Rocky Mountain Power
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Chad A. Teply

Generation Capital Additions

January 2014

Q. Please state your name, business address and present 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 84116. 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 have 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 support the prudence of capital investments in the new Lake Side 2 combined cycle combustion turbine ("CCCT") natural gas fueled resource, certain pollution control equipment retrofits on existing coal fueled resources, and other significant generation plant projects being placed in service during the test period in this docket, July 1, 2014 through June 30, 2015 ("Test Period").

Background

Q. Please provide a general description of the Lake Side 2 CCCT project being placed in service during the Test Period and the benefits gained from the investment.

A. The Lake Side 2 Significant Energy Resource Decision was approved by the Public Service Commission of Utah ("Commission") in Docket No. 10-035-126 on April 20, 2011, following a comprehensive review of the project need and the Company's 2008 Request for Proposals ("RFP") by the Commission, the Division of Public Utilities, the Office of Consumer Services and other interested parties. The Lake Side 2 project was determined to be the lowest reasonable cost option to meet additional electricity needs of customers, taking into account costs and risks. The Commission Order in Docket No. 10-035-126 contemplates a June 2014 in-service date at a projected cost of [redacted], including transmission, to acquire, construct and integrate the project into PacifiCorp's system. Rather than repeating what is already on record in Docket No. 10-035-126, I recommend that the Commission take administrative notice of that docket for additional evidence supporting the acquisition of the Lake Side 2 project.

The Lake Side 2 project remains on schedule to be placed in service by June 2014 and is currently projected to be completed with a capital cost of approximately [redacted], excluding transmission; approximately [redacted] when including the Lake Side 2 transmission service project also included in this docket. In each case, the project costs are trending favorably for customers to the Company's previous forecasts and economic assessments originally utilized to support the investment decision.

Q. Please provide a general description of the emissions control equipment investments being placed in service during the Test Period and the benefits gained from the investments.

A. The emissions control equipment investments included in this case are required to comply with environmental laws, including the Clean Air Act Regional Haze Rules and the Mercury and Air Toxics Standards ("MATS"), being administered by the respective state agencies in which the units reside, as well as the U.S. Environmental Protection Agency ("EPA"). The emissions control investments primarily result in the reduction of nitrogen oxides ("NO_X"), particulate matter ("PM"), sulfur dioxide ("SO_2"), and mercury ("Hg") emissions, depending upon the individual installation at the retrofitted facilities.

The investments include a baghouse conversion (approximately [redacted], Company share) and low NO_X burners ("LNB") installation (approximately [redacted], Company share) at Hunter Unit 1, and a selective catalytic reduction ("SCR") system installation (approximately [redacted], Company share) at Hayden Unit 1. The Hunter Unit 1 projects are required to be installed by spring 2014 by the state of Utah Regional Haze State Implementation Plan ("SIP") and have been determined to be the least cost compliance alternative for the unit when incorporating costs for potential greenhouse gas ("GHG") regulatory outcomes, other emerging environmental regulations, and potential long-term incremental emissions reduction strategies into the economic assessments of the projects.

The Hayden Unit 1 SCR is required by the state of Colorado's Regional Haze SIP to be installed by December 31, 2016. The Hayden Unit 1 SCR is also a key component of the NO_X reduction plan required to have been submitted by Public Service Company of Colorado (the operator of Hayden Unit 1) to the Colorado Public Utilities Commission under the Colorado Clean Air Clean Jobs Act. The Colorado Public Utilities Commission ultimately approved Public Service Company of Colorado's NO_X reduction plan, including the Hayden Unit 1 SCR project, on December 9, 2010. Public Service Company of Colorado has since received a Certificate of Public Convenience and Necessity ("CPCN") for the SCR project from the Colorado Public Utilities Commission after having demonstrated that the investment was in the best interests of customers. PacifiCorp is a minority owner of Hayden Unit 1, with an interest of 24.5 percent. The Participation Agreement governing that ownership interest mandates the installation of capital improvements that are required by applicable law. The Participation Agreement also places an independent obligation on Public Service Company of Colorado, as Operating Agent, to operate Hayden Unit 2 in accordance with applicable law. The applicable laws requiring the Hayden Unit 1 SCR investment are mentioned above and discussed in detail later in this testimony.

In each case, installation of these major emissions control retrofit projects have been aligned with scheduled major maintenance outages for the affected units to mitigate replacement power cost impacts while benefiting from overlapping major maintenance outage time frames. These environmental compliance investments constitute approximately [redacted] (approximately [redacted]) of the total capital investments projected to be placed in service within the Test Period. These environmental compliance investments will allow the retrofitted facilities to continue to operate as low-cost generation resources for the benefit of customers.

Q. Please provide a general description of the other significant generation plant projects being placed in service during the test period and the benefits gained from the investments.

A. The other significant generation plant projects being placed in service during the test period include the Blundell geothermal resource well integration project and the Naughton Unit 3 natural gas conversion project.

The Blundell geothermal resource well integration project integrates two new geothermal resource wells into the Blundell generation system. One production well and one injection well, along with associated appurtenances, have been drilled and will be placed in service to support continued reliable electricity production at the site.

The Naughton Unit 3 natural gas conversion project is being pursued as the least cost compliance alternative to the state of Wyoming Regional Haze SIP requirements for Naughton Unit 3. The natural gas conversion project was identified as the least cost alternative to installing an SCR and baghouse on Naughton Unit 3 via a CPCN docket in Wyoming. The Company is currently awaiting EPA approval of the natural gas conversion project as part of EPA's review and final action on the state of Wyoming Regional Haze SIP. EPA's final action in this regard is currently expected by January 10, 2014.

These investments constitute approximately [redacted] (approximately [redacted]) of the total capital investments projected to be placed in service within the test period for this docket.

Lake Side 2 Generation Resource Addition

<u>Lake Side 2 Project Overview</u>

Q. Please describe the Lake Side 2 project.

A. Lake Side 2 is located on a 63.6 acre site in Vineyard, Utah. It is a 645 MW natural gas-fired electric generation facility, consisting of a 2x1 combined-cycle configuration, using two combustion turbine generators and a single steam turbine generator. More specifically, Lake Side 2 is nominally rated at 548 MW base load and 97 MW of duct firing for a total net capacity of 645 MW at the average ambient temperate of 52 degrees Fahrenheit. Each combustion turbine exhausts into its own heat recovery steam generator which then commonly supply a single steam turbine generator. The electrical energy generated by Lake Side 2 will be delivered to a new 345 kV point of interconnection substation (Steel Mill) where it will tie into the PacifiCorp transmission system. Lake Side 2 is currently scheduled to reach substantial completion to generate and provide energy and capacity to customers by June 2014.

Q. Please describe the characteristics of Lake Side 2.

A. Lake Side 2 is located in the Company's east balancing authority. The Company can dispatch power and energy from Lake Side 2 on a forward, day-ahead basis, with real-time optimization of the plant's usage. This dispatch flexibility will give the Company an additional system resource with the ability to provide operating reserves, load-following reserves, and automatic generation control. The added system flexibility will provide increasing benefit to PacifiCorp as (1) load grows, (2) PacifiCorp's existing flexible contracts expire, and (3) new wind and solar resources are added to the system.

<u>Total Currently Projected Cost of Lake Side 2</u>

Q. What was the total projected cost of Lake Side 2 as evaluated in the Company's 2008 RFP?

A. The total projected cost of Lake Side 2 as evaluated in the 2008 RFP was [redacted].

Q. Please describe the components of the total projected cost associated with the development and engineering, procurement, and construction of Lake Side 2 as evaluated in the 2008 RFP.

A. The total estimated capital investment of [redacted] included the following estimated costs:

- A transfer to in-service cost of [redacted] for the generation asset including:
    - [redacted] for engineering, procurement, and construction
    - [redacted] for sales tax
    - [redacted] for owner's cost

- [redacted] for allowance for funds used during construction ("AFUDC")
- [redacted] for property taxes during construction

- [redacted][1] for transmission upgrade costs required to integrate the plant into the Company's east balancing authority.

Q. Have there been any changes in the Lake Side 2 generation asset cost forecast to be placed in service in 2014?

A. Yes, the Company has reduced its forecast of the generation asset's costs to be placed in service in 2014 by approximately [redacted]. This reduction is primarily due to a restructuring of the water purchases required for the project from the Central Utah Water Conservancy District ("CUWCD"). Instead of purchasing all of the water needed to meet the long-term requirements of Lake Side 2 during the construction period, the water purchases from the CUWCD have been phased in to align with expected generation and cooling water needs of Lake Side 2. This phasing in of water purchases is currently estimated to reduce revenue requirement on a present value basis by approximately [redacted] due to deferred capital payments and avoided fixed "take or pay" O&M costs for water under the CUWCD water supply agreement. Future water purchases, amounting to approximately [redacted], will be phased in over the 2015 to 2019 time period.

In addition to changes in the timing of water purchases, the Company's current Lake Side 2 generation asset cost forecast reflects reductions of

[1] PacifiCorp Transmission estimated the integration costs for each delivery point in Attachment 13 of the 2008 RFP. An initial estimate of [redacted] was updated on July 29, 2010, to [redacted] in 2010 dollars escalated at 1.89 percent annually through 2014 for a nominal cost of [redacted]. These two estimates are available at http://www.oasis.pacificorp.com/oasis/ppw/main.htmlx. The [redacted] estimate was used in the Final Shortlist evaluation process.

approximately [redacted] associated with changes in sales tax, owner's costs, AFUDC, property taxes, and other internal costs. The combination of these updates results in a reduction of the total capital investment forecast for Lake Side 2 from [redacted] to approximately [redacted].

Q. Have there been any changes to the estimated transmission upgrade costs to integrate the plant into the Company's east balancing authority from the [redacted] used in the final shortlist evaluation process?

A. Yes. The Company's forecast for the transmission upgrade costs is currently estimated to be approximately [redacted].

Q. What is the updated total forecasted capital investment for Lake Side 2?

A. The combination of the updated forecast of generation asset to be placed in service in 2014, the updated transmission upgrade costs to be placed in service 2014, and deferred water purchases results in reducing the total forecasted capital investment for Lake Side 2 from [redacted] to approximately [redacted].

Contract Terms and Conditions

Q. Please describe key engineering, procurement, and construction ("EPC") contract terms and conditions related to contractor performance risk.

A. If the EPC contractor does not achieve substantial completion of Lake Side 2 by June 1, 2014, the EPC contract for the project provides for delay liquidated damages. Any delay in achieving substantial completion that is greater than [redacted] following June 1, 2014, will entitle the Company to terminate the Agreement and to seek additional appropriate remedies. The EPC contractor's performance is secured by a parent guarantee and retainage or a retainage letter of credit equal to [redacted] percent of all payments made (other than the final payment).

The warranty under the EPC contract is effective for [redacted] beginning June 1, 2014; provided that any repairs (other than the power generation equipment) made during the warranty period will be warranted for a period that is the greater of one year or the balance of the warranty period. The EPC contractor has agreed to obtain insurance and assume risk of loss at the customary levels requested by the Company. The EPC contractor will not be liable for consequential damages; but, with a few exceptions, will be liable for losses under the EPC contract up to the aggregate amount of 100 percent of the contract price.

In addition, the Company has secured an additional warranty on the power generation equipment (the combustion turbines, steam turbine and associated generators) for the earlier of the [redacted] of the substantial completion date, [redacted] equivalent operating hours, or [redacted] months following delivery of the equipment.

<u>Lake Side 2 Project Implementation</u>

Q. What is the current status of Lake Side 2 project construction?

A. Construction of Lake Side 2 plant facilities and installation of plant equipment is complete. Piping, electrical, instrumentation and control systems installation work is approximately 85 percent complete. Commissioning of major equipment and systems has begun and will continue through the first quarter of 2014. First fire of Combustion Turbine 21 (the first combustion turbine in the commissioning queue) is expected in January 2014, followed by commissioning of the heat recovery steam generators and finally the steam turbine and all supporting systems. Tuning and testing of the plant is currently scheduled for April and May 2014 to support commercial operation by June 2014.

Pollution Control Investment Projects - Hunter Unit 1

<u>Hunter Unit 1 Projects Overview</u>

Q. Please describe the Hunter facility and Hunter Unit 1 in particular.

A. The Hunter plant is a three-unit coal-fueled power plant with a net generation capacity of approximately 1,320 MW and a currently approved depreciable life for ratemaking purposes of 2042 in Utah. The plant is located approximately 158 miles south of Salt Lake City, Utah near the town of Castle Dale, Utah, and is operated under a base load generation regime. Unit 1 is 93.8 percent owned by the Company and 6.2 percent owned by the Utah Municipal Power Agency, with the Company responsible for operation and maintenance of the unit and the Hunter plant as a whole. The Hunter plant site includes the main power station buildings for Units 1 through 3, water storage reservoirs, coal stock piles, ash disposal, and a small research farm to reclaim wastewater and a portion of storm water.

Units 1 and 2 are basically identical units when considering their base design and originally installed boiler and steam turbine generator equipment. Unit 3 is identical in layout to Units 1 and 2 except the boiler and turbine are from different manufacturers.

Water for plant use is released into the Cottonwood Creek from Joe’s Valley and conveyed by a direct pipeline from the Millsite Reservoir to the plant. Potable water is piped from the cities of Castle Dale, Utah or Clawson, Utah. Hunter is a zero discharge plant. The balance of water is evaporated from a pond or used for irrigation of hay crops on the adjacent research farm. Plant sewage is treated and discharged to the evaporation pond.

Coal is supplied by truck from the nearby Sufco, Cottonwood, Dugout, and Deer Creek mines. Hunter has a blending facility in the fuels preparation facility, which allows for combustion of various coal types.

The Hunter plant currently employs approximately 220 personnel, including approximately 170 union craft personnel represented by the International Brotherhood of Electrical Workers Local 57.

Q. Please describe the Hunter Unit 1 baghouse conversion project and associated equipment.

A. The Hunter Unit 1 baghouse conversion project replaces the originally installed particulate matter ("PM") control equipment (electrostatic precipitator) on the unit with a best available retrofit technology baghouse to meet the Company's emissions compliance obligations required by the Regional Haze Rules and incorporated into the state of Utah's Regional Haze SIP and associated permits by spring 2014. The baghouse will capture PM and mercury from the flue gas stream as it passes through the equipment. Capturing mercury in the baghouse allows the unit to comply with the EPA's MATS requirements for mercury capture by the prescribed deadline of April 16, 2015, without installing incremental stand-alone mercury emissions control equipment. The dry particulate waste stream captured in the baghouse is transported to an on-site landfill for disposal.

An additional emissions control benefit that the baghouse brings to Unit 1 is the ability to close the scrubber bypass currently installed on the unit, which when considered in conjunction with the Hunter Unit 1 scrubber, reagent preparation, and waste handling projects completed on the unit in 2012 allows the unit to meet a reduced SO_2 emissions limit required by the state of Utah Regional Haze SIP and associated permits by spring 2014.

Other equipment to be installed as part of the baghouse project includes upgraded booster fans, boiler reinforcement, new ductwork, modifications to the existing chimney, relocation of the stack opacity monitors, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

The Company's share of the capital investment for the baghouse conversion project included in this case is approximately [redacted]. Construction of the project began in 2013, and the baghouse conversion is scheduled to be completed and placed in service following a planned major maintenance outage on the unit in spring 2014. The project cost is trending favorably to the cost initially assessed during the economic analysis and authorization for expenditure stage of the project.

Q. Please describe the Hunter Unit 1 LNB installation project.

A. The LNB installation project on Hunter Unit 1 includes the installation of NO_X combustion controls that replace originally installed equipment. The new burners utilize improved combustion characteristics and a separated over-fire air supply to the boiler to reduce NO_X emissions.

The Company's share of the capital investment for the project is approximately [redacted]. The project is scheduled to be completed and placed in service following the same spring 2014 planned major maintenance outage on the unit referenced above. The project cost is trending favorably to the cost initially assessed during the economic analysis and authorization for expenditure stage of the project.

Q. Have Hunter Units 2 and 3 been equipped with LNB and baghouse retrofit technologies that provide emissions reductions consistent with those being installed on Hunter Unit 1?

A. Yes. Pursuant to Utah Regional Haze SIP requirements, Unit 2 was equipped in 2011 with the same LNB and baghouse retrofit technologies contemplated in this docket for Hunter Unit 1. The same post-retrofit emissions limits for NO_X (0.26 pounds per million Btu) and particulate matter ("PM") (0.015 pounds per million Btu) are required for each unit. The Commission reviewed the Unit 2 emissions control equipment investments for ratemaking purposes in a past general rate case docket. The Unit 2 equipment is included in the Company's rate base.

Unit 3 was equipped with a fabric filter baghouse (1983) when the unit was originally constructed and was retrofitted with LNB technology in 2007. The Commission reviewed the Unit 3 LNB investment for ratemaking purposes in a past general rate case docket. The Unit 3 LNB equipment is included in the Company's rate base.

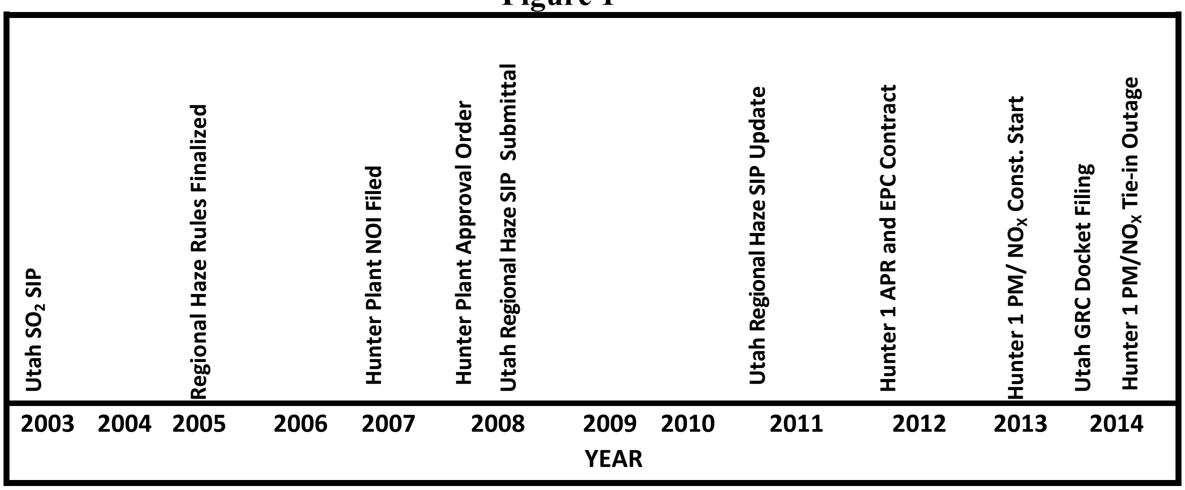
All three Hunter units are equipped with wet lime scrubbers to control sulfur dioxide emissions to a rate of 0.12 pounds per million Btu.

Hunter Unit 1 Projects Drivers and Alternatives Assessments

Q. What are the key permits and/or regulations requiring the Hunter Unit 1 baghouse and LNB projects to be installed?

A. To continue compliant operation of Hunter Unit 1, the Company must install the projects described herein to control emissions of NO_X, PM, and SO_2 criteria pollutants as required by Regional Haze Rules, the state of Utah's §309(g) Implementation Plan, the state of Utah's Best Available Retrofit Technology ("BART") review process, and the state of Utah's Approval Order (DAQE-AN0102370012-08) dated March 2008. Figure 1 below is a general timeline of the significant regulatory actions and regulations that have established the course of events.

Figure 1



The state of Utah Regional Haze SIP and permit requirements for the Hunter Unit 1 projects were finalized in 2008; detailed economic assessment of compliance alternatives and competitive procurement activities were completed in 2012; construction of the project began in 2013; and the baghouse conversion project is scheduled to be completed and placed in service following a planned major maintenance outage on the unit in spring 2014. Additional background regarding the Regional Haze compliance obligations facing Hunter Unit 1 is provided in Exhibit RMP___(CAT-1).

Q. What are the Company's specific obligations under the Hunter Unit 1 permit conditions?

A. The Utah Regional Haze SIP and associated permit for the projects require that emissions control equipment for the unit be installed and operated in compliance with the following emissions limits.

Pollutant	**Emissions Limit (lb per MMBtu)[b]**
NO_X	0.26 (30-day rolling)
SO_2	0.12 (30-day rolling)
PM/PM_{10} [a]	0.015 (annual testing)
CO	0.34 (30-day rolling)

(a) Filterable portion only
(b) See Permit DAQE-AN102370012-08, Article 10

Q. Did the Company consider alternative technologies to the Hunter Unit 1 control projects included in this case when working with the state of Utah to assess Regional Haze compliance requirements incorporated into the Utah Regional Haze SIP?

A. Yes. The Company completed two technical studies of note to evaluate NO_X, SO_2, and PM control technology alternatives for Hunter Units 1. In October 2002, Sargent and Lundy completed a coal fleet-wide *Multi-Pollutant Control Report* (under attorney work product privilege); and in January 2005, Sargent and Lundy completed the *NO_X Emission Reduction Technologies Study,* and in November

2003, EPSCO International Inc. completed a *Phase III Recommendations* study of the original PM control equipment on the unit. See Exhibit RMP___(CAT-2) for additional discussion regarding study details.

The *Multi-Pollutant Control Report* investigated the cost and necessity of NO_X controls including both boiler in-combustion and post-combustion controls, PM controls including upgraded electrostatic precipitators, polishing baghouses and full-scale fabric filter replacements.

The *NO_X Emission Reduction Technologies Study* compared emission control technologies, status of the technology development, performance, approximate initial capital costs, and approximate fixed and variable operational and maintenance costs.

The *Phase III Recommendations* study of the electrostatic precipitators ("ESP") and was used as the basis for the decision to convert the Hunter Unit 1 ESP to a baghouse. The decision making process began when the same type of conversion was made at Huntington Unit 2 (2004-2006). The ESP at Hunter Unit 1 and Unit 2 and Huntington Unit 1 and Unit 2 are identical, and in 2003 it had become apparent that the Huntington Unit 1 and Unit 2 ESP's were having operational difficulties. EPSCO International, Inc. was retained to study the situation, identify options and make recommendations for the Huntington and Hunter units.

Q. Has the Company updated its review of alternative technologies to the Hunter Unit 1 control projects included in this case to support the state of Utah with its ongoing assessment of Regional Haze compliance requirements in the Utah Regional Haze SIP?

A. Yes. In 2012, the Company contracted with CH2M Hill to complete updated BART analyses for Hunter Units 1, 2 and 3 for criteria pollutants NO_X, PM_{10} and SO_2. In completing these BART analyses, technology alternatives were investigated and potential reductions in emissions were quantified.

Q. Did the Company explore compliance flexibility, if any, with the environmental agencies having jurisdiction (i.e. state of Wyoming and/or EPA)?

A. Yes. As a result of negotiations with the Utah Division of Air Quality, the Company was allowed to delay the installation of the emission control equipment included in this case until the unit's planned major maintenance overhaul in 2014, in lieu of attempting to complete the project during the unit's 2010 planned major maintenance overhaul (which fell within the 2008 to 2013 Regional Haze planning period originally prescribed by the state of Utah). Please refer to Exhibit RMP___(CAT-1) for additional information regarding the Company's efforts to explore compliance timeline flexibility for the Hunter Unit 1 Regional Haze compliance projects.

Q. Has the Company evaluated whether the risk-adjusted, least-cost alternative to comply with environmental requirements was to invest in the emissions control equipment included in this case or to idle Hunter Unit 1?

A. Yes. Prior to executing the EPC contract for the baghouse project in June 2012, the Company evaluated alternatives to comply with environmental requirements other than to complete the project. The Company used its System Optimizer Model to evaluate multiple alternatives. In brief, the major alternatives reviewed are:

(1) Continue to operate and incur operating expenses and capital revenue requirement expenses inclusive of incremental environmental investments;

(2) Retire Hunter Unit 1 and replace with resource alternatives; or;

(3) Convert to natural gas as a compliance alternative to the incremental environmental investments planned for the unit as a coal-fueled facility.

The results of the comparison of various alternatives resulted in a PVRR(d) of [redacted] favorable to proceeding with the project to the next best alternative as selected by the System Optimizer Model. The next best alternative was to convert Hunter Unit 1 to a natural gas fueled facility. Confidential Exhibit RMP___(CAT-3) provides detailed discussion of the Company's analyses and results.

Q. Are the methods and tools used to assess the compliance alternatives for Hunter Unit 1 consistent with those utilized to support the Company's recent 2013 Integrated Resource Plan filings, as well as the Company's Jim Bridger Units 3 and 4 CPCN filing in Wyoming and its Jim Bridger Units 3 and 4 Voluntary Procurement Pre-approval filing in Utah?

A. Yes. The Company utilized consistent methods and tools (e.g. System Optimizer Model) to assess compliance alternatives for Hunter Unit 1 as has been done in the Company's other recent major filings regarding environmental compliance investments in coal-fueled resources. In fact, the Company has included the results of its Hunter Unit 1 analyses in its 2013 Integrated Resource Plan Confidential Volume III filing.

Q. Does the Hunter Unit 1 baghouse conversion project provide emissions compliance benefits beyond those required by the Utah Regional Haze SIP?

A. Yes. The Hunter Unit 1 baghouse conversion project provides emissions compliance benefits associated with the EPA's MATS regulations.

Q. Beyond directly reducing mercury emissions, how is the Hunter Unit 1 baghouse project expected to allow Hunter Unit 1 to meet other EPA's MATS regulations?

A. In addition to specific emissions requirements for mercury, MATS includes requirements for emissions of non-mercury metals. MATS non-mercury metals emissions compliance can be demonstrated via a surrogate PM emissions limit of 0.030 pounds filterable PM per million Btu. Installation of the baghouse with performance requirements described above will allow Hunter Unit 1 to comply with that portion of MATS.

With respect to mercury emissions control, the Company expects that the Hunter 1 baghouse will allow Hunter Unit 1 to comply with MATS mercury emissions limits without the need for a coal supply additive (and associated costs) to oxidize mercury as the coal is burned in the furnace or the need to install activated carbon injection equipment for mercury removal purposes, avoiding those incremental costs as well.

<u>Hunter Unit 1 Projects Emerging Environmental Regulations Considerations</u>

Q. Has the Company assessed the potential costs of emerging environmental regulations in its economic analyses of the Hunter Unit 1 emissions compliance projects included in this case?

A. Yes. The Company has assessed potential costs of reasonably foreseeable emerging environmental regulations including coal combustion residuals ("CCR") regulations, Clean Water Act Section 316(b) regulations, effluent limitation guidelines, and various CO_2 cost scenarios in its Hunter Unit 1 analyses. Confidential Exhibit RMP___(CAT-3) provides additional detail regarding the Company's analyses in this regard.

Q. Has the Company developed emerging CCR regulations compliance costs for the Hunter facility?

A. Yes. Although information regarding the currently emerging CCR regulations was not available at the time of development of the Utah Regional Haze SIP and planning of the multi-year Hunter Unit 1 projects, the Company is committed to understanding and anticipating the effect of emerging environmental regulations in its economic evaluations and environmental plans. As the Company assesses options regarding continued investment in its coal fueled generation assets, the Company will be faced with certain CCR storage, handling, and long-term management costs at its existing facilities whether the facilities continue to operate or not. Therefore, the Company periodically updates its CCR-related costs and asset retirement obligations in its planning processes. In response to the rulemaking regarding CCR proposed by EPA in June 2010, the Company has updated its CCR-related costs and asset retirement obligations on a preliminary basis to incorporate proposed Subtitle D or near-Subtitle D infrastructure requirements in its business planning processes, which serve as a planning proxy for the Company until such time as EPA completes its CCR rulemaking process. It is currently anticipated that compliance with final CCR rules will be required five years after final rulemaking, or by 2019. Until a final rule is promulgated, the cost, timing, equipment, monitoring, and recordkeeping to comply with the rule cannot be fully ascertained. However, the costs of the Company's proxy CCR Subtitle D compliance projects have been incorporated into the Company's business plans and the economic analyses of the Hunter Unit 1 emissions control investments in this case.

Q. Has the Company developed emerging 316(b) regulations compliance costs for the Hunter facility?

A. Yes. Although information regarding the currently emerging 316(b) regulations was not available at the time of development of the Utah Regional Haze SIP and planning of the multi-year Hunter Units 1 projects included in this case, the Company has applied the same principles as those discussed above for emerging CCR regulations and has incorporated 316(b) compliance costs into the Company's economic analyses and those costs did not alter the outcome.

Q. Has the Company developed emerging effluent limitation guidelines compliance costs for Hunter?

A. The Hunter plant is a zero discharge facility and it is currently not anticipated that it will be materially impacted by the proposed EPA effluent limitation guidelines. As such no proxy compliance costs for emerging effluent limitation guidelines were incorporated into the Company's economic analyses.

Q. How has the Company assessed potential CO_2 regulation outcomes?

A. As further described in Confidential Exhibit RMP___(CAT-3), the Company's Hunter Unit 1 baghouse and LNB investments were assessed over a range of CO_2 and natural gas forward price scenarios.

<u>Hunter Unit 1 Projects Implementation</u>

Q. Did the Company competitively and prudently procure the Hunter Unit 1 baghouse project EPC contract, as well as the Hunter Unit 1 LNB project?

A. Yes. In 2012, the Company issued a competitive EPC contract request for proposals package to over 20 market participants for supply of the Hunter Unit 1 baghouse conversion project. Three viable proposals were received and evaluated on a technical and commercial basis. The best evaluated proposal was identified and an EPC contract awarded following the procurement process.

Q. What emissions performance guarantees are provided via the Hunter 1 baghouse project EPC contract?

A. The baghouse project was specified with contractually guaranteed performance emission threshold at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	**Emissions Limit (lb per MMBtu)**
PM/PM_{10}[(a)]	**0.012**

(a) Filterable portion only

Q. What emissions performance guarantees are provided via the Hunter 1 LNB supply contract?

A. The LNB supply contract includes guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	**Emissions Limit (lb per MMBtu)**
NO_X	**0.24**

Q. What is the current status of the Hunter 1 baghouse project?

A. Engineering and procurement for the baghouse EPC contract are complete, and the major components of the baghouse have been fabricated and delivered to the site. The EPC contractor is currently assembling baghouse components into modules which are installed during the outage. The induced draft booster fans rotors and motors are scheduled for delivery in January 2014. The only remaining material deliveries are the bags and cages for the baghouse which will be received on site by mid-February 2014. Pre-outage construction work began in May 2013 and will be ongoing until the outage starts. Major construction work and baghouse tie-in will be completed during the planned major maintenance outage period. The project is currently forecasted to be completed at or slightly below the approved budget amount, thus ensuring ratepayers will realize the value indicated by the economic analysis.

Q. What is the current status of the Hunter 1 LNB project?

A. Engineering and procurement are complete for the LNB project, and the new burners, ancillary equipment and ductwork are scheduled to start arriving at the Hunter plant in January 2014, and deliveries will be complete by the end of February 2014. Pre-outage construction work began in November 2013 and will be ongoing until the outage starts. Major construction work and LNB tie-in will be completed during the planned major maintenance outage. The project is currently forecasted to be completed at or slightly below the approved budget amount, thus ensuring ratepayers will realize the value indicated by the economic analysis.

Pollution Control Investment Project - Hayden Unit 1

<u>Hayden Unit 1 Project Overview</u>

Q. Please describe the Hayden facility.

A. The Hayden plant is a 446 megawatt, two-unit coal-fired electrical generating facility located in Routt County, Colorado. Unit 1 is jointly owned by Public Service Company of Colorado (“PSCo”) and PacifiCorp (PacifiCorp owns 24.5

percent). Unit 2 is jointly owned by PSCo, Salt River Project, and PacifiCorp (PacifiCorp owns 12.6 percent). PSCo operates the plant.

Hayden Unit 1 Project Drivers and Alternatives Assessments

Q. What are the key permits and/or regulations requiring the Hayden Unit 1 SCR project to be installed?

A. To continue compliant operation of Hayden Unit 1, the PSCo must install the SCR project described herein to control NO_X emissions. In December 2010, the Colorado Air Quality Control Commission ("AQCC") promulgated new BART determinations and emissions control requirements for the Hayden units in the Colorado Regional Haze SIP. These BART determinations set emissions limits of 0.08 lbs NOx/MMBtu for Hayden Unit 1, and 0.07 lbs NOx/MMBtu for Hayden Unit 2. Although the BART determinations did not specify how these limits were to be achieved, installation of SCRs is the only technically feasible method currently available. The Unit 1 SCR is expected to enter service in 2015, and the Unit 2 SCR is expected to enter service in 2016.

EPA published its approval of the Colorado Regional Haze SIP in in the Federal Register on December 31, 2012.

Q. Are the Colorado Regional Haze SIP requirements for Hayden Unit 1 currently being litigated?

A. Environmental groups National Parks Conservation Association and WildEarth Guardians filed petitions for review before the U.S. 10th Circuit Court of Appeals challenging the legality of EPA approving some aspects of the Colorado Regional Haze SIP. In general, the environmental groups are asking the court to require

EPA to make the Colorado Regional Haze SIP more stringent by requiring SCR controls at more units at a faster pace. PacifiCorp, the state of Colorado and other utilities have intervened in the appeal in support of EPA's approval of the Colorado Regional Haze SIP and against the proposition of making it more stringent.

Q. If litigation regarding Hayden Unit 1 environmental compliance requirements were to result in changes to current compliance requirements for the unit, would the Participation Agreement dictate that PSCo re-assess the SCR investment?

A. The environmental groups who filed the litigation are not seeking less stringent controls at Hayden Unit 1. Without that issue specifically before the court, it is highly unlikely that the court's decision will result in a relaxation of the SCR compliance requirements for Hayden Unit 1. If, for some reason, litigation did result in a change in SCR compliance requirements for Hayden Unit 1, the PSCo and the Company would re-assesses such changes pursuant to the terms of the Participation Agreement.

<u>Hayden Unit 1 Ownership Agreement Considerations</u>

Q. What are the primary ownership agreement considerations regarding the Company's investment in the Hayden Unit 1 SCR project?

A. The Participation Agreement requires Hayden Unit 1 to be operated in compliance with all environmental laws. The Participation Agreement also places an independent obligation on Public Service Company of Colorado, as the Operating Agent, to operate Hayden Unit 1 in accordance with all environmental laws. Considerations under the agreement fall into two primary classes. First, PacifiCorp must consider the applicable law (e.g., the Colorado Regional Haze SIP and the Colorado Clean Air Clean Jobs Act). Second, PacifiCorp must consider its contractual rights and obligations under the Participation Agreement in regard to the applicable law.

Q. Following its assessment of applicable law and its rights and obligations under the Participation Agreement for Hayden Unit 1, what position has the Company taken with respect to the SCR emissions control investment for the unit.

A. Following its assessment of applicable law and its rights and obligations under the Participation Agreement, the Company approved investment in the SCR for Hayden Unit 1 because: (i) it is required by applicable law; and (ii) Hayden Unit 1 is required to be operated in accordance with applicable law.

Q. What is the status of applicable law that applies to the Hayden Unit 1 SCR emissions control investment?

A. The state of Colorado promulgated, and the U.S. EPA approved, a Regional Haze SIP for the state of Colorado. Failure to comply with the requirements of a state and EPA approved SIP will likely result in state and/or federal enforcement action, substantial penalties, and a requirement to close the unit until it is brought into compliance.

Further, the state of Colorado has adopted the Clean Air Clean Jobs Act that required PSCo to submit a plan to reduce NO_X emissions by 70 to 80 percent by 2017. PSCo's NO_X reduction plan, reviewed and approved by the Colorado

Public Utilities Commission, includes installation of SCR retrofits on Hayden Units 1 and 2. To comply with the Colorado Regional Haze SIP and PSCo's approved Clean Air Clean Jobs Act NOx reduction plan, PSCo as Operating Agent for the Hayden facility, is pursuing installation of SCR on Hayden Units 1 and 2.

Q. Please provide a general description of the terms and conditions of the Hayden Unit 1 Participation Agreement that governs the Company's rights and obligations regarding major capital expenditures at this jointly owned plant.

A. The Participation Agreement mandates the installation of capital improvements that are required by applicable law. The Participation Agreement also places an independent obligation on PSCo, as Operating Agent, to operate Hayden Unit 2 in accordance with applicable law. Also, the Participation Agreement requires the unanimous consent of all owners to proceed with a capital improvement. If the Operating Agent proposes a capital improvement (e.g. the installation of SCR equipment) to meet applicable law, as has occurred at Hayden Unit 1, a non-consenting owner has the option to assert that the Operating Agent (and other owners) are in default under the Participation Agreement if it cannot be demonstrated that applicable law requires the investment. In that case, whether or not a default has occurred will be decided by arbitration.

Q. Does the Company assert that the Operating Agent for Hayden Unit 1 is in default as it pertains to its proposed capital investment in the installation of SCR equipment on the unit?

A. No. The basis for the Company's position in that regard is provided above.

Q. Did the Hayden Unit 1 Operating Agent and joint owner, PSCo, and the state of Colorado determine that installation of the SCR on the unit was in the best interests of customers?

A. Yes. PSCo has found the installation of SCR on Unit 1 to be in the best interests of customers and has received approval of a CPCN from the Colorado Public Service Commission for the project.

Q. Considering the terms and conditions of the Hayden Unit 1 Participation Agreement, did the Company pursue arbitration of the Hunter Unit 1 SCR investment decision?

A. No, for the reasons explained above.

<u>Hayden Unit 1 Projects Implementation</u>

Q. What is the current status of the Hayden Unit 1 SCR project?

A. Engineering and procurement of the Hayden Unit 1 SCR project are underway, and the SCR equipment supply contract has been awarded. PSCo is completing the Hayden Unit 1 SCR project on a multiple lump sum contracts basis with PSCo staff and PSCo's owner's engineer providing engineering, procurement, and construction management. Major construction work and SCR tie-in will be completed during the planned major maintenance outage period for the unit in spring 2015.

Blundell Geothermal Well Integration Project

Q. Please describe the Blundell facility.

A. The Blundell plant is a 34-megawatt geothermal facility near Milford, Utah. Blundell Unit 1 was commissioned in 1984 and is a 24 megawatt facility using single "flash" technology. Blundell Unit 2 was commissioned in 2007 and is a 10 megawatt "bottoming" cycle which uses a binary heat-recovery process to extract additional energy from the hot geothermal brine left over from Blundell Unit 1 prior to returning the brine to the geothermal reservoir. The renewable energy source for the Blundell plant is the Roosevelt Hot Springs Reservoir which spans approximately 30,000 acres and lays thousands of feet below surface. The reservoir contains groundwater heated by magma to approximately 500°F and at a pressure of approximately 500 pounds per square inch. There are four existing supply wells that bring the high-pressure, heated liquid to the surface, where it "flashes" to steam in steam separators. The steam is separated from the geothermal liquid called "brine" and the steam is transported by above ground pipeline to Blundell Unit 1 which uses a Rankine Cycle steam turbine generator to produce electricity.

Blundell Unit 2 is a "bottoming" cycle. The steam exiting Blundell Unit 1 flows through heat exchangers to heat iso-pentane, a fluid similar to propane, to expand through a separate turbine to generate electricity in a closed-loop, binary process. The geothermal fluid, after passing through the iso-pentane heat exchangers, is further condensed and returned to the geothermal reservoir via three existing injection wells. The plant has approximately two miles of steam piping and six miles of brine piping, tying the existing seven-well geothermal supply and injection system together. With the exception of the geothermal brine, Blundell is a zero-discharge facility.

Q. Please describe the Blundell well integration project.

A. The two wells included in the Blundell well integration project were originally drilled in 2008 as part of a project to prove the Roosevelt Hot Springs Reservoir's capacity and capability to support construction on an incremental generation resource at the facility (Blundell Unit 3). The wells were drilled and tested under the premise that they could ultimately be incorporated into the existing geothermal supply and injection system for Blundell Units 1 and 2, or could ultimately be incorporated into a series of new wells required for an incremental resource at Blundell. Pursuit of an incremental generation resource at Blundell was deferred and later canceled due to cost, inability to commercially mitigate geothermal resource performance risk, and uncertainty regarding renewal of production tax credits for geothermal resources. However, these two new wells represent viable assets that are available to be placed into service for the benefit of customers. The wells will supply additional steam and injection capacity for Blundell Units 1 and 2 and improve operational reliability and flexibility.

Q. Please describe the assets that will be placed into rates.

A. This project will place into service one new steam production well drilled to a depth of approximately 5,000 feet and associated ancillary equipment including a well head, steam/brine separator, emergency backup generator, brine transfer pump, control system, disposal pond, air compressors, well site control/equipment building and security fencing. It will also place into service one new injection well drilled to a depth of approximately 7,000 feet deep and associated ancillary equipment including a wellhead, disposal pond, local instrumentation and valves for operation. The wells are interconnected with Blundell Unit 1 and 2 by three new overland pipelines. One pipeline will connect the production well to the Unit 1 main steam supply line. A second pipeline will connect the production well to the Blundell Unit 2 brine supply line, and the third pipeline will connect Blundell Unit 2 brine return line to the new injection well. In addition, plant control system modifications are required to operate the new production and injection wells from the Blundell Unit 1 control room.

Q. What is the total value of the assets described above and when will they be placed in service?

A. The forecasted costs of the project, including AFUDC, are approximately [redacted] and are expected to be placed in service by September 2014.

Q. How does this project benefit customers?

A. The project will benefit customers by improving the reliability and operational flexibility of Blundell Units 1 and 2.

Q. How has the Company assessed the benefit to customers?

A. The four active production wells at Blundell have an average age of over 30 years. The three active injection wells at Blundell have an average age of over 35 years. Production and injection wells have a finite life which is very difficult to model and predict; however, a statistical analysis of Roosevelt Hot Springs Reservoir well histories indicate a 10 percent per year probability of a well failure. While statistically, an event can happen any time, it has been over 10 years since a significant well event has occurred at Blundell.

Since 1984, two production wells have failed and been abandoned. During that timeframe, three other production wells have developed issues that, while not immediately impairing their serviceability, are being monitored. With the remaining wells in service, reserve steam supply capability at Blundell is currently estimated to be less than eight percent based upon current well conditions and performance assumptions and will continue to decline as the condition of the wells continues to deteriorate. However, during peak demand months in the summer and early fall, the Company has experienced lost production due to lack of steam supply, leading to the conclusion that the reserve margin reported as less than eight percent may be overly optimistic depending upon specific operating conditions. During May through October 2012, Blundell Unit 1 operated at 6,195 megawatt-hours below nameplate capacity as a result of low steam pressure across the four production wells. This realized loss of production capability is a key driver to pursing incremental production well capacity tie-in at this point in time.

If one of the four wells were to fail, there is insufficient capacity in the remaining three production wells to maintain rated plant output. In fact, two of the four production wells deliver approximately 70 percent of the steam for Blundell. If one of those wells were to fail, output would be severely curtailed until the well could be replaced.

Regarding injection wells, the continued production of high pressure geothermal fluid from the Roosevelt resource is contingent on injection of the used geothermal brine back into the aquifer to maintain the fluid balance. The brine cools as it travels down the injection wells, and as it cools the silica suspended in the brine solution turns solid and can plug and ultimately close off the injection capability of the well. While the rate of plugging is difficult to measure, maintaining margin in total system injection well capacity to accommodate individual well performance degradation is prudent.

Of the three existing injection wells, one well is suspected to be re-injecting fluid near or just outside the limit of the geothermal field due to gradually changing subsurface characteristics of the resource, one has a partially collapsed casing and the third injection well is used to re-inject most of the fluid. Thus plant production is currently heavily dependent on a single injection well.

Based on the approximate 20-year remaining life of Blundell and a range of probabilities and circumstances, the benefit for integration of the two wells ranges from [redacted] to [redacted] on an annualized basis, with a total benefit over the remaining life of Blundell of [redacted] to [redacted].

Q. Can the Company wait to complete the Blundell well integration project?

A. No. With the increasing risk of failure due to deteriorating condition of the production and injection wells described above, as well as the realization of loss of available energy production in 2012 due to existing well conditions, pursuing integration of the production and injection wells available at Blundell is appropriate at this time. As noted above, if the Company were to wait until ultimate failure of a well prior to commencing procurement of ancillary equipment supply and installation contracts, it is reasonable to assume that the lost production and/or injection well capacity would extend 12 months or more, based upon the competitively procured equipment supply lead times and installation contract schedules currently being negotiated by the Company.

While accelerated equipment supply and installation agreements may ultimately be available in an "emergency" condition, such contracts would be reasonably expected to be significantly more costly and would not address ongoing loss of energy generation during the delivery and installation period.

Naughton Unit 3 Natural Gas Conversion Project

Q. Please describe the Naughton plant and the Naughton Unit 3 facility, in particular.

A. The Naughton plant consists of three coal fueled units that are all 100 precent owned and operated by PacifiCorp. PacifiCorp also owns 100 precent of the Viva Naughton reservoir which stores water for consumptive use at the Naughton plant and provides regional recreation opportunities. Water for plant use flows from the Viva Naughton reservoir into the Ham's Fork River, where it is diverted approximately five miles downstream and then conveyed approximately nine miles via a pipeline to an onsite raw water storage pond. National Pollutant Discharge Elimination System ("NPDES") permit WY0020311 allows release of small flows from CCR clearwater ponds. Plant sewage is treated on site in a general biosolids permitted package wastewater treatment facility that discharges effluent into a CCR pond under NPDES permit WY0020311. Potable water for plant use is obtained from the town of Kemmerer, Wyoming.

The Naughton plant property is adjacent to the Westmoreland Kemmerer Mine that supplies approximately 2.8 million tons per year of sub-bituminous coal to the plant via an overland belt conveyor. CCR are disposed of on plant property in surface impoundments.

Naughton Unit 3 began commercial operation in 1971. It has a currently approved depreciable life for ratemaking purposes of 2029, and a net reliable generation capacity of 330 megawatts ("MW"). The boiler was retrofitted in 1999 with LNB for NO_X removal. The unit configuration also includes: a closed-loop cooling water system, with a mechanical draft cooling tower; an electrostatic precipitator ("ESP") for PM removal; and a sodium-based wet flue gas desulfurization system ("FGD") for SO_2 removal that was retrofitted in 1981.

The Naughton plant currently employs approximately 140 personnel, including approximately 105 union craft personnel represented by the International Brotherhood of Electrical Workers Local 57.

Q. Please describe the Naughton Unit 3 natural gas conversion project and the associated equipment.

A. As part of the Naughton Unit 3 natural gas conversion project, the steam electric unit will be converted from a base-loaded 100 percent coal fueled unit to a 100 percent natural gas fueled slow-start peaking unit. Coal fueling equipment will be left in place except where it interferes with new natural gas fuel supply equipment. It is anticipated that natural gas supply piping to the converted Naughton Unit 3 can be modified with a new pipeline, approximately 16 inches in diameter, from the existing natural gas supplier metering station located approximately 1.8 miles east of the plant.

New boiler natural gas fuel supply equipment will include igniters, flame scanners, LNBs, and natural gas distribution piping. Five levels of LNBs will be installed in existing air compartments on each of the four corners of the boiler and will have the capability to sustain unit operation over a net reliable load range from approximately 85 to 330 MW. Modifications to the boiler burner management control systems will be completed. New process control instruments, control wiring and high performance controller modules will be installed and integrated into the plant's existing distributed control system.

A 15 to 20 percent flue gas recirculation system ("FGR") will be installed to enable the boiler to attain required operating temperatures and to provide NOx emissions reductions. Flue gas will be recirculated from the existing ductwork between the economizer outlet and the air preheater inlet. Flue gas will be re-injected into the boiler wind box. The FGR will consist of two by 50 percent capacity fans; including lubricating oil systems, fan motors, foundations, vibration monitoring, controls and interconnecting ductwork.

Flue gas will exit the unit by flowing through: (1) the de-energized existing ESP, (2) the existing induced draft and booster fans, and (3) the FGD bypass ductwork. It will discharge to the atmosphere through the existing wet FGD chimney. All flue gas duct expansion joints between the induced draft fan inlets and the FGD outlet duct will be replaced. Other demolition work will be limited to interfering items only.

Q. Why is natural gas conversion of Naughton Unit 3 being pursued?

A. To comply with state of Wyoming Regional Haze SIP requirements, installation of SCR and a baghouse to reduce emissions of NO_X and PM on Naughton Unit 3 was required by December 31, 2014. The Company assessed the economics associated with these requirements in a CPCN docket in the state of Wyoming and determined that natural gas conversion is in the best interests of the Company's customers. A summary of the Company's CPCN filing and results is included in Exhibit RMP___(CAT-4).

Q. Please provide additional background regarding the Regional Haze compliance obligations facing Naughton Unit 3.

A. In 2007, the Company submitted required applications to the Wyoming Department of Environmental Quality ("WDEQ") Air Quality Division ("AQD") for BART permits at various BART-eligible electric generating units in Wyoming, including Naughton Unit 3. On December 31, 2009, the WDEQ AQD issued BART permit MD-6042 for the Naughton plant requiring, among other things, the installation of a SCR and a baghouse as additional environmental controls at Naughton Unit 3.

In February 2010, the Company appealed certain provisions of the Naughton BART permit to the Wyoming Environmental Quality Council ("WEQC"), including provisions requiring the installation of SCR and baghouse on Naughton Unit 3. By settlement agreement dated November 3, 2010, the Company and the WDEQ AQD resolved the appeal as to Naughton Unit 3 by the Company agreeing to abide by the original terms of the Naughton BART permit.

The WDEQ AQD finalized its Regional Haze SIP on January 7, 2011, including the requirement for the Company to install a SCR and baghouse at Naughton Unit 3. It then submitted its Regional Haze SIP to the EPA for review and approval. On June 4, 2012, EPA proposed to partially approve certain portions of the Wyoming Regional Haze SIP, including those portions that require the installation of SCR and baghouse at Naughton Unit 3 by December 31, 2014.

The EPA later determined that public comments received on its proposed action on the SIP led it to *re-propose* its rule for a new round of public comment. The EPA reported that it had conducted additional analysis on emissions control costs and the associated visibility benefits between the Wyoming Regional Haze SIP submittal and December 14, 2012, the anticipated EPA final action date. The EPA approached the original litigants and, in an unopposed motion filed December 10, 2012 with the U.S. Department of Justice on behalf of the EPA, requested a new deadline for a re-proposed rule of March 29, 2013, and a final action deadline of September 27, 2013. The court approved the EPA's request for extension on December 13, 2012.

Subsequently, on March 27, 2013, the EPA received approval from the U.S. District Court to again extend the deadlines previously agreed to for issuance of actions on the Wyoming Regional Haze SIP. In a filing made in the U.S. District Court, WildEarth Guardians, National Parks Conservation Association, and the Environmental Defense Fund agreed to allow the EPA to extend the previously extended deadlines for issuance of a re-proposal on the Wyoming Regional Haze SIP from March 29, 2013 to May 23, 2013, and to revise final action deadlines from September 27, 2013 to November 21, 2013.

The EPA re-proposed official draft rules on the Wyoming Regional Haze SIP on June 10, 2013. In its re-proposed draft rules, the EPA supported SCR and baghouse on Naughton Unit 3 and requested public comments on a natural gas conversion alternative. The Company provided comments on the EPA's re-drafted proposal on August 26, 2013, in support of the natural gas conversion alternative for Naughton Unit 3 and extension of the operating timeframe of the unit as a coal-fueled resource from December 31, 2014 to December 31, 2017.

Since August 26, 2013, EPA has again been granted an extension to take final action on the Wyoming Regional Haze SIP to January 10, 2014. Until EPA takes final action on the SIP, and the underlying state of Wyoming compliance obligations, including the Wyoming Regional Haze SIP, are modified, the Company remains obligated to comply the Wyoming Regional Haze SIP and the associated WDEQ permit documents to install SCR and a baghouse at Naughton Unit 3 by December 31, 2014.

Q. Did the Company explore compliance flexibility, if any, with the environmental agencies having jurisdiction (i.e. state of Wyoming and/or EPA)?

A. Yes. The topic of project timelines and technical requirements has been raised with representatives of the state of Wyoming and EPA Region 8 given EPA's continual extension motions regarding Wyoming Regional Haze SIP actions, and consideration that final action is now not expected until January 10, 2014. The Company has pointed out that re-proposed rules, after dates the Company must enter into contracts for timely and compliant equipment procurement and installation, affecting required emissions limits or compliance timelines make cost-effective decision-making and planning extremely difficult both for the Company and for competitive market participants. Further, due to EPA's continually delayed action, it would be impossible for the Company to complete an SCR and baghouse project within the originally prescribed compliance deadline for Naughton Unit 3, should the EPA reject the alternative compliance approach of natural gas conversion of the unit. EPA has acknowledged the dilemma to the Company and competitive market faces.

Company representatives also met WDEQ representatives on January 4, 2013 and March 27, 2013, to further discuss EPA's delayed action along with other environmental compliance planning topics. WDEQ's position regarding EPA's pending actions is that the Company is currently bound by the environmental compliance obligations included in the Wyoming Regional Haze SIP, associated WDEQ AQD permits, and settlement stipulation pertaining to Naughton Unit 3 and other Wyoming units. The WDEQ re-confirmed its position in writing on March 6, 2013.

Company representatives also met with the Wyoming Attorney General's office on January 4, 2013, to discuss deadlines and the agency's position on extending the deadlines. The Company was advised that the state of Wyoming views the deadlines as being independently legally enforceable under the Wyoming Regional Haze SIP, the Settlement Agreement, and Chapters 6 and 9 of the Wyoming Air Quality Standards and Regulations. The state's position was confirmed at the WEQC's meeting on January 10, 2013.

Q. Has the Company formally requested state of Wyoming approval of the natural gas conversion alternate Regional Haze compliance approach for Naughton Unit 3?

A. Yes. Recognizing the complexity that attempting to modify Wyoming Regional Haze SIP, Settlement Agreement, and other associated regulations and agreements regarding Naughton Unit 3 presents; as well as the uncertainty surrounding the timing and extent of EPA's final action in this regard, the Company applied for and received a permit from the WDEQ to cease coal-fueled operation of Naughton Unit 3 by December 31, 2017, and to convert the unit to natural gas fueling by June 30, 2018. WDEQ AQD Permit MD-14506 is attached as Exhibit RMP___(CAT-5) for reference.

It is expected that the terms of the natural gas conversion permit for Naughton Unit 3 will ultimately be aligned with the other Regional Haze related plans, permits, and agreements affecting the unit following final EPA action on the Wyoming Regional Haze SIP.

Q. Has the Company evaluated whether the least-cost alternative, accounting for risk and uncertainty, to comply with environmental requirements was to invest in the emissions control equipment or to idle Naughton Unit 3?

A. Yes. As part of the CPCN process described above, the Company completed an economic analysis that evaluated the trade-offs between making incremental investments to comply with then-current and emerging environmental regulations to a broad range of resource alternatives including: (1) natural gas conversion; (2)

early retirement and replacement with green field natural gas resources; (3) firm market purchases; (4) demand-side management opportunities; and or (5) renewable resources. Ultimately, the Company's evaluation established that converting the unit to 100 percent natural gas fueling and operating the unit as a slow-start peaking unit was the risk-adjusted and least-cost alternative for our customers.

Q. **Did the Company consider alternative technologies to the natural gas conversion?**

A. Yes. Exhibit RMP___(CAT-2) is a summary of the technical studies and key study points used in the Company's consideration and analysis of technical alternatives to the Naughton Unit 3 Regional Haze compliance alternatives.

Q. **Please describe the currently anticipated Naughton Unit 3 natural gas conversion project timeline from inception through final completion.**

A. This testimony has been prepared under the worst-case assumption that the Naughton Unit 3 natural gas conversion will be completed and placed in service by May 2015, pursuant to the currently established Wyoming Regional Haze SIP compliance deadline for Naughton Unit 3 NO_X and PM reductions, and assuming that EPA does not support the timeline for conversion approved under the state of Wyoming construction permit discussed above. Under this scenario, the unit would operate on coal through December 31, 2014, and subsequently enter into a five-month construction and tie-in outage for conversion of the unit to natural gas as its fuel supply. EPC contract provisions are being pursued that will guarantee the project to be mechanically complete by June 1, 2015, and available thereafter to generate as dispatched during the 2015 summer peak load season and beyond.

Exhibit RMP___(CAT-6) illustrates the overall project timeline from inception to completion, including activities occurring during the early development phase of the project that were focused toward planning a SCR and a baghouse alternative instead of the natural gas conversion alternative.

Q. Has the Company aligned its competitive procurement activities for the conversion project with the emissions performance requirements of the construction permit approved for the project?

A. Yes. PacifiCorp is currently in the process of bidding the EPC contract for the Naughton Unit 3 natural gas conversion. Proposals were received from bidders on December 3, 2013. In its request for proposals, PacifiCorp requested the following emissions performance guarantees:

Parameter	**Guarantee**
NOx Emission Rate	**By Contractor** **(At least ≤ 0.080 lb NOx/mmBtu throughout the load range)**
Long Term NOx Emission Rate	**< 0.080 lb NOx/mmBtu AND < 250 lb NOx/hr** **(30-boiler day rolling arithmetic average)**
CO	**By Contractor** **(lb CO/mmBtu or ppm throughout the load range)**
VOC Emission	**< 0.0040 lb VOC/mmBtu**
PM Limit	**≤ 0.0070 lb PM_{10}/mmBtu**

Q. Did the Company consider all applicable emerging environmental regulations that pose risk to continued operation of Naughton Unit 3 when determining natural gas conversion was the preferred compliance alternative?

A. Yes. The Company considered MATS regulations; potential carbon dioxide (“CO_2”) regulations; proposed CCR regulations; proposed Clean Water Act 316(b) regulations; and proposed effluent limitation guidelines rulemaking. Case-by-case discussion of the impacts of those emerging environmental regulations on the Company’s decision to convert Naughton Unit 3 to a natural gas fueled generation resource is provided in Exhibit RMP___(CAT-7) for reference.

Q. Does the Naughton Unit 3 natural gas conversion permit issued by Wyoming address MATS compliance for the unit in the interim between April 15, 2015 and December 31, 2017?

A. Yes. A critical consideration of the Naughton Unit 3 natural gas conversion compliance schedule approved by WDEQ is the overlapping requirement to comply with MATS by April 16, 2015, through the December 31, 2017, coal-fueled operation window for the unit. In that interim period, WDEQ has prescribed enforceable operating restrictions and emissions limits on the unit consistent with MATS compliance requirements. It is proposed that the operating limits and permit conditions commence upon compliance dates required by the MATS rule (April 16, 2015), and terminate December 31, 2017.

Q. Has the EPA approved the alternate Regional Haze compliance approach of converting Naughton Unit 3 to natural gas fueling?

A. No. As discussed above, EPA is not currently expected to take final action on the Wyoming Regional Haze SIP until January 10, 2014. EPA has, however, requested public comment on the Naughton Unit 3 natural gas conversion and associated project timing approved by Wyoming. As such, the Company continues to prepare for the earlier conversion date discussed above to avoid placing the Company in a position of being unable to achieve the currently prescribed Wyoming Regional Haze SIP compliance timeline for the unit.

Q. Are the state of Wyoming compliance requirements enforceable absent final EPA action?

A. Yes. Company representatives met with WDEQ representatives on January 4, 2013 and March 27, 2013, to further discuss the EPA's delayed Wyoming Regional Haze SIP rule making action along with other environmental compliance planning topics. WDEQ's position regarding EPA's pending actions is that the Company remains currently bound by the environmental compliance obligation included in the Wyoming Regional Haze SIP, associated WDEQ AQD permits, and settlement stipulation pertaining to Naughton Unit 3 and other Wyoming units. The WDEQ re-confirmed its position in writing on March 6, 2013. See Exhibit RMP___(CAT-8).

Q. If EPA approves the revised compliance deadline for Naughton Unit 3 consistent with the state of Wyoming's requirements, what actions does the Company intend to take?

A. If EPA approves the Naughton Unit 3 compliance conditions included in the construction permit issued by WDEQ discussed above and allows the unit to operate as a coal-fueled resource through December 31, 2017, the Company will revise its natural gas conversion project implementation schedule accordingly. In that instance, the Company would support an adjustment to the capital cost associated with the natural gas conversion project and removing the capital addition from the Test Period. The impact of such an adjustment is addressed in the direct testimony of Company witnesses Mr. Gregory N. Duvall and Mr. Steven R. McDougal. Exhibit RMP___(CAT-9) provides additional context regarding permitting activities associated with EPA's review and approval.

Q. Will Naughton Unit 3 remain a low cost generation resource following implementation of the project?

A. While the implementation phase of the Naughton Unit 3 natural gas conversion has not yet started, the EPC contract is currently being bid for an early 2015 conversion. The competitive market respondents to the Company's request for proposals further inform the Company as to whether its cost estimates and performance assumptions for the project remain accurate and aligned with the assumptions used in its Naughton Unit 3 natural gas conversion alternative resource decision analysis.

The Company's current economic analysis, including sensitivity analyses, for the proposed Naughton Unit 3 natural gas conversion project demonstrates that the unit remains a valuable low cost generation resource for peaking needs following unit conversion.

Conclusion

Q. Please summarize your testimony.

A. The Lake Side 2 project was approved by the Commission as the lowest reasonable cost option to meet additional electricity needs of customers, taking into account costs and risks, in Docket No. 10-035-126. The Company's investment in and implementation of the new Lake Side 2 CCCT natural gas fueled resource project remains aligned with its original intent and is expected to deliver benefits to customers on schedule and at a lower capital cost than originally forecasted.

Investments in emissions control investments at the Company's jointly owned Hunter Unit 1 and Hayden Unit 1 are required to meet the EPA's Regional Haze rules, and the resulting BART reviews, state implementation plans, permitting processes, and in the case of Hayden, Colorado Clean Air Clean Jobs Act. The investments in pollution control equipment at the Company's Hunter Unit 1 included in this case have been assessed in conjunction with potential compliance costs associated with emerging environmental regulations, including potential regulation of carbon dioxide emissions. The investment allows for the continued operation of low-cost coal-fueled generation resources, while achieving significant environmental improvements. The Company's support of the investment in the Hayden Unit 1 environmental compliance project included in this case has been administered pursuant to applicable law and the Partnership Agreement applicable to that unit.

The Company's other major generation plant investments at Blundell and as currently planned at Naughton Unit 3 have been prudently managed and assessed as being in the best interests of customers; effectively maintaining safe, reliable, efficient, cost-effective generating resources and production facilities.

The capital investments included in this case are reasonable and prudent, and the Company should be granted full cost recovery for these investments.

Q. Does this conclude your direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(CAT-1)
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Chad A. Teply

History of Hunter 1 Regional Haze Compliance Obligations

January 2014

History of Hunter 1 Regional Haze Compliance Obligations

When discussing efforts to establish environmental compliance schedules for PacifiCorp's coal-fueled resources, including Hunter Unit 1, it is imperative to understand the fact that Regional Haze compliance strategies for units across the western U.S. (including Hunter and Huntington) were established via a collective agency, industry and stakeholder approach beginning around the 1999 timeframe (i.e. Western Regional Air Partnership), and with the Regional Haze Rules as they generally exist today promulgated and adopted by the agencies in 2005. Therefore, PacifiCorp's efforts to influence appropriate compliance technologies, compliance deadlines and installation schedules for its individual units affected by Regional Haze Rules began years ago. As a participant in the Western Regional Air Partnership (WRAP) process, the Utah Division of Air Quality established requirements that pollution control equipment, including the installation of the baghouse and LNBs at Hunter 1, would be installed by 2013 (i.e., the end of the 2008 to 2013 Regional Haze Rules BART planning period). PacifiCorp's participation in the WRAP process and Regional Haze planning activities resulted in identifying appropriate emissions control technologies and establishing equipment installation schedules that met the requirements of the state of Utah for Hunter and Huntington and occurred during the units' normally scheduled major overhauls to minimize costs by reducing overall unit down-time and power purchases necessitated by additional outages.

With respect to PacifiCorp's specific efforts to negotiate deferred installation of emissions control equipment on Hunter Unit 1, delays associated with obtaining an approval order and finalizing the Utah Regional Haze State Implementation Plan in the 2008 timeframe made it extremely difficult for PacifiCorp to cost-effectively install the required equipment during the unit’s 2010 overhaul, which would have allowed the equipment to be installed in alignment with Utah Regional Haze compliance timeframe requirements prior to 2013. As a result of negotiations with the Utah Division of Air Quality, the Company was allowed to delay the installation of the control equipment on Hunter Unit 1 until the unit’s 2014 overhaul. As part of the agreement to delay the installation of the control equipment, PacifiCorp was required to submit semi-annual reports to the state beginning in 2010 demonstrating that continual progress towards completing the installation by 2014 is occurring, and that certain annual emission rates are being met.

With the negotiated 2014 compliance deadline for the baghouse and LNB projects, PacifiCorp completed detailed economic analysis of the Hunter Unit 1 compliance investments in 2012 prior to entering into engineering, procurement, and construction contracts for the multi-year project, incorporating then-current assumptions for forward gas prices, forward market prices, and proxy compliance costs for emerging environmental regulations with the potential to impact the unit. The results of PacifiCorp’s economic analyses completed in the 2012 timeframe (and included in Confidential Volume III of the Company’s 2013 IRP filing) support investment in the environmental compliance projects, even when considering the reasonably anticipated and generally quantifiable uncertainties regarding emerging environmental compliance obligations for the unit, and continued operation of this low cost resource through its depreciable life.

As has been demonstrated by the EPA's continually delayed and deferred actions regarding Regional Haze Rule action in the state of Wyoming, and with a similar process playing out regarding EPA's delayed and deferred actions on Utah Regional Haze Rule administration, neither Utah nor Wyoming has waited to implement their Regional Haze State Implementation Plans. Instead each state has delivered upon the plans they developed within the construct of the Regional Haze Rules and established timely and enforceable requirements for PacifiCorp's units affected by the rules. The concept of negotiating away compliance obligations while waiting for certainty regarding a myriad of emerging environmental policies and ever changing market conditions is not an approach that the states of Utah and Wyoming have engaged in, particularly without state policy drivers targeting accelerated retirement of the affected low cost resources in question.

Rocky Mountain Power
Exhibit RMP___(CAT-2)
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Chad A. Teply

Summary of Alternate Compliance Technology Studies

January 2014

Summary of Alternate Compliance Technology Studies

The Company completed eight noteworthy technical studies to evaluate NOx, PM and SO_2 emission control alternative technologies for Naughton Unit 3, the first of which also apply to the Hunter Unit 1 projects included in this docket for review. In October 2002, Sargent and Lundy ("SL") completed a fleet-wide *Multi-Pollutant Control Report* as an attorney-client privileged work product; in January 2005, SL completed a NOx emissions reduction technologies study; in March 2006, SL completed a *Conceptual Design of Replacement Baghouse PacifiCorp Naughton* 3 study; in February 2007, CH2M Hill completed the *BART Analysis for the Naughton Unit 3*; in December 2009, SL completed the *SCR and Baghouse Study Report*; in October 2012, Alstom completed the *Naughton Unit 3 Engineering Study to Evaluate 100% Gas Firing Fuel Heat Input*; in November 2012, SL completed the *Naughton Station Conversion of Unit 3 to 100% Natural Gas Firing* study; and in March 2013, Alstom completed the *Naughton Unit 3 Engineering Study to Evaluate 100% Gas Fuel Input Including Evaluation of Flue Gas Recirculation and Low Load Operation.*

1. The *Multi-Pollutant Control Report* provided an early investigation of the cost and necessity of NOx, particulate matter ("PM") and sulfur dioxide ("SO_2") emission controls on the units.
2. The 2005 NOx emission reduction technologies study compared sixteen emission control technologies, status of the technology development, predicted performance, approximate initial capital costs, and approximate incremental fixed and variable operational and maintenance ("O&M") costs.

3. The *Conceptual Design of Replacement Baghouse PacifiCorp Naughton 3* study established initial capital costs for PM emissions control alternatives.
4. The *BART Analysis for the Naughton Unit 3* was conducted for criteria pollutants NOx, PM_{10} and SO_2. The Company conducted the BART analysis and determination to analyze the effects on visibility in nearby Class I areas (Bridger, Fitzpatrick and Mt. Zirkel Wilderness Areas). A BART analysis is a comprehensive evaluation of potential NOx, PM and SO_2 retrofit technologies, and a BART determination is an emissions limit established by the application of potential retrofit technologies for each unit. The specific steps in a BART analysis are established in 40 CFR 51 Appendix Y, Section IV. The analysis must include: (1) the identification of available and technically feasible retrofit alternatives; (2) consideration of any pollution control equipment in use at the source (which affects the availability of alternatives and their effects); (3) the costs of compliance with control alternatives; (4) the remaining useful life of the facility; (5) the energy and non-air quality environmental impacts of compliance; and (6) the degree of visibility improvement that reasonably may be anticipated from installation of the BART alternative.
5. The *SCR and Baghouse Study Report* evaluated and established design criteria and specified critical equipment features to mitigate design risks for a SCR and baghouse technology alternative.
6. The *Naughton Unit 3 Engineering Study to Evaluate 100% Gas Firing Fuel Heat Input* assessed the boiler thermal performance impacts; firing system

performance and emissions impacts; controls impacts; and potential boiler pressure part and firing system component modifications that may be required to add natural gas firing capability to the unit based on operation with 100% fuel heat input at full load.

7. The *Naughton Station Conversion of Unit 3 to 100% Natural Gas Firing* study investigated the scope of work and estimated costs for converting the unit from a base loaded coal unit to a natural gas fueled peaking unit while leaving coal firing capability intact to the greatest extent practicable.
8. The *Naughton Unit 3 Engineering Study to Evaluate 100% Gas Fuel Input Including Evaluation of Flue Gas Recirculation and Low Load Operation* assessed thermal performance of the unit at low load and provided an evaluation of NOx emissions control using a FGR alternative at both high and low loads.

Key Study Points

Salient points from these eight studies, and related information from other sources, are presented with following statements:

The *Multi-Pollutant Control Report* indicated that combination "in-combustion" (Low NOx Burners with Over Fire Air) and "post combustion" (Selective Catalytic Reduction) would need to be installed on Hunter Unit 1 to achieve a presumptive NOx emission rate of less and 0.10 pounds per million British thermal units (lb/mmBtu)

The *Multi-Pollutant Control Report* indicated that a combination of "in-combustion" and "post-combustion" controls (namely a SCR) would need to be installed on Naughton Unit 3 to achieve a presumptive NOx emissions limit of less than 0.10 pounds per million British thermal units ("lb/mmBtu").

The *Multi-Pollutant Control Report* indicated that the Hunter Unit 1 ESP could achieve a particulate emission level of 0.030 lb/mmBtu with reasonable modifications and upgrades, and it further indicated that that maintenance costs would need to increase over time to facilitate the rebuilds necessary to keep the current equipment operational at historic levels. In order to achieve an emission level below 0.020 lb/mmBtu, the *Multi-Pollutant Control Report* indicated a polishing baghouses retrofit would need to be completed.

The *Multi-Pollutant Control Report* indicated that Naughton Unit 3 would require extensive modifications to the existing ESP or a "polishing baghouse retrofit" must be completed to meet a presumptive PM emissions limit of less than 0.030 lb/mmBtu. The Naughton Unit 3 ESP is the smallest in the Company's coal fleet, is about 40 years old, and is in poor condition. It does have a flue gas conditioning system to improve its performance. Historical operating data establishes that the existing ESP's best PM emissions rate is only approximately 0.04 lb/mmBtu.

The *Multi-Pollutant Control Report* indicated that the Hunter Units 1 FGD system could achieve a removal efficiency of 90% with the following system upgrades: (1) close the scrubber bypass damper (2) upgrade the existing mist eliminators (3) add vertical flow mist eliminators (4) improve inlet gas distribution (5) upgrade existing reheat system (6) upgrade spray header and nozzle system (7) replace existing spray pumps (8) convert to a forced oxidation system (9) restore and upgrade dewatering equipment.

The *Multi-Pollutant Control Report*, and other sources, indicated that a FGD upgrade SO_2 removal efficiency of 90% would be achieved on the existing Naughton Unit 3 FGD with only minor changes including: (1) improvements to the inlet gas distribution; (2) the liquid to gas contact point would need to be reviewed; (3) reagent and waste delivery systems needed to be upgraded; (4) a reagent adjustment; and (5) consideration of a conversion to an open spray type absorber.

At units with high baseline NOx emissions (high is defined here as being greater than 0.40 lb/mmBtu), it is common utility industry practice to initially obtain a NOx emissions reduction through the installation in-combustion modifications, similar to the LNBs installed on the units, and then control the remainder of any required NOx emissions reduction with post-combustion control systems, typically either SCR or a selective non-catalytic reduction system ("SNCR").

NOx control technologies are grouped as either *in-combustion* control, *post-combustion* control or *emerging* types:

- In-Combustion Controls include: (1) LNBs with overfire air ("OFA"); (2) more precise combustion control of fuel and air; (3) combustion optimization using a Neural Network system; and (4) Nalco Mobotec rotating opposed fire air ("ROFA" or "rotating opposed fire air") which is a next generation OFA system.

- Post-Combustion Controls include: (1) SNCR, typically limited to only 10 to 40 percent NOx emissions reduction and have higher ammonia slip rates; and (2) SCR with 80 to 90 percent NOx emissions reduction and a low ammonia slip rate.
- Other emerging NOx reduction technologies (and that might become commercially available, or more commercially feasible, within the next decade) with the capability to achieve required NOx removal percentages include: (1) Regenerative Activated Coke Technology; (2) Powerspan Electro-Catalytic Oxidation; (3) BOC LoTOx System; (4) Airborne Process; (5) Consolv Technologies Absorption Process; (6) Lean Gas Reburning; (7) Rich Reagent Injection; (8) SNCR plus SCR hybrid systems; (9) Aptech CST SNCR type systems; and (10) other reagent injection developments.

Of the technology alternatives mentioned herein, only LNB with OFA, ROFA, SNCR with LNB, and SCR with LNB were considered BART analysis feasible alternatives for NOx reduction across the fleet.

In a SCR, ammonia ("NH_3") reacts with NOx contained in the flue gas exiting the boiler as either nitrogen oxide ("NO") or nitrogen dioxide ("NO_2") in the presence of catalyst to form molecular nitrogen ("N_2") and water ("H_2O"). Catalyst enhances the reaction between ammonia and NOx. The injected air-diluted ammonia is adsorbed on the catalyst surfaces in the SCR reactors and reacts with oxygen and NOx present in the flue gas according to the following chemical reaction equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

SNCR technology is similar to SCR because it involves injection of an amine reducing agent like urea solution. The reduction chemistry, however, takes place in the boiler without the aid of any catalyst. SNCR relies on appropriate injection temperatures, proper mixing of the reagent and flue gas, reagent injection kinematics, and prolonged boiler detention time in place of the catalyst. SNCR operate at higher temperatures than SCR. The effective temperature range for SNCR is 1,600 to 2,100 degrees F. SNCR is sensitive to temperature changes.

Table NT3-5-1 summarizes a comparison of NOx emissions control technologies results adapted from the *BART Analysis for the Naughton Unit 3* on a 2007 cost year basis: Other environmental project costs not included in the BART estimates include: boiler and air preheater casing structural reinforcements, flue gas path structural reinforcement, a high and low temperature EEGT control system, demolition, auxiliary power system upgrades, Owner’s project costs and a contingency allowance.

Table NT3-5-1: Oxides of Nitrogen Emissions Control Technologies Comparison (Adapted From CH2M Hill BART Analysis)

Technology	Projected Emission Rate (lb/mmBtu)	Projected Emission % Reduction (%) (b)	Capital Cost ($ x million)	O&M Cost Fixed + Variable ($ x million)	Annual Power Usage (1,000 MWh/yr)	First Year Avg. Cost For NOx Removal ($/ton)
Baseline	0.50 (a)	0%	0.0	0.0	0.0	0
LNBs with OFA	0.35	22.2%	0.0 (c)	0.1	0.0	0
ROFA	0.28	37.8%	14.7	1.9	35.3	1,326
Selective Non-Catalytic Reduction and LNBs with OFA	0.28	37.8%	15.8	0.9	2.6	984
Selective Catalytic Reduction and LNBs with OFA	0.07	84.4%	92.0	2.6	15.7	2,049

(a) Emissions from PI data in table below; prior to LNB and OFA installations on Unit 3, the uncontrolled emissions rate was approximately 0.50 lb/mmBtu
(b) Technology reduction rates from the CH2M Hill BART analysis shown
(c) Currently installed on Naughton Unit 3

The baseline NO_X concentration of 0.50 lb/mmBtu was established from Naughton Unit 3 performance historian (“PI”) data and confirmed with continuous emissions data and flue gas testing.

PM emissions control technologies evaluated for Naughton Unit 3 include: (1) install a stand-alone baghouse to replace the existing ESP; (2) install a polishing fabric filter (Compact Hybrid Particulate Collector or (“COHPAC”)) to operate in series with the existing ESP; (3) rebuild the existing ESP; and (4) replace the existing ESP with a Reversing Gas Fabric Filter (“RGFF”), which is a PM cleaning device currently not often selected for use in steam electric plants.

Feasible technical alternatives to meet a PM emissions compliance limit of 0.015 lb/mmBtu are: (1) install a polishing baghouse and operate it in series with a rebuilt ESP; and (2) install a stand-alone baghouse. The *Design of Replacement Baghouse PacifiCorp Naughton 3* study established initial capital costs in 2006 dollars for these two alternatives.

The *Naughton Unit 3 Engineering Study to Evaluate 100% Gas Firing Fuel Heat Input* reported that the unit can be converted from the current coal firing configuration and made capable to operate at full load on 100% natural gas without significant boiler equipment or pressure part modifications. NOx emissions of approximately 0.09 to 0.12 lb/mmBtu were predicted with natural gas firing, consequently indicating it would be necessary to install a post-combustion SNCR process or other post-combustion NOx control process if a NOx emissions limit of approximately 0.08 lb/mmBtu is required. An alternative FGR was proposed instead of adding a post-combustion NOx control system. The FGR can simultaneously achieve the desired NOx emissions limit at 0.08 lb/mmBtu while also achieving design steam temperatures more easily and over a broader load range. Alstom offered an opinion that potential furnace modifications that include FGR and or waterwall refractory alternatives would provide greater flexibility for NOx and carbon monoxide (“CO”) control when firing 100% natural gas, and would be necessary from a performance standpoint if the boiler were to be operated at low loads.

The *Naughton Unit 3 Engineering Study to Evaluate 100% Gas Fuel Input Including Evaluation of Flue Gas Recirculation and Low Load Operation* reported that Naughton Unit 3 can be converted from the current coal firing configuration and made capable to operate at full load on 100% natural gas without significant boiler or pressure part modifications. The addition of a FGR is required to mitigate steam temperature reductions when attempting to attain required NOx emissions at full load. A FGR is also required to maintain high final reheat steam temperatures at a low load of approximately 85 MW. Alstom reported an FGR operated at about 20% FGR at full load, operated in conjunction with Alstom's recommended natural gas firing system and the existing SOFA system, is predicted to result in a NOx emissions range of 0.06 to 0.09 lb/mmBtu and a CO emissions rate at less than 0.15 lb/mmBtu.

Beyond the eight studies discussed above, The EPSCO International, Inc., *Phase III Recommendations* study of the Hunter and Huntington electrostatic precipitators (ESP) was used as the basis for the decision to convert the Hunter Unit 1 ESP to a baghouse. The decision making process began when the same type of conversion was made at Huntington Unit 2 (2004-2006). The ESP at Hunter Unit 1 and Unit 2 and Huntington Unit 1 and Unit 2 are identical and in 2003 it had become apparent that the ESP's were having operational difficulties. EPSCO International, Inc. was hired to study the situation, identify options and make recommendations for the Huntington and Hunter units. The EPSCO report titled *Phase III Recommendations* was published in November 2003.

CONFIDENTIAL
Rocky Mountain Power
Exhibit RMP___(CAT-3)
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Confidential Exhibit Accompanying Direct Testimony of Chad A. Teply

Hunter 1 System Optimizer Model Financial Analysis
Memorandum, May 11, 2012

January 2014

THIS EXHIBIT IS CONFIDENTIAL AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Rocky Mountain Power
Exhibit RMP___(CAT-4)
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Chad A. Teply

Naughton Unit 3 CPC Docket Summary

January 2014

Naughton Unit 3 CPCN Docket Summary

As a result of the Company's 2011 Wyoming general rate case Docket No. 20000-384-ER-10, the Company is obligated to participate in a pre-project implementation certificate of public convenience and necessity ("CPCN") approval process and public review of certain planned major environmental projects in the state of Wyoming via a "Stipulation and Agreement" effective on June 6, 2011. The signatory parties to the Stipulation and Agreement included: Rocky Mountain Power; the Wyoming Office of Consumer Advocate; Wyoming Industrial Energy Consumers; QEP Field Services Company; Cimarex Energy Company; Interwest Energy Alliance; AARP Wyoming; City of Casper, Wyoming; Town of Mills, Wyoming; Town of Bar Nunn, Wyoming; Town of Midwest, Wyoming; Natrona County, Wyoming; Granite Peak Development, LLC; Kinder Morgan Interstate Gas Transmission LLC; Utility Workers Union of America, Local 127; AFL-CIO; and Power River Basin Resource Council.

On September 16, 2011, the Company applied to the Public Service Commission of Wyoming ("Commission") for an Order granting a CPCN to construct environmental compliance investments in a SCR and baghouse on Naughton Unit 3. On April 9, 2012, the Company filed rebuttal testimony and updated information in the proceeding, based on an updated analysis undertaken in response to changing market conditions and testimony filed by interveners, showing that the SCR and baghouse investments on Naughton Unit 3 are no longer cost-effective and that the interest of the Company and its customers would be best served by alternatively converting Naughton Unit 3 to a slow-start 100%

natural gas fueled peaking unit. The Company's updated analysis showed that the natural gas conversion was the risk-adjusted, least-cost compliance alternative when compared to the mandated SCR and baghouse (and other available options) using updated economic model input assumptions, updated market information and advancements in modeling methodology. The Wyoming Commission issued an Order granting the Company's motion to withdraw its CPCN application for SCR and baghouse on July 19, 2012.

In the Company's updated analysis, results from the System Optimizer ("SO") Model base case optimized simulation selected the natural gas conversion alternative, and in doing so, chose to avoid the SCR and baghouse project, and other environmental upgrades planned for Naughton Unit 3. The present value revenue requirement difference ("PVRR(d)") between the base case optimized simulation and the change case simulation showed that the natural gas conversion alternative was [redacted] favorable to the SCR and baghouse, and other environmental upgrades required for Naughton Unit 3 to continue operating as a coal-fueled facility. Additional sensitivity analysis around the base case analysis showed that the asset life and on-going operating cost assumptions ranges do not alter the updated base case results supporting natural gas conversion as the risk-adjusted, least-cost alternative to the SCR and baghouse investment at Naughton Unit 3. Key factors that changed in the Company's updated analysis included:

- Updates to the Company's base case natural gas price assumptions in response to lower observed forward market price and lower longer term natural gas price forecasts from third party experts.

- Updates and expansion of natural gas and carbon dioxide (“CO_2”) sensitivity scenarios that are based upon a review of third party projections and that included varying combinations of natural gas and CO_2 price assumptions.
- Updates to the SO Model that incorporated a comprehensive assumption review process, aligning modeling assumptions with the Company’s 2012 business plan and addressing issues by interveners.

SCR and Baghouse EPC Contract

In parallel with the CPCN proceedings described above, the Company competitively bid and negotiated an EPC contract associated with the SCR and baghouse during the period of December 23, 2010 (request for proposal release date) to December 8, 2011 (effective date of EPC contract). To comply with a December 31, 2014 compliance obligation, and given the uncertain outcome the CPCN proceeding at the time, the EPC contract was structured with a *limited* notice to proceed (“LNTP”) concept and a *full* notice to proceed (“FNTP”) authorization. The FNTP date was established as September 30, 2012. As a result of the Company’s updated analysis in the CPCN proceeding, the EPC contract was suspended on February 27, 2012, during the LNTP period and ultimately terminated by the Company for convenience on December 31, 2012.

Naughton Unit 3 Deferred Accounting Docket

On May 3, 2012, the Company made application to the Public Service Commission of Utah under Docket No. 12-035-80, for an accounting order authorizing the Company to record a regulatory asset for the project development and LNTP phase costs incurred in the amount of approximately [redacted]

[redacted]. The costs were incurred in support of the anticipated project critical path schedule and included cost items associated with internal project development work; Owner's engineering consulting work; permitting applications and fees; design basis technical studies; Rocky Mountain Power interconnection costs; and early EPC contract detailed engineering, project execution planning and subcontracted site assessments. In its application, the Company specifically requested the Utah Commission to approve transfer of approximately [redacted] out of FERC Account 107 (Construction Work in Progress or "CWIP") and record a regulatory asset in FERC Account 182.3 (Other Regulatory Assets) that would be amortized over two years starting in the Company's next general rate case. The state of Utah's share of the regulatory asset would be established based on the system generation ("SG") allocation factor, resulting in an allocated amount of approximately $3.4 million. The Company did not request a final decision on rate recovery through its application in Docket No. 12-035-80 and proposed rate recovery of the Regulatory Asset in its next general rate case, and that amortization begin in that test period.

On August 7, 2012, the Company filed a settlement agreement and associated motions in the 2012 Utah general rate with the Utah Commission. The settlement agreement included a proposal to resolve the Naughton Unit 3 SCR and baghouse project development and LNTP phase cost deferral Docket No. 12-035-80. The Utah Commission issued an order on September 19, 2012, in a consolidated 2011 general rate case and two deferred accounting cases for decommissioning the Carbon plant and recovery of the Naughton Unit 3 SCR and baghouse project development and LNTP phase costs. In the settlement agreement, the parties agreed to defer and amortize the Naughton Unit 3 SCR and baghouse project development and LNTP phase costs by September 1, 2014, thereby providing full recovery to the Company prior to the effective date of new rates resulting from the 2014 general rate case.

Rocky Mountain Power
Exhibit RMP___(CAT-5)
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Chad A. Teply

DEQ Letter dated July 5, 2013

January 2014

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Matthew H. Mead, Governor

Todd Parfitt, Director

July 5, 2013

Mr. William K. Lawson
Environmental Manager
PacifiCorp Energy
1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

CERTIFIED – RETURN RECEIPT REQUESTED

Re: Air Quality Permit No. MD-14506

Dear Mr. Lawson:

The Division of Air Quality of the Wyoming Department of Environmental Quality has completed final review of PacifiCorp Energy's application to modify the Naughton Power Plant by reducing permitted emissions from Unit 3 and ultimately converting the unit from a coal-fired electric generating unit to a natural gas-fired unit in 2018. The Naughton Plant is located in sections 32 and 33, T21N, R116W, approximately four (4) miles southwest of Kemmerer, in Lincoln County, Wyoming. Comments were received from PacifiCorp Energy on June 14, 2013; and on June 17, 2013 from the United Mine Workers of America Local 1307; from Westmoreland Kemmerer, Incorporated; and from the Lincoln Conversation District. All comments were considered in the final permit and are addressed below.

Comments from the United Mine Workers of America Local 1307; Westmoreland Kemmerer, Incorporated; and the Lincoln Conservation District

Comments: The United Mine Workers of America Local 1307 and Westmoreland Kemmerer, Incorporated oppose the permitting action that would allow the conversion of Naughton Unit 3 to a natural gas-fired unit. Both commenters state that controls could be used on the existing unit to achieve compliance with EPA standards. Both commenters also cite the potential reduction in the workforce at the Kemmerer Mine, reduction in tax revenue, and a potential loss of school district funding as the reasons for their opposition. The Lincoln Conservation District commented that the price of natural gas could rise in the future, which could increase rates for electricity from gas-fired units. They also cite the potential loss of tax revenue and impact to local budget cuts, and concur that pollution controls could be used on the existing coal-fired unit to achieve compliance with EPA standards.

Responses: The Division grants air quality permits for the construction or modification of air pollution sources based on compliance with the Wyoming Air Quality Standards and Regulations. The Division does not dictate fundamental design of the applicant's facility or the applicant's choice of fuels or the cost of those fuels. We do not have the authority to deny an air quality permit for a proposed project because of a project's impact on tax revenue or the local economy. We do consider the costs of the air pollution control equipment that is proposed for the facility, but only to ensure that Best Available Control Technology (BACT) is being applied in accordance with the WAQSR.

PacifiCorp Energy's Comments

Comment: Permit Conditions 6.ii.4 and 10 – PacifiCorp stated that it intends to implement the requirements imposed by Condition 6.ii beginning April 1, 2015, and requests that Conditions 6.ii.4 and 10 be revised to require that initial performance testing be completed within 30 boiler operating days from April 1, 2015. PacifiCorp also notes that Condition 10 refers to limits contained in Condition 5.ii that are actually stated in 6.ii.

Response: The Division will retain the effective date of the emission limits shown in 6.ii.4, but will revised the timeframe for initial performance testing from April 1, 2015 to within 30 boiler operating days from April 1, 2015 in accordance with Chapter 6, Section 2(j) of the Wyoming Air Quality Standards and Regulations (WAQSR). Condition 10 will be revised to correctly refer to the limits in Condition 6.ii rather than 5.ii.

Comment: Permit Conditions 6.iii.4 and 11 – PacifiCorp intends to complete the conversion of Unit 3 and place the unit in service as a natural gas unit prior to June 30, 2018. Therefore, the requirement that initial performance testing for limits under 6.iii.4 be complete by December 31, 2017 cannot be met. PacifiCorp also notes that Condition 11 refers to limits contained in Condition 5.iii that are actually stated in 6.iii.

Response: The Division's intent in requiring testing under Condition 6.iii.4 by December 31, 2017 was to ensure that Unit 3 would not be fueled by coal beyond that date, as represented in the application. To allow PacifiCorp the time needed to make the conversion of Unit 3 to a natural gas-fired unit, the Division will extend the initial performance testing requirement to 90 calendar days following startup of the unit on natural gas. The Division will require that the coal pulverizers for Unit 3 be removed from service no later than January 1, 2018, in accordance with PacifiCorp Energy's comment, to ensure that Unit 3 does not operate on coal during the conversion to a natural gas-fired unit. Condition 11 will be revised to correctly refer to the limits specified in Condition 6.iii rather than 5.iii.

Comment: Permit Conditions 6.iii.2 and 11.i.2 - PacifiCorp requests that the 2-hour rolling average limit and the 3-hour block average limit for SO_2 be removed. PacifiCorp also requests that the requirement to determine SO_2 emissions using a continuous emissions monitoring system (CEMS) be replaced with a method using gas flow and an emissions factor from 40 CFR part 75.

Response: The Division will not grant these requests without a demonstration on the part of the applicant that the remaining emissions limits for SO_2 will allow for the same level of air quality protection as the limits that are requested for removal. The SO_2 limits for Naughton Unit 3 will remain as proposed. If PacifiCorp Energy provides a demonstration to revise the SO_2 limits, then the Division will consider revising the applicable monitoring requirements based on the averaging period of the determined limits.

Comment: Permit Conditions 13.i.1 and 13.i.3 - PacifiCorp requests that the 30-day and 12-month rolling average emission limits be based on the summation of hourly emissions divided by the summation of hourly heat input for the same time period.

Response: The Division will retain the methods specified in Conditions 13.i.1 and 13.i.3 to define exceedances of the emission limits as they are consistent with existing methods specified in other air quality permits for the Naughton Plant. The Division does not anticipate that the requested methods would yield results appreciably different from those produced by the methods required in the draft permit.

Comment: Permit Condition 20 - PacifiCorp intends to complete the conversion of Unit 3 and place the unit in service as a natural gas unit prior to June 30, 2018, therefore they request that Condition 20 be modified to reflect that the conversion must be completed prior to June 30, 2018, and that initial performance tests be completed within 90 days of initial startup on natural gas.

Response: The Division's intent in requiring the conversion of Unit 3 and initial testing by December 31, 2017 was to ensure that Unit 3 would not be fueled by coal beyond that date, as represented in the application. To allow PacifiCorp the time needed to make the conversion of Unit 3 to a natural gas-fired unit, the Division will extend the initial performance testing requirement to 90 calendar days following the startup of the unit on natural gas. The Division will require that the coal pulverizers for Unit 3 be removed from service no later than January 1, 2018 to ensure that Unit 3 cannot operate on coal during the conversion to a natural gas-fired unit.

If we may be of further assistance to you, please feel free to contact this office.

Sincerely,

Steven A. Dietrich

Steven A. Dietrich
Administrator
Air Quality Division

cc: Greg Meeker

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Matthew H. Mead, Governor

Todd Parfitt, Director

July 5, 2013

Mr. William K. Lawson
Environmental Manager
PacifiCorp Energy
1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

Permit No. **MD-14506**

Dear Mr. Lawson:

The Division of Air Quality of the Wyoming Department of Environmental Quality has completed final review of PacifiCorp Energy's application to modify the Naughton Power Plant by reducing permitted emissions from Unit 3 and ultimately converting the unit from a coal-fired electric generating unit to a natural gas-fired unit in 2018. The Naughton Plant is located in sections 32 and 33, T21N, R116W, approximately four (4) miles southwest of Kemmerer, in Lincoln County, Wyoming.

Following this agency's proposed approval of the request as published May 16, 2013 and in accordance with Chapter 6, Section 2(m) of the Wyoming Air Quality Standards and Regulations, the public was afforded a 30-day period in which to submit comments concerning the proposed modification, and an opportunity for a public hearing. Comments were received and considered in the issuance of the final permit. Therefore, on the basis of the information provided to us, approval to modify the Naughton Power Plant as described in the application is hereby granted pursuant to Chapter 6, Section 2 of the regulations with the following conditions:

1. That authorized representatives of the Division of Air Quality be given permission to enter and inspect any property, premise or place on or at which an air pollution source is located or is being constructed or installed for the purpose of investigating actual or potential sources of air pollution and for determining compliance or non-compliance with any rules, standards, permits or orders.

2. That all substantive commitments and descriptions set forth in the application for this permit, unless superseded by a specific condition of this permit, are incorporated herein by this reference and are enforceable as conditions of this permit.

3. PacifiCorp Energy shall file a complete application to modify their Operating Permit within twelve (12) months of commencing operation, in accordance with Chapter 6, Section 3(c)(i)(B) of the WAQSR.

4. All notifications, reports and correspondence associated with this permit shall be submitted to the Stationary Source Compliance Program Manager, Air Quality Division, 122 West 25th Street, Cheyenne, WY 82002 and a copy shall be submitted to the District Engineer, Air Quality Division, 510 Meadowview Drive, Lander, WY 82520.

5. For the conversion of Naughton Unit 3 to natural gas, the owner or operator shall furnish the Administrator written notification of: (i) the anticipated date of initial startup not more than 60 days or less than 30 days prior to such date, and; (ii) the actual date of initial start-up within 15 days after such date in accordance with Chapter 6, Section 2(i) of the WAQSR.

6. This condition shall supersede portions of Condition 5 of Air Quality Permit MD-11725 as it pertains to Naughton Unit 3. Condition 5, Unit 3, Condition i. of MD-11725 shall remain in effect. Emissions from Naughton Unit 3 shall not exceed the levels below:

Unit 3

ii. Effective April 1, 2015:
   1. NO_x: 0.75 lb/MMBtu; 3-hour rolling average
      0.40 lb/MMBtu; 30-day rolling average
      1,258.0 lb/hr; 30-day rolling average
      4,700 tons per calendar year
      a. Limits shall apply during all operating periods.
   2. SO_2: 0.5 lb/MMBtu; 2-hour rolling average
      0.20 lb/MMBtu; 30-day rolling average
      1,850 lb/hr; 3-hour block average
      629.0 lb/hr; 30-day rolling average
      2,350 tons per calendar year
      a. Limits shall apply during all operating periods.
   3. PM: 0.035 lb/MMBtu
      110.0 lb/hr
      434.0 tons per calendar year
      a. Filterable PM/PM_{10}
      b. lb/hr limit shall apply during all operating periods.
      c. lb/MMBtu shall apply during all operating periods, except startup.
         i. Startup begins with the introduction of natural gas into the boiler and ends no later than the point in time when the ESP reaches a temperature of 225°F.
   4. Limits in (ii.) above supersede limits in MD-11725, Condition 5(i.) for Unit 3 on and after April 1, 2015. Initial performance tests required by Condition 10 of this permit shall be completed within 30 boiler operating days of April 1, 2015.

iii. Effective upon conversion to natural gas:
   1. NO_x: 0.75 lb/MMBtu; 3-hour rolling average
      0.08 lb/MMBtu; 30-day rolling average
      250.0 lb/hr; 30-day rolling average
      519.0 tons per calendar year
      a. Limits shall apply during all operating periods.
   2. SO_2: 0.5 lb/MMBtu; 2-hour rolling average
      0.0006 lb/MMBtu; 30-day rolling average
      1,850 lb/hr; 3-hour block average
      2.0 lb/hr; 30-day rolling average
      4.0 tons per calendar year
      a. Limits shall apply during all operating periods.

3. PM: 0.008 lb/MMBtu
   30.0 lb/hr
   52.0 tons per calendar year
   a. Total PM/PM_{10}
   b. Limits shall apply during all operating periods.
4. Limits in (iii.) above supersede limits in (ii.) of this condition for Unit 3 on and after January 1, 2018. Initial performance tests required by Condition 11 of this permit shall be completed within 90 calendar days of startup after conversion to natural gas.

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7. Effective upon permit issuance, this condition shall supersede Condition 6(i) of Air Quality Permit MD-11725. Opacity shall be limited as follows:

   i. Units 1-2:
      1. No greater than forty percent (40%) opacity of visible emissions.
         a. Limit shall apply during all operating periods.

      Unit 3:
      1. No greater than twenty percent (20%) opacity for visible emissions.
         a. Limit shall apply during all operating periods.
         b. Limit shall become effective upon startup of Unit 3 after natural gas conversion and completion of initial performance tests required by Condition 11 of this permit.

8. Effective upon permit issuance, this condition shall supersede Condition 10 in MD-9861.

   i. Authorization for SO_3 injection on Unit 3 shall remain in effect until start-up of Unit 3 after natural gas conversion and completion of the initial performance tests required by Condition 11 of this permit.

9. Effective upon permit issuance, this condition shall supersede Condition 17 in MD-5156. PacifiCorp Energy shall not be required under MD-5156 to install, calibrate, operate, and maintain a PM continuous emissions monitoring system (CEMS) on Unit 3.

10. Within 30 boiler operating days of April 1, 2015, performance tests shall be conducted on Unit 3 to demonstrate compliance with the limits in Condition 6.ii. and a written report of the results shall be submitted. If the maximum allowable heat input rate established in Condition 15 is not achieved during the performance tests, the Administrator may require testing be done at the rate achieved and again when the maximum allowable rate is achieved. Performance tests shall consist of the following:

    i. Unit 3:

       1. <u>NO_x Emissions</u> – Compliance with the NO_x 3-hour and 30-day rolling averages shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

2. SO_2 Emissions – Compliance with the SO_2 2-hour and 30-day rolling averages and 3-hour block average shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

3. PM/PM_{10} Emissions – Testing shall follow EPA Reference Test Methods 1-4 and 5, or an equivalent EPA Reference Method.

Testing required by the Chapter 6, Section 3, Operating Permit or required by 40 CFR part 63, subpart UUUUU may be submitted to satisfy the testing required by this condition.

11. Effective upon permit issuance, the applicable requirements of this condition shall supersede Condition 11.ii.2.(Unit 3) of MD-5156. Within 90 calendar days of conversion of Unit 3 to natural gas performance tests shall be conducted on Unit 3 to demonstrate compliance with the limits in Condition 6.iii. of this permit and a written report of the results shall be submitted. If the maximum allowable heat input rate established in Condition 15 of this permit is not achieved during the performance tests, the Administrator may require testing be done at the rate achieved and again when the maximum allowable rate is achieved. Performance tests shall consist of the following:

i. Unit 3:

1. NO_x Emissions – Compliance with the NO_x 3-hour and 30-day rolling averages shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

2. SO_2 Emissions – Compliance with the SO_2 2-hour and 30-day rolling averages and 3-hour block average shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 75.

3. PM/PM_{10} Emissions – Testing shall follow EPA Reference Test Methods 1-5 and 202, or an equivalent EPA Reference Method.
4. CO Emissions - Testing shall follow EPA Reference Test Methods 1-4 and 10 or an equivalent EPA Reference Method.

Testing required by the Chapter 6, Section 3, Operating Permit or required by 40 CFR part 63, subpart UUUUU may be submitted to satisfy the testing required by this condition.

12. Prior to any testing required by this permit, a test protocol shall be submitted to the Division for approval, at least 30 days prior to testing. Notification should be provided to the Division at least 15 days prior to any testing. Results of the tests shall be submitted to this office within 45 days of completing the tests.

13. This condition shall supersede Condition 8 of Air Quality Permit MD-11725 as it applies to Naughton Unit 3. Compliance with the NO_x and SO_2 limits for Naughton Unit 3 set forth in Condition 5(i.) of MD-11725 and Condition 5 of this permit shall be determined with data from the NO_x and SO_2 continuous monitoring systems required by 40 CFR Part 75 as follows:

    i. Exceedances of the limits shall be defined as follows:

        1. Any 12-month rolling average which exceeds the lb/MMBtu NO_x limits as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n}(C)_h}{n}$$

Where:

E_{avg} = Weighted 12-month rolling average emission rate (lb/MMBtu).

C = 1-hour average SO_2 or NO_x emission rate (lb/MMBtu) for hour "h" calculated using valid data from the CEM equipment certified and operated in accordance with Part 75 and the procedures in 40 CFR part 60, appendix A, Method 19. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours monitored during a boiler operating day in the last twelve (12) successive calendar months with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

        2. Any 12-month rolling average which exceeds the lb/hr NO_x limit as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n}(C)_h}{n}$$

Where:

E_{avg} = Weighted 12-month rolling average emission rate (lb/hr).

C = 1-hour average emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment certified and operated in accordance with Part 75. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours monitored during a boiler operating day in the last twelve (12) successive calendar months with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

3. Any 30-day rolling average which exceeds the lb/MMBtu SO_2 or NO_x limit as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n} (C)_h}{n}$$

Where:

E_{avg} = Weighted 30-day rolling average emission rate (lb/MMBtu).

C = 1-hour average emission rate (lb/MMBtu) for hour "h" calculated using valid data from the CEM equipment certified and operated in accordance with Part 75 and the procedures in 40 CFR part 60, appendix A, Method 19. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours in the last thirty (30) successive boiler operating days with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

4. Any 30-day rolling average which exceeds the lb/hr SO_2 or NO_x limits as calculated using the following formula:

$$E_{avg} = \frac{\sum_{h=1}^{n} (C)_h}{n}$$

Where:

E_{avg} = Weighted 30-day rolling average emission rate (lb/hr).

C = 1-hour average emission rate (lb/hr) for hour "h" calculated using valid data (output concentration and average hourly volumetric flowrate) from the CEM equipment certified and operated in accordance with Part 75. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). Valid data shall not include data substituted using the missing data procedure in subpart D of Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

n = The number of unit operating hours in the last thirty (30) successive boiler operating days with valid emissions data meeting the requirements of WAQSR, Chapter 5, Section 2(j). A "boiler operating day" shall be defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

5. Any 3-hour rolling average of NO_x emissions calculated using data from the CEM equipment required by 40 CFR part 75 which exceeds the lb/MMBtu limit established in this permit using valid data. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 3-hour average emission rate shall be calculated as the arithmetic average of the previous three (3) operating hours.

6. Any 2-hour rolling average of SO_2 emissions calculated using data from the CEM equipment required by 40 CFR part 75 which exceeds the lb/MMBtu limit established in this permit using valid data. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 2-hour average emission rate shall be calculated as the arithmetic average of the previous two (2) operating hours.

7. Any 3-hour block average of SO_2 emissions calculated using data from the CEM equipment required by 40 CFR part 75 which exceeds the lb/hr limit established in this permit using valid data. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j). The 3-hour average emission rate shall be calculated at the end of each 3-hour operating block as the arithmetic average of hourly emissions with valid data during the previous three (3) operating hours.

ii. PacifiCorp will comply with all reporting and record keeping requirements as specified in WAQSR, Chapter 5, Section 2(g).

iii. Exclusion of startup, shutdown, and malfunction emissions only applies to federal standard(s) as authorized in the respective subpart and as authorized in this permit.

14. Effective April 1, 2015, Naughton Unit 3's hourly heat input shall be limited to 3,145 MMBtu/hr, based on a 24-hour block average defined as any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit. Compliance with the heat input limit will be determined using a 40 CFR Part 75 certified CEMS and the procedures for determining heat input per 40 CFR Part 75.

15. Effective January 1, 2018, Naughton Unit 3's heat input shall be limited to 12,964,800 MMBtu based on 12-month rolling average of hourly heat input values. Compliance with the heat input limited will be determined using a 40 CFR Part 75 certified CEMS and the procedures for determining heat input per 40 CFR Part 75.

16. Effective upon permit issuance, this condition shall supersede Condition 5.ii of Air Quality Permit MD-11754.

ii. PAL limits effective upon completion of initial performance tests required by Condition 11.

1. NO_x: 5,402.4 tons per year

a. Limit is based on a 12-month rolling total.

b. Initial compliance shall be determined 12 months after the effective date of the PAL. The effective date is the first day of the next month following completion of the initial performance tests required after the completion of natural gas conversion and startup of Unit 3. PacifiCorp Energy shall continue to demonstrate compliance with the NO_x PAL of 11,112.8 tons per year until the initial compliance date for the modified NO_x PAL is triggered.

2. SO_2: 2,862.2 tons per year
   a. Limit is based on a 12-month rolling total.
   b. Initial compliance shall be determined 12 months after the effective date of the PAL. The effective date is the first day of the next month following completion of the initial performance tests required after the completion of natural gas conversion and startup of Unit 3 and. PacifiCorp Energy shall continue to demonstrate compliance with the SO_2 PAL of 8,789.8 tons per year until the initial compliance date for the modified SO_2 PAL is triggered.

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17. Unit 3 shall be equipped with in-stack continuous emission monitoring (CEM) equipment to monitor CO emissions:

    i. CO CEM shall be installed and certified within ninety (90) days of permit issuance.

    ii. PacifiCorp Energy shall install, calibrate, operate, and maintain a monitoring system, and record the output, for measuring CO emissions discharged to the atmosphere in units of ppm_v, lb/MMBtu, and lb/hr. The CO monitoring system shall consist of the following:

        1. A continuous emission CO monitor located in the stack of Unit 3.

        2. A continuous flow monitoring system for measuring the flow of exhaust gases discharged into the atmosphere.

        3. An in-stack oxygen or carbon dioxide monitor for measuring oxygen or carbon dioxide content of the flue gas at the location CO emissions are monitored.

    iii. Each continuous monitor system listed in this condition shall comply with the following:

        1. Monitoring requirements of WAQSR, Chapter 5, Section 2(j) including the following:

            a. 40 CFR part 60, appendix B, Performance Specification 4 or 4a for carbon monoxide. The monitoring systems must demonstrate linearity using 40 CFR part 60, appendix F, and be certified in concentration (ppm_v) and units of lb/MMBtu and lb/hr.

            b. Quality Assurance requirements of 40 CFR part 60, appendix F.

            c. PacifiCorp Energy shall develop and submit for the Division's approval a Quality Assurance plan for each monitoring system listed in this condition. Quality Assurance plans shall be submitted within 180 days from startup of each unit after new low NO_x burners have been installed.

    iv. The CO monitor may be removed after December 31, 2017, upon Division approval.

18. Annually, as otherwise specified by the Administrator, Unit 3 shall be tested to verify compliance with the PM limits set forth in Condition 6. The first annual test is required the following calendar year after completion of the initial performance test required by Condition 10. Testing for PM shall be conducted in accordance with EPA Reference Methods 1-5 and 202, or an equivalent EPA Reference Method. A test protocol shall be submitted to this office for review and approval prior to testing. Notification of the test date shall be provided to the Division fifteen (15) days prior to testing. Results of the tests shall be submitted to the Division within forty-five (45) days of completing the tests.

19. Records required by this permit shall be maintained for a period of at least five (5) years and shall be made available to the Division upon request.

20. PacifiCorp Energy shall remove the coal pulverizers on Unit 3 from service no later than January 1, 2018. PacifiCorp Energy shall provide written notification to the Division of the actual date of pulverizer removal within 30 days of such date.

21. PacifiCorp Energy shall complete the conversion of Naughton Unit 3 to natural gas prior to June 30, 2018, and conduct the initial performance tests required in Condition 11 of this permit no later than 90 calendar days after initial startup of Unit 3 after natural gas conversion.

22. This condition shall become effective upon start-up of Naughton Unit 3 after conversion to natural gas, as reported in accordance with Condition 5 of this permit, and shall supersede Air Quality Permit MD-11894 for the Naughton Plant.

23. All conditions from previously issued Air Quality Permits MD-5156, MD-9861, and MD-11725 shall remain in effect unless specifically superseded by a condition of this permit.

It must be noted that this approval does not relieve you of your obligation to comply with all applicable county, state, and federal standards, regulations or ordinances. Special attention must be given to Chapter 6, Section 2 of the Wyoming Air Quality Standards and Regulations, which details the requirements for compliance with Conditions 5, 10 and 11. Attention must be given to Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations, which details the requirements for compliance with Condition 3. Any appeal of this permit as a final action of the Department must be made to the Environmental Quality Council within sixty (60) days of permit issuance per Section 16, Chapter I, General Rules of Practice and Procedure, Department of Environmental Quality.

If we may be of further assistance to you, please feel free to contact this office.

Sincerely,

Steven A. Dietrich

Steven A. Dietrich	Todd Parfitt
Administrator	Director
Air Quality Division	Dept. of Environmental Quality

cc: Greg Meeker

Rocky Mountain Power
Exhibit RMP___(CAT-6)
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

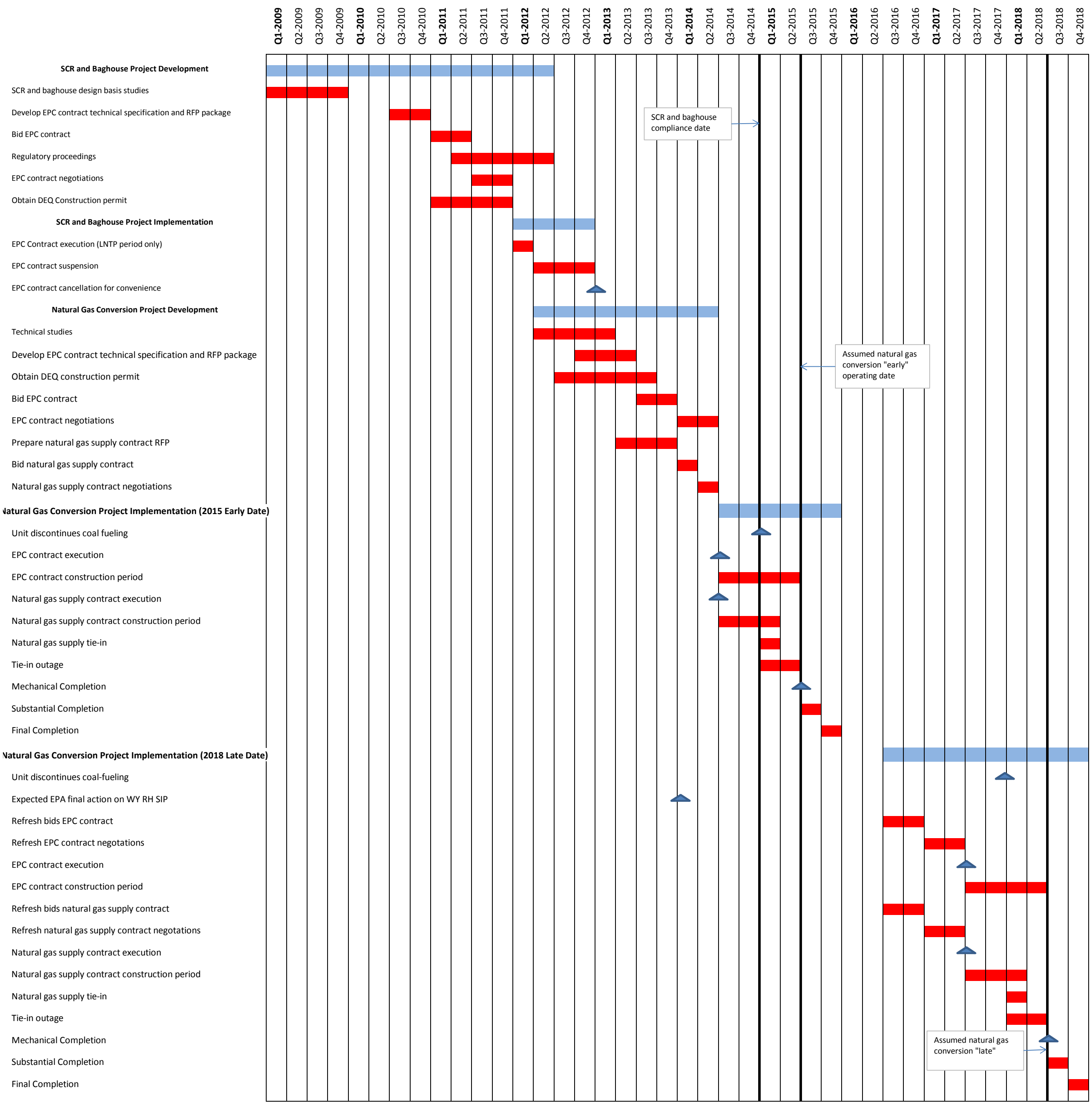
ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Chad A. Teply

Naughton Unit 3 Natural Gas Conversion Schedule

January 2014

Exhibit CAT - 6: Naughton Unit 3 Natural Gas Conversion Schedule



Rocky Mountain Power
Exhibit RMP___(CAT-7)
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Chad A. Teply

Impact of Emerging Environmental Regulations
on Naughton Unit 3 Decision-making

January 2014

Impact of Emerging Environmental Regulations on Naughton Unit 3 Decision-making

Mercury and Air Toxic Standards

To effectuate extended operation of a coal fueled Naughton Unit 3 beyond April 16, 2015 (effective date of the MATS rule), will require a MATS compliance plan for the unit. The MATS standard requires compliance with three emission limits.

The output of Naughton Unit 3 will be restricted from the effective date (April 16, 2015) of the MATS rule through December 31, 2017 as the unit continues to be coal fueled. The interim operating restriction and emissions will be managed by imposing enforceable operating and emissions limits.

The MATS emission limits and compliance requirements as published in the February 16, 2012 *Federal Register* are:

- Mercury (“Hg”) - Hg not to exceed 1.2 pounds per trillion British thermal units (‘lb/TBtu”) based on the average of 30-boiler operating days.
- Non-mercury metals - emit less than 0.030 lb/mmBtu for front-half PM or a combined emission rate of 0.000050 lb/mmBtu for the total specific metals identified in the standard.
- Acid gases - emit less than 0.20 lb/mmBtu SO_2 or emit less than 0.0020 lb/mmBtu for hydrogen chloride (“HCl”).

Naughton Unit 3, based on the Company’s recent testing, can meet the acid gases MATS limit, but will have difficulty meeting the mercury and non-mercury metals MATS limits without additional equipment and/or derating of the unit.

Multiple units at a plant site are allowed under the MATS rule to be averaged together to demonstrate compliance with individual emissions limits. For mercury, averaging would require the plant-wide average mercury emissions to be less than 1.0 lb/TBtu. Compliance parameters for non-mercury metals and acid gases would not change with a plant-wide averaging approach. Based on the potential to average Naughton Unit 3 emissions with those from Naughton Units 1 and 2, tests were performed in March and April of 2012 to understand how the emissions rates changed between these units. Unfortunately, Naughton Unit 1 was off-line, and only Units 2 and 3 were tested.

Mercury

While specific testing of mercury emissions reduction equipment/systems has not been completed at Naughton, current unit performance and mercury emissions testing at the Company's Jim Bridger plant provides confidence that mercury compliance can be achieved through the installation of a coal oxidizer system combined with a FGD additive system on Naughton Unit 3, similar to what is anticipated for Naughton Units 1 and 2. Current mercury emissions are close to complying with the federal standard without additives. While the older Naughton Units 1 and 2 will install a permanent system, a temporary system would be installed on Naughton Unit 3 to minimize costs for a system only expected to be in service for approximately three years.

Non-mercury Metals

Recent testing at Naughton Units 2 and 3 was completed as various loads. Results indicate that non-mercury metals MATS limits will be difficult to meet at full load and will be subject to considerable variability due to difficulty in reliably measuring trace elements, limiting confidence in maintaining compliance. After April 16, 2015, it will be necessary to demonstrate compliance with the non-mercury MATS through quarterly emission tests that may be difficult to meet in either direct measurements on Unit 3 or averaging with all units on the plant site. It will be difficult to meet the non-mercury metals MATS limit on Unit 3 without averaging this unit's emissions with the emissions from Units 1 and 2. Potential ramifications for failing to pass a quarterly test could involve a combination of fines and equipment additions to insure future compliance. Putting Naughton Units 1 and 2 at risk of failure to comply with the non-mercury metals MATS limit by averaging them with Unit 3 was not recommended.

A comparison of PM testing completed in March 2012 was compared to testing done in April 2012. The data indicates that there is considerable variability in the measured PM emissions even when the tests are conducted only a month apart. This variability raises significant concerns with the unit's ability to consistently meet the PM MATS limit. Not only is compliance questionable at full load, but the results would indicate that load would need to be restricted to approximately 70% in order to have confidence in being able to meet the 0.030 lb/mmBtu standard. For Naughton Unit 3, a 30% derate is equivalent to a net reliable 99 MW restriction. It is anticipated that a permanent 30% load restriction when firing coal would need to be imposed on the unit in order to meet the MATS PM limit. Such a restriction would be enforced by limiting the hourly heat input or MW output of the unit. Validation of compliance with the PM rate and the established load restriction would be done by conducting quarterly PM tests.

Another option that should be considered is the use of continuous PM monitoring on Naughton Unit 3 to allow operating flexibility. The state of Wyoming has required the use of a continuous PM monitor on Naughton Unit 3 as a condition of the baghouse permit. If the installation of the PM CEMS was completed, such a system would allow the unit to be derated based on actual PM performance, and theoretically, would increase the ability to operate with fewer unit derates. The continuous PM monitor would be more expensive than quarterly testing, but could pay for itself with increased MW production compared to a fixed 30% derate. It is equally possible that continuous emission information could result in greater derates than the 30% estimates. Industry utilization of PM monitors is limited, and as such, reliability and accuracy of the monitors is somewhat unknown and will likely result in an operational learning curve both by the Company and the WDEQ.

If stand-alone non-mercury metals MATS compliance (PM surrogate) for Naughton Unit 3 emissions is pursued, it is recommended that normal ESP maintenance be conducted during any scheduled overhaul as required to maximize the PM emission reduction capabilities of the existing ESP. It is not recommended that significant capital be invested in the ESP to maximize the performance due to the short period of additional coal fueled operation anticipated.

Acid Gases

The testing conducted in March 2012 demonstrates that acid gases can be complied with through HCl testing even if controlling SO_2 emissions to 0.20 lb/mmBtu is difficult. No incremental cost to current operation is anticipated since the Unit 3 fuel coal sulfur content is expected to drop from 2012 levels by 2015.

With the new FGD installation on Naughton Units 1 and 2, the fuel supply will no longer be segregated between the units based on coal sulfur content. All coal comes from the same mine and other coal quality issues do not vary significantly between coal seams other than coal sulfur. It is not expected that homogenizing the coal supply to all three units will affect the ability of the units to meet the new MATS standards or increase the desirability to average the units together for MATS compliance.

Conclusions on Extending Coal Operation and Meeting MATS

If continued coal operation of Naughton Unit 3 is allowed through 2017, the following additional operating issues for each of the MATS pollutants must be addressed:

- Mercury - installation of coal oxidizer and FGD additive. Temporary injections systems for reagents would be used.
- Non-mercury metals - derate Naughton Unit 3 by approximately 99 MW (approximately 30%). Compliance with the 0.030 lb/mmBtu PM emission rate will be demonstrated with a new continuous PM monitor. Normal ESP maintenance would be conducted during a normal 2014 overhaul to prepare the unit for an additional 3-year run on coal. Alternatively, agree to an

operating limit of 231 MW net reliable output, a gross output limit commensurate with that derate, or a heat input limit and use quarterly PM testing to demonstrate compliance.

- Acid gases - quarterly HCl testing for MATS compliance (combined with SO_2 removal in the 0.20 lb/mmBtu range but not relied on for MATS compliance). No incremental cost to current operation since coal sulfur to Unit 3 is expected to drop by 2015.

CO_2

In its original economic analysis used to support the CPCN application, the Company analyzed low and high CO_2 market price scenarios around the Company's June 2011 official forward price curve ("OFPC") base alternative. The low market price scenario paired a low natural gas price forecast with a zero CO_2 price assumption, and the high market price scenario paired a high natural gas price forecast with a CO_2 price assumption of $25 per ton starting in 2015 and escalating at five percent plus inflation.

In the Company's updated rebuttal economic analysis of the SCR and baghouse investments at Naughton Unit 3, the scenario analysis was broadened to cover six different combinations of natural gas and CO_2 price assumptions as variations to the assumptions used in the updated base case alternative. Table NT3-7-1 below summarizes the directional changes to base case assumption among the six scenarios, with the scenario description indicating CO_2 price assumption for the first year that CO_2 prices are assumed. Two scenarios assume low and high natural gas prices with base case CO_2 assumptions held constant;

two scenarios assume low and high CO_2 price assumptions with the underlying base case natural gas prices held constant; and two scenarios pair different combinations of natural gas price and CO_2 price assumptions to serve as bookends around the base case. In any scenario when the CO_2 assumption varies from those used in the base case, the underlying natural gas price assumption is adjusted to account for any natural gas price response from changes in the electric sector natural gas demand.

Table NT3-7-1: Natural Gas and CO_2 Price Scenarios

Description	Natural Gas Prices	CO_2 Prices
Base Case	December 2011OFPC	$16 per ton in 2021, escalating at 3% plus inflation
Low Gas, $16 CO_2	Low	$16 per ton in 2021, escalating at 3% plus inflation
High, Gas, $16 CO_2	High	$16 per ton in 2021, escalating at 3% plus inflation
Base Gas, $0 CO_2	Base Case Adjusted for Price Response	No CO_2 Costs
Base Gas, $34 CO_2	Base Case Adjusted for Price Response	$34 per ton in 2018, escalating at 5% plus inflation
Low Gas, $34 CO_2	Low Case Adjusted for Price Response	$34 per ton in 2018, escalating at 5% plus inflation
High Gas, $0 CO_2	High Case Adjusted for Price Response	No CO_2 Costs

The Company assumed a zero CO_2 price for the low scenario recognizing that there had been limited activity in the CO_2 policy arena at the time of the updated rebuttal analysis. For the high CO_2 price scenario, prices were assumed to remain consistent with the upper limit that would have been established under the American Power Act of 2010 with an assumed start date in 2018. The high CO_2 price scenario start date aligns with the earliest start date assumed by the third party price forecasts reviewed by the Company. Figure NT3-7-1 below shows the three CO_2 price assumptions used in the market price scenarios in the updated analysis of SCR and baghouse investments at Naughton Unit 3.

<u>Emissions Performance Standards</u>

An additional constraint on operation of the unit natural gas conversion will involve complying with greenhouse gas Emissions Performance Standards ("EPS"), particularly those required by the state of Washington. Under regulations applicable to a Naughton Unit 3 gas conversion, in order to service the Company load in the state of Washington, if the converted unit is defined as a base load resource, it will need to emit less than 1,100 lbs. of CO_2 per net megawatt-hour ("MWh"). As shown in Table NT3-8-1, the use of natural gas in the existing Naughton Unit 3 boiler will result in CO_2 emissions above this standard. For this reason, the annual capacity factor will be required to be less than 60% in order for Naughton Unit 3 to be defined as a peaking resource in the state of Washington.

Table NT3-8-1: Naughton Unit 3 Natural Gas Conversion Assumpitons

Fuel Alternative	Gross Generation Capacity (MWg)	Auxiliary Power Consumption (MW)	Net Reliable Generation Capacity (MWn)	Full Load Net Plant Heat Rate (Btu/kWh)	Full Load CO_2 Production (lb/MWh)
Current Naughton Unit 3 on Coal	354	24	330	10,342	2,120
Naughton Unit 3 after natural gas conversion	354	16	338	10,859	1,281

On March 27, 2012, the EPA proposed new emission regulations for CO_2. These regulations are specific to *new* generation facilities and do not impose new standards for existing units or for proposed modification or reconstructions of existing units. Natural gas fuel conversion projects are not specifically addressed, while simple cycle gas turbines are addressed but excluded from the proposed rule, because these units are not base load machines. While "modifications" to existing units are specifically excluded, there is a risk that on a case-by-case basis the conversion of a facility could trigger the new standard or the standard could be broadened in the future. The exclusion of simple cycle machines though is a sign that converting Naughton Unit 3 to natural gas and to operate as a peaking unit would not be viewed to fall under the regulation. The new CO_2 emission regulation under the proposed rule for new generation is 1,000 lbs of CO_2 per net MWh generation. A refueled Naughton Unit 3 could not meet this standard, as shown in Table NT3-8-1.

Coal Combustion Residuals

While the Company will be faced with certain CCR storage, handling, and long-term management costs at its Naughton plant whether individual units at the plant continue to operate with coal as the fuel supply or not, natural gas conversion of Naughton Unit 3 would effectively eliminate the production of CCR from that unit. With elimination of the Unit 3 CCR waste steam, the Company would be obligated to begin closure of CCR infrastructure dedicated to Naughton Unit 3 and no longer in service. These CCR closure costs would be accounted for as an Asset Retirement Obligation ("ARO") expense.

Clean Water Act § 316(b)

Due to the preliminary status of the 316(b) rulemaking process, the Company has not completed specific detailed studies to fully ascertain and verify that intake structure retrofits or new technologies will be necessary to comply with the currently proposed 316(b) water intake regulations, particularly since a key element of the proposed rule is to conduct plant-specific studies and assessments. The Naughton plant utilizes cooling towers and closed-cycle cooling, significantly reducing potential 316(b) rulemaking exposure. Nonetheless, modifications may be needed at the Naughton raw water intake structure, located at the Hams Fork River diversion located north of the town of Frontier, Wyoming, to comply with the proposed impingement mortality standards. Since the raw water intake structure is a common system serving all units at the site, conversion of Naughton Unit 3 to natural gas is not expected provide material benefit to any such compliance costs.

Effluent Limitation Guidelines

The EPA proposed effluent limit guidelines for wastewater discharges from steam electric plants in April 2013, with final action currently expected by May 2014. Regardless of the EPA's final action, Naughton plant effluent is primarily managed as a common system serving all units at the site. As such, conversion of Naughton Unit 3 to natural gas may have only nominal benefit to any such compliance costs.

Rocky Mountain Power
Exhibit RMP___(CAT-8)
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Chad A. Teply

DEQ Letter dated March 6, 2013

January 2014

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Matthew H. Mead, Governor **Todd Parfitt, Director**

March 6, 2013

Ms. Cathy S. Woollums
Sr. Vice President, Environmental and
Chief Environmental Counsel
MidAmerican Energy Holdings Company
106 E. Second Street
Davenport, IA 52801

RE: Jim Bridger Units 3 & 4 SCR Controls

Dear Ms. Woollums:

Thank you for your letter, dated March 5, 2013, regarding your concerns about Wyoming's Regional Haze SIP and the November 2010 Settlement Agreement for Jim Bridger Units 3 and 4. In short your concern focuses on the deadline to install selective catalytic reduction (SCR) on these Jim Bridger units.

To start with, DEQ –AQD has stated previously that the terms and conditions of the Wyoming Regional Haze SIP are requirements that PacifiCorp still needs to meet. Under the Wyoming Regional Haze SIP that the State of Wyoming submitted to the EPA in January 2011, PacifiCorp is required to:

> (i) install SCR; (ii) install alternative add-on NOx control systems; or (iii) otherwise reduce NOx emissions to achieve a 0.07 lb/MMBtu 30-day rolling average NOx emissions rate. These installations shall occur, and/or this emission rate will be achieved on Unit 3 prior to December 31, 2015 and Unit 4 prior to December 31, 2016.

See Wyoming State Implementation Plan, Regional Haze, Addressing Regional Haze Requirements for Wyoming mandatory Federal Class I Areas Under 40 CFR 51.309(g), § 8.3.3 Long-Term Control Strategies for BART Facilities (January 7, 2011). Therefore, a change at this time to these requirements would entail a revision to our overall SIP with the EPA. This is one step that the DEQ-AQD does not intend to undertake at this time.

Secondly, you have requested that DEQ reconsider extending the Settlement Agreement deadlines for Jim Bridger Units 3 and 4. Under the Settlement Agreement, PacifiCorp must:

> (i) Install SCR; (ii) install alternative add-on NOx control systems; or (iii) otherwise reduce NOx emissions to achieve a 0.07 lb/mmBtu 30-day rolling average NOx emissions rate. These installations shall occur, and/or this emission rate will be achieved, on Unit 3 prior to December 31, 2015 and Unit 4 prior to December 31, 2016.

See In re: Appeal and Petition for Review of BART Permit No. MD-6040 (Jim Bridger Power Plant); and BART Permit No. MD-6042 (Naughton Power Plant), EQC Docket No. 10-2801, BART Appeal Settlement Agreement, ¶ 4(c) (filed Nov. 9, 2010). The Settlement Agreement may be modified if future changes in: "(i) federal or state requirements or (ii) technology would materially alter the emissions controls and rates that otherwise are required hereunder." *Id.* at ¶ 7. At this time, DEQ-AQD is unaware of any change in federal or state requirements, or technology, that would materially alter the required emissions controls or rates for Jim Bridger Units 3 and 4. Therefore, the DEQ-AQD continues to stand by its January 4, 2013 decision declining to extend the Settlement Agreement deadlines applicable to Jim Bridger Units 3 and 4.

If you would like more information or have additional questions, please contact me by phone at 307-777-7391. We appreciate your continued interest in Wyoming's environment.

Sincerely,

Steven A. Dietrich

Steven A. Dietrich, P.E.
Administrator, AQD

cc: Todd Parfitt, Director
Nancy Vehr, AG Office

Rocky Mountain Power
Exhibit RMP___(CAT-9)
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Direct Testimony of Chad A. Teply

Natural Gas Conversion Permits

January 2014

Natural Gas Conversion Permits

The Company intends to convert Naughton Unit 3 to 100% natural gas fueling in lieu of installing a SCR and baghouse. Before doing so, however, the state of Wyoming must change its Regional Haze SIP and the associated documents to allow for the natural gas conversion. Also, once EPA issues its final action on the Naughton Unit 3 portion of the Regional Haze SIP, EPA may need to reopen that approval and instead agree that the Naughton Unit 3 natural gas conversion meets regional haze requirements.

In the abstract, changing the Wyoming Regional Haze SIP, the supporting state permitting documents, and EPA's approval to allow for a gas conversion should not pose major permitting problems. This is because, as compared to burning coal with the SCR and baghouse alternative, the natural gas conversion will result in both lower total emissions (for sulfur dioxide ("SO_2"), NOx, particulate matter ("PM")) and reduced visibility impact.

The Company's preferred timing for the conversion is to proceed with the tie-in work after December 31, 2017 - three years after the December 31, 2014 deadline for installing a SCR and baghouse. The exact conversion commissioning date, however, has not yet been finalized.

On January 28, 2013, the Company submitted a Prevention of Significant Deterioration ("PSD") applicability determination to the WDEQ AQD. The Company sought approval to convert Naughton Unit 3 from a coal fueled unit to a natural gas fueled unit. The natural gas conversion is proposed as a better-than-BART alternative to the permit conditions that require the installation of a SCR and baghouse on Naughton Unit 3 by December 31, 2014. The Company also requested that the natural gas conversion be delayed until after December 31, 2017.

On July 5, 2013, the WDEQ AQD completed its final review of the Company's application to modify the Naughton plant by reducing permitted emissions from Unit 3 and ultimately converting the unit from a coal fueled unit to a 100% natural gas fueled unit in 2018. Consequently, the WDEQ AQD issued Permit MD-14506 to the Company for the natural gas conversion in 2018.

Exhibit CAT - 6 illustrates the permitting and regulatory timeline.