
10 causing progressively more unit outages and/or derates. From a unit efficiency
11 perspective, during the winter months it is typical for the Wyodak plant to
12 increase turbine back pressure to ensure that the ACC does not freeze. During the
13 summer months, poor ACC performance also causes the plant to run with high
14 turbine back pressure. Increasing unit back pressure leads to increased fuel
15 consumption for a given megawatt output. By proceeding with the ACC
16 replacement project, customers will benefit from improvements in the areas
17 discussed above as well as advancements in currently available ACC technology.
18 Technology improvements have resulted in increased equipment efficiency
19 without increasing the size of the ACC structure. This efficiency improvement
20 comes without increasing the power consumption of the existing cooling fans.

21 **Q. Please describe the Hayden power plant coal unloading facility project.**

22 A. Currently, the Hayden plant can only receive coal which is shipped by truck. The
23 new coal unloading facility will allow the Hayden plant to also receive coal that is

1 shipped by rail. The project includes construction of a new rail spur and loop,
2 bridges, unloading hopper, belts, transfer points, feeders, crushers and other
3 equipment. The project is expected to be ready for service in October 2011, at a
4 total loaded cost of approximately \$12 million (Company's share).

5 **Q. How will customers benefit from the Hayden power plant coal unloading**
6 **capital expenditure?**

7 A. Hayden Units 1 and 2 currently consume coal produced at Peabody Energy's
8 Twentymile mine. This coal is transported to the plant by truck over county roads.
9 The current contract with Peabody to supply coal for Hayden expires at the end of
10 2011. In order to ensure a reliable, long-term supply of low-cost fuel to the plant
11 after expiration of the Peabody contract, Hayden's owners (Public Service
12 Company of Colorado, Salt River Project Agricultural Improvement and Power
13 District, and PacifiCorp) requested bids from a number of regional mines that
14 have capability to supply suitable coal to Hayden. Many of these regional mines
15 are located too far from the Hayden plant to economically deliver coal to the
16 facility by truck. Construction of the rail unloading facility allows these suppliers
17 to ship coal to the plant at economic rates and to compete effectively with nearby
18 suppliers. Ratepayers will benefit from the increased competition to supply cost-
19 effective fuel to the plant.

20 **Description of Hydro Investments**

21 **Q. What hydro plant capital investments are included in this application?**

22 A. The hydro plant regulatory and new infrastructure investments contemplated in
23 this case are primarily associated with new license implementation measures for

1 the North Umpqua Hydroelectric Project; Federal Energy Regulatory Commission
2 No. 1927; and dam remediation work at the Ashton Hydroelectric Project; Federal
3 Energy Regulatory Commission No. 2381. The revenue requirement impact of
4 these investments has been included in Mr. McDougal's direct testimony.

5 **Q. Please describe the Lemolo Unit 2 reroute project.**

6 A. The Company's investment in the Lemolo Unit 2 reroute project is driven by
7 Settlement Agreement Section 6.1 of the referenced FERC license. These new
8 reach pipe facilities will collect the outflow from the Lemolo 2 plant and transport
9 the water to Toketee Lake. The purpose of the project is to prevent significant
10 increases and decreases in the flow levels in the Umpqua River downstream of the
11 plant which could have detrimental impacts on the native fishery. The project is
12 planned to be placed into service in December 2011 and is expected to cost
13 approximately \$9 million.

14 **Q. Please describe the Slide Creek tailrace barrier project.**

15 A. The Company's investment in the Slide Creek tailrace barrier project is driven by
16 Settlement Agreement Section 4.1.1(f) of the referenced FERC license. These
17 new facilities will reduce water turbulence and prevent access to the Slide Creek
18 plant in order to prevent delay or injury to anadromous fish during their migration
19 up the North Umpqua River. The project is planned to be placed into service in
20 December 2011 and is expected to cost approximately \$9 million.

21 **Q. Please describe the Ashton Dam seepage control project.**

22 A. The Company's investment in the Ashton Dam seepage control project was
23 driven by the need to remediate the dam embankment with a state of the art

1 engineered fill. The project being considered by this proceeding consists of the
2 low level flow bypass tunnel installation, which will allow for the removal and
3 reconstruction of the dam embankment. It is a non-elective, regulatory and
4 mandated project under the jurisdiction of the Federal Energy Regulatory
5 Commission and a Board of Consultants. The bypass tunnel was placed into
6 service in March 2011 at a cost of approximately \$8 million.

7 **Q. What is the basis for justification of these investments?**

8 A. The Soda Springs hydroelectric project with a nameplate rating of 11 megawatts
9 and the Lemolo 2 hydroelectric project with a nameplate rating of 33 megawatts
10 are part of the eight project development comprising the North Umpqua
11 Hydroelectric Project. The economic evaluation for the entire development was
12 conducted in association with the FERC re-licensing process prior to the issuance
13 of the current 2003 license. The analysis indicated that the 35-year license would
14 provide energy for customers at rates substantially lower than market prices. The
15 Ashton Dam seepage control project was determined to be the least cost dam
16 remediation or dam removal alternative that would meet the approval of the
17 FERC and the project Board of Consultants.

18 **Customer Benefits**

19 **Q. How will customers benefit from these capital expenditures?**

20 A. The capital expenditures described above and otherwise included in this case
21 enable the Company to maintain safe, reliable, and cost-effective operation of an
22 aging generation fleet. The Company's plants produce energy at costs lower than
23 market prices, enabling the Company to serve its customers at some of the lowest

1 retail electricity prices in the United States. Prudent investment in the Company's
2 existing generating units increases the probability of continued safe and reliable
3 operation of these low-cost resources.

4 **Description of Incremental O&M Costs**

5 **Q. Are there incremental O&M costs contemplated in this case associated with**
6 **recently completed wind projects?**

7 A. Yes. Incremental O&M costs for the Company's recently completed Dunlap I
8 wind project are included in this case. The Dunlap I wind project achieved
9 commercial operation on October 1, 2010. The incremental O&M costs included
10 in this case are known and measurable costs associated with ongoing operation of
11 the facilities, including labor, contracts, parts, and consumables. These costs are
12 summarized in Mr. McDougal's direct testimony.

13 **Q. Are there incremental O&M costs contemplated in this case associated with**
14 **operation of the Cholla Unit 4 power plant?**

15 A. Yes. The mine which historically supplied cost-effective coal to Cholla Unit 4
16 was completely mined out in 2010. While also cost-effective, the new fuel being
17 supplied to the facility contains more sulfur and ash. In order to continue to
18 comply with environmental requirements while burning the new fuel, a new
19 scrubber and bag house were installed on the unit in 2008. The new high-
20 removal-rate scrubber and the higher sulfur coal have combined to raise limestone
21 consumption significantly. Also, the new fuel has raised costs for pulverizer and
22 boiler maintenance in the plant. Even with these changes, Cholla Unit 4 continues
23 to provide essential energy and system regulation benefits to PacifiCorp's electric

1 system at an attractive price. Incremental operation and maintenance costs of
2 approximately \$1.2 million associated with the operational changes described
3 above are included in this case. These costs are summarized in Mr. McDougal's
4 direct testimony.

5 **Conclusion**

6 **Q. Please summarize your testimony.**

7 A. The pollution control equipment investments presented in this case are required to
8 comply with current, proposed, and probable environmental regulations. The
9 investments allow for the continued operation of low-cost coal-fired generation
10 facilities, while achieving significant environmental improvements.

11 The Company is also making other prudent capital expenditures in its
12 existing generation fleet, including hydro resources, which will benefit customers
13 by maintaining safe, reliable, efficient, cost-effective generating resources and
14 production facilities. The capital investments included in this case are reasonable
15 and prudent, and the Company should be granted full cost recovery for these
16 investments.

17 The Company continues to prudently manage O&M costs. The Company
18 should be granted full recovery of the incremental O&M costs presented in this
19 case.

20 **Q. Does this conclude your direct testimony?**

21 A. Yes.