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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of: **THE VOLUNTARY REQUEST OF ROCKY MOUNTAIN POWER FOR APPROVAL OF RESOURCE DECISION TO CONSTRUCT SELECTIVE CATALYTIC REDUCTION SYSTEMS ON JIM BRIDGER UNITS 3 AND 4**	Docket No. 12-035-92 **ROCKY MOUNTAIN POWER'S VOLUNTARY REQUEST FOR APPROVAL OF RESOURCE DECISION TO CONSTRUCT SELECTIVE CATALYTIC REDUCTION SYSTEMS ON JIM BRIDGER UNITS 3 AND 4**

INTRODUCTION

Pursuant to Utah Code Ann. § 54-17-402, PacifiCorp dba Rocky Mountain Power (sometimes also referred to as the "Company") submits this *Voluntary Request for Approval of Resource Decision* (the "Request") to the Utah Public Service Commission (the "Commission"). The Company respectfully requests that the Commission issue an order approving the construction of a major emissions reduction project: the addition of selective catalytic reduction ("SCR") systems on Unit 3 and on Unit 4 of the Jim Bridger steam electric plant (the "Bridger SCR Project") located in Sweetwater County, Wyoming (the "Bridger Plant" or the "Plant").[1] The basis for seeking this Commission's approval is three-fold:

First, Bridger Units 3 and 4 are critical components of the Company's generation fleet that serves Utah customers. For the Company to provide adequate, safe, efficient and reliable service to Utah customers, the baseload capacity and energy provided by the units cannot be eliminated from the system without substituting a similar amount of baseload capacity and energy.

Second, pursuant to Wyoming environmental requirements and proposed EPA action on those requirements, ***Unit 3 cannot continue to operate beyond December 31, 2015, and Unit 4 cannot continue to operate beyond December 31, 2016 in their current operating modes and conditions. Compliance is not an option; only the means of compliance are options***.

Third, extensive analysis indicates construction of the Project and the continued operation of the units using coal is the least-cost compliance alternative (adjusted for risk and uncertainty) under a reasonable range of market conditions that have been evaluated.

Given the cost of the Bridger SCR Project necessary to comply with environmental requirements and the likelihood of differing opinions regarding the least-cost-adjusted-for-risk option in the face of regulatory uncertainty (both environmental and economic regulation), the Company believes that Commission review and approval in advance of construction is the best approach to permitting meaningful public and regulatory input.

[1] Rocky Mountain Power has previously filed a request for a Certificate of Public Convenience and Necessity with the Wyoming Public Service Commission.

Emission-reduction projects such as the Bridger SCR Project are complicated, time consuming, and must be coordinated with other projects to ensure that service is not compromised. Unless the Bridger SCR Project is completed on time, the Company risks noncompliance with required environmental regulations.

This Request is supported by the pre-filed testimony of Chad A. Teply, Vice President of Resource Development and Construction (the "Teply Direct" testimony), the pre-filed testimony of Rick T. Link, Director, Structuring & Pricing (the "Link Direct" testimony), and the materials provided below. Attachment "A" hereto is a matrix of additional information to be provided pursuant to Utah Admin Code R746-440-1(1).

BACKGROUND

Description of the Bridger Plant and the Associated Facilities

1. Rocky Mountain Power is a dba of PacifiCorp and is a public utility in the state of Utah subject to the jurisdiction of this Commission with regard to its public utility operations, retail rates, service and accounting practices. It provides retail electricity service in Utah, Wyoming and Idaho. PacifiCorp also provides retail electric service under the name of Pacific Power in the states of Oregon, Washington and California.

2. The Bridger Plant consists of four coal-fueled units which are two-thirds co-owned by Rocky Mountain Power and one-third co-owned by the Idaho Power Company. The Plant is maintained and operated by PacifiCorp Energy. Unit 3 began commercial operation in 1976 and Unit 4 followed in 1979. (Teply Direct at 10-11.)

3. The Plant has been, and remains, integral to the Company's charge of providing electrical service to its customers, not only in Wyoming, but also in Utah and the other states served by the Company. The Jim Bridger substation is contiguous to the Bridger Plant and

connects six major transmission lines: Populus #1 at 345 kilovolts ("kV"); Populus #2 at 345 kV; Threemile Knoll at 345 kV; Rock Springs at 230 kV; Point of Rocks at 230 kV; and Mustang at 230 kV. Bridger is dispatched on a system wide basis to serve PacifiCorp customers, including Utah customers. (Teply Direct at 11.)

4. The currently approved depreciable life, for Utah ratemaking purposes, for both Units 3 and 4 is through 2037. (Teply Direct at 17.)

5. The Bridger Plant is also directly adjacent to Rocky Mountain Power's and Idaho Power's co-owned Jim Bridger mine, which supplies approximately 6 million tons per year of sub-bituminous coal to the Plant. (Teply Direct at 12.)

6. The Plant currently employs approximately 327 personnel, including approximately 262 union craft personnel represented by the Utility Workers Union of America Local 127. (Teply Direct at 12.)

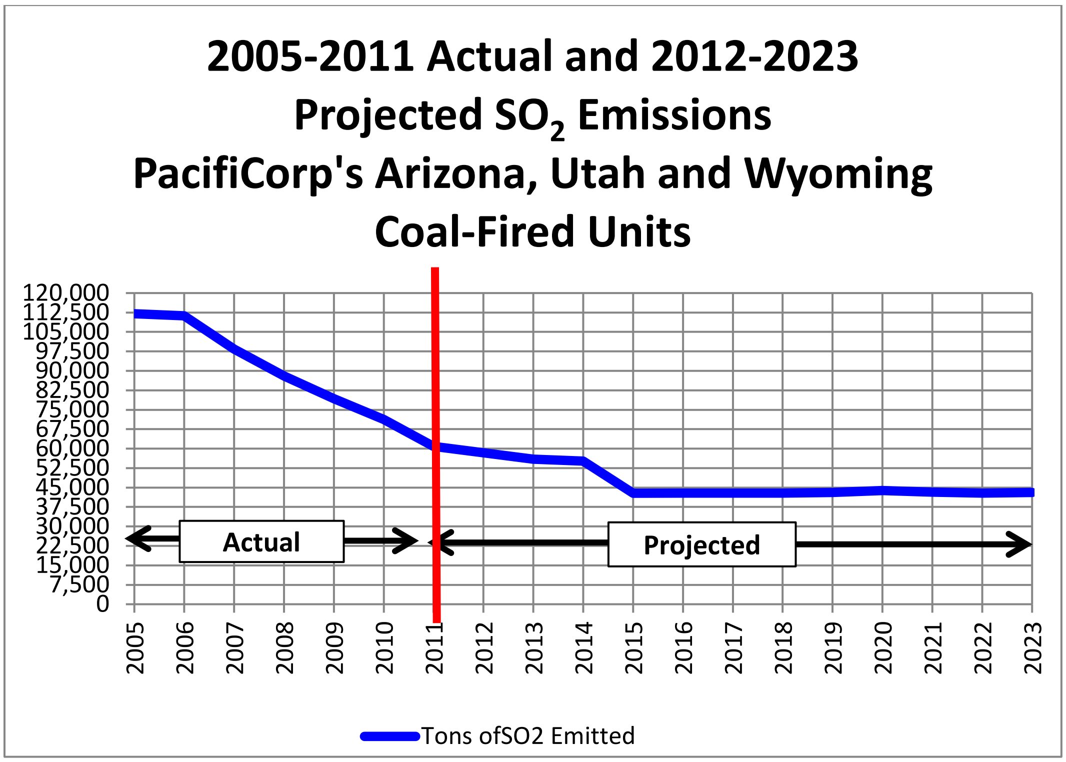
The Company's Emissions Control Plan

7. The emissions control investments included in the Company's long-term emissions control plan primarily result in the reduction of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), mercury ("Hg"), and particulate matter ("PM") emissions from generation facilities subject to federal and state emissions requirements. (Teply Direct at 12.) The Company's emissions control plan has been developed and maintained to ensure compliance with environmental regulations governing the Company's operations. Exhibits RMP___(CAT-4.1 through CAT-4.4) attached to Mr. Teply's testimony provide a forward-looking overview of the

projects currently included in the Company's emissions control plan and other environmental compliance plans, including current status and key regulatory drivers. (*Id*. at 32.)[2]

8. The following figures represent the reductions in SO_2 and NOx emissions that are expected to occur at units owned by the Company in Wyoming, Utah, and Arizona as a result of the Company's emissions control plan, including the Bridger SCR Project.

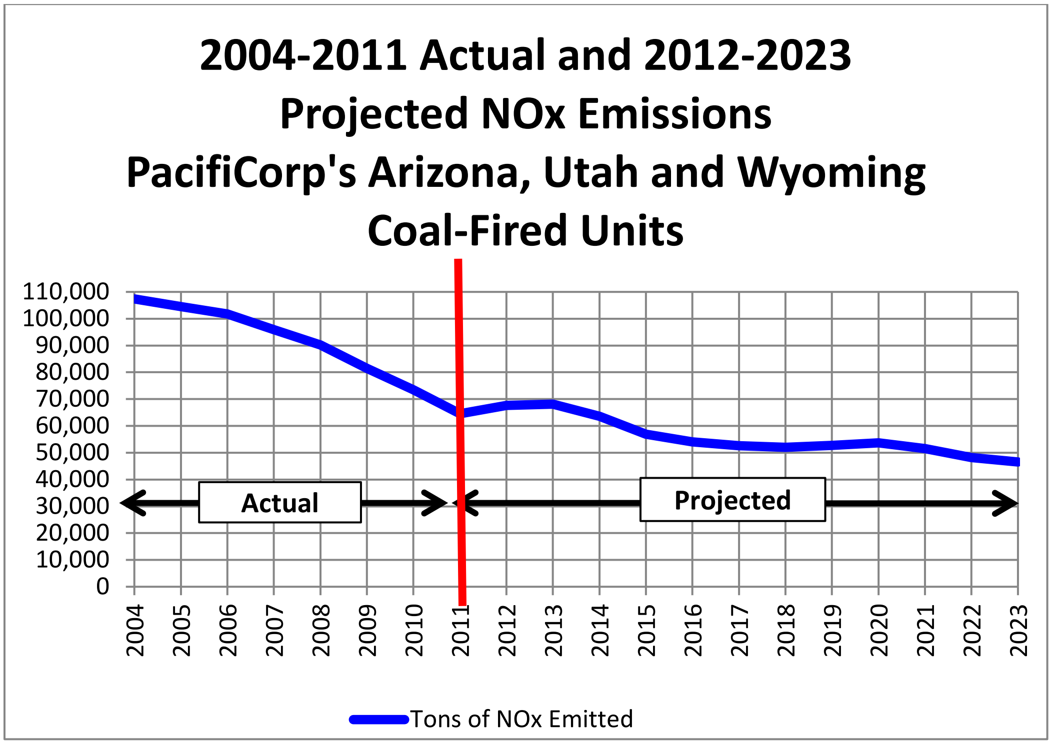
Figure 1



(Teply Direct at 35.)

[2] The Company's environmental projects are required to comply with existing Regional Haze Rules, Regional SO_2 Milestone and Backstop Trading Programs, National Ambient Air Quality Standards, and New Source Review requirements. The projects are also required to comply with stand-alone requirements in state SIPs, BART permits, construction permits, and approval orders enforceable by the laws of the respective states. The projects completed to date and/or currently permitted also position the Company well to comply with the EPA's recently finalized "MATS" standards. (Teply Direct at 13.)

Figure 2



(Teply Direct at 36.)

__The Need for the Emissions Control Project at the Bridger Plant__

9. As with Rocky Mountain Power's other plants, the Bridger Plant is subject to a variety of laws, rules, and regulations relating to SO_2, NO_X, Hg, and PM emissions from generation facilities, including "Regional Haze Rules" (discussed further below).

10. Pursuant to the Regional Haze Rules, Wyoming has imposed environmental standards under which the SCR systems are required to be installed at Bridger Units 3 and 4 for those Units to be able to continue to operate beyond 2015 and 2016 respectively. (Teply Direct at 13-14.)

11. Specifically, the Company's "Best Available Retrofit Technology" permit for the Bridger facility issued by Wyoming's Department of Environmental Quality on December 31, 2009 (the "BART" Permit) required the Company to submit permit applications for the

installation of SCR on Jim Bridger Units 3 and 4 by 2015 and 2016, respectively, under the state of Wyoming's Regional Haze Long-Term Strategy. The Company appealed these requirements; ultimately reaching a settlement agreement with the Wyoming Department of Environmental Quality, Air Quality Division in November 2010 (the "BART Settlement Agreement") ***which requires the Company to install SCR or alternative add-on NOx control systems on Unit 3 by the end of 2015 and on Unit 4 by the end of 2016*** to achieve required NOx emission limits. The Wyoming Regional Haze 309(g) State Implementation Plan (the "Wyoming SIP") issued on January 7, 2011, ***also includes these requirements***. The Company has filed its construction permit applications with the Wyoming Department of Environmental Quality ("WDEQ") reflecting these requirements. (Teply Direct at 13-14.)

12. In addition, the U.S. Environmental Protection Agency ("EPA") has proposed to approve the Wyoming SIP requirements as they pertain to the timing of SCR installation on Jim Bridger Units 3 and 4. Final action by the EPA is expected by mid-October 2012. The EPA's expected final approval would make these emission reduction requirements at Jim Bridger Units 3 and 4 federally enforceable as well. (Teply Direct at 14-15.)

13. Implementing the Bridger SCR Project will reduce the emission output of Bridger Units 3 and 4, and to allow the continued operation of Units 3 and 4 in compliance with the applicable environmental requirements.

<u>The SCR Systems to Be Installed and the Company's RFP</u>

14. The Bridger SCR Project is comprised of two universal reactors for each unit, with multiple catalyst levels; inlet and outlet ductwork; a shared ammonia reagent system; an economizer upgrade; structural reinforcement of the boiler and flue gas path ductwork and equipment; and extension of the existing plant distributed control system. An induced draft fan

upgrade and an associated auxiliary power system variable frequency drive insertion are required on Unit 4 only. (*See* Teply Direct at 13; *id*. at Confidential Exhibit RMP___(CAT-1) (providing details of the SCR system).)

15. Given the time-sensitive nature of commencing and completing the Project, the Company has already begun the competitive procurement process for engineer, procure and construction ("EPC") contract. In February 2012, the Company sent out requests for proposals ("RFPs") to approximately 26 potential technology providers, engineers and contractors that were prequalified as being capable of completing various components of the scope. In order to execute the full scope, it was generally necessary that the invited entities form teams to complete all aspects of the EPC contract scope. The EPC teams that formed generally include a technology provider, engineer and a constructor. (Teply Direct at 8-9.)

16. As part of the RFPs, the Company sent a template contract to the potential EPC contractors to use as a baseline in negotiations. A copy of the template contract is attached to the Teply Direct testimony as Confidential Exhibit RMP___(CAT-9). (Teply Direct at 8-9.)

17. The Company is currently evaluating the technical proposals received from five potential EPC contract teams, and anticipates that it will be able to finalize a contract with the least-cost evaluated supplier within 5 months from the date of this Request. (Teply Direct at 9.)

18. The Company's share of the estimated project cost for the Unit 3 SCR system is approximately [redacted]. (Confidential Exhibit RMP___(CAT-1.2 at 1.) The Company's share of estimated project cost for the Unit 4 SCR system is approximately [redacted]. (*Id*. at 3.)

19. A detailed description of the Company's cost analysis is provided at Confidential Exhibit RMP___(CAT-1) attached to the Teply Direct, and is set forth at Confidential Exhibit RMP___(CAT-1.2).

20. While the Company's current estimate of its total share of the cost to complete the Bridger SCR Project is [redacted], the actual cost will be determined by the final agreements and related project cost. Once an agreement for the EPC contract is finalized, the Company will submit it to the Commission as a supplement to this Request.

The Selected SCR Systems Are the Least-Cost Alternative

21. As discussed further below, the Company evaluated a number of compliance alternatives in addition to the installation of the SCR systems at the Bridger Plant. This analysis demonstrated that retrofitting the Units with the selected SCR systems to allow ongoing coal fueled energy production through the Plant's depreciable life is the least-cost, adjusted for risk, outcome for customers. (Teply Direct at 16.) Indeed, and as discussed further below, the Company's economic analyses show a [redacted] present value revenue requirement differential ("PVRR(d)") in favor of implementing the Bridger SCR Project as compared to next best option. (Link Direct at 14.)

Timing for the Project Is Critical

22. Timely Commission approval is critical in this matter. The Company seeks approval to implement the Bridger SCR Project because the Project must be complete to continue operating Unit 3 beyond 2015 and Unit 4 beyond 2016. To complete the Bridger SCR Project in the required timeframe, however, will require the Company to keep to a tight planning and implementation schedule. Indeed, the Company believes that Spring 2013 is the latest time in which it can commence the Project and meet its deadlines in the most economical manner. As

further discussed below, emission reduction projects of this size are extremely complex, and take many years to plan, permit, engineer, procure, construct, and commission. Moreover, there are numerous practical limitations. For example, there are limitations on available construction resources and labor, a limit on the number of generation resources that may be taken out of service at any given time, as well as a limit on the level of construction activities that can be supported by the local infrastructures at and around the facilities.

ARGUMENT

Under Utah law, the Commission has the authority to hear voluntary requests to approve proposed "resource decisions" by a utility outside of a general rate case. Utah Code Ann. § 54-17-402. These decisions include those relating to "an energy utility's acquisition, management, or operation of energy production, processing, transmission, or distribution facilities or processes." *Id.* § 54-17-401(2)(a).[3] When considering a voluntary request to approve a resource decision, the Commission must determine "whether the decision is in the public interest." *Id.* § 15-17-402(3)(b).[4]

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[3] A "resource decision" is defined as a decision (other than a decision to construct or acquire a significant energy resource) involving:

> (i) an energy utility's acquisition, management, or operation of energy production, processing, transmission, or distribution facilities or processes including:
>
> (A) a facility or process for the efficient, reliable, or safe provision of energy to retail customers; or
>
> (B) an energy efficiency and conservation program; or
>
> (ii) a decision determined by the commission to be appropriate for review under this part.

Utah Code Ann. § 54-17-401(2)(a)(i)-(ii).

[4] To determine "public interest," the Commission may consider:

> (i) whether it will most likely result in the acquisition, production, and delivery of utility services at the lowest reasonable cost to the retail customers of an energy utility located in this state;
>
> (ii) long-term and short-term impacts;
>
> (iii) risk;
>
> (iv) reliability;
>
> (v) financial impacts on the energy utility; and
>
> (vi) other factors determined by the commission to be relevant.

Utah Code Ann. § 15-17-402(3)(b).

In this case, the Company's decision to implement the Bridger SCR Project constitutes a "resource decision" that, pursuant to the Company's voluntary Request, this Commission should review. Indeed, given the significant cost involved in the Project, the uncertainty of future regulation of thermal generation emissions, and the likelihood of differing public opinion regarding the least-cost least-risk options, reviewing PacifiCorp's voluntary Request in advance of construction (and a rate case) will allow the Commission an opportunity to evaluate the Project contemporaneously with the decision while changes to the decision (if determined appropriate and necessary) can be economically undertaken.

Certainly, the Bridger SCR Project is in the public interest. As discussed below, the SCR systems must be installed for the Company to continue to operate Units 3 and 4 beyond 2015 and 2016 respectively in a manner that will satisfy its environmental obligations and with the least-cost outcome for customers.

I. The Bridger SCR Project Is in the Public's Best Interest.

A. The Project Is Required to Satisfy the Company's Environmental Obligations.

The Company plans to proceed with the Bridger SCR Project in order to comply with Wyoming's applicable Regional Haze Rules and the EPA's proposed approval of Wyoming's SIP requirements. (Teply Direct at 44.)

1. Regional Haze Rules

The primary driver of this Request is the Company's obligations under Regional Haze Rules. Through the 1977 amendments to the Clean Air Act, Congress set a national goal for visibility to remedy impairment from man-made emissions in designated national parks and wilderness areas. This goal resulted in development of the Regional Haze Rules, adopted in 2005 by the EPA. (Teply Direct at 18-19.)

The first phase of these Rules triggers "BART" reviews ("Best Available Retrofit Technology") for all coal-fired generation facilities built between 1962 and 1977 that emit at least 250 tons of visibility-impairing pollution per year. Visibility-impairing pollutants include SO_2, NO_x and PM. Pursuant to federal regulations, each state was required to determine which BART-eligible sources are also "subject to BART." BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to impairment of visibility in designated national parks or wilderness area. 40 CFR 51.308(e)(1)(ii). (Teply Direct at 18.)

The Bridger Plant is a BART-eligible source. Pursuant to the Regional Haze Rules, the investments in emissions control equipment at the Company's BART-eligible units, including Jim Bridger Units 3 and 4, have been determined by Wyoming state environmental regulators to be necessary, after having considered available technology, costs of compliance, energy and non-air quality environmental impacts, existing control equipment and the remaining useful life of the facility, and the degree of improvement in visibility reasonably anticipated to result from the use of such technology. (Teply Direct at 18-19.) Specifically, the BART Settlement Agreement and the Wyoming SIP require NOx emission limits of 0.07 pounds per million British thermal units ("lb/mmBtu) to be achieved on Unit 3 by the end of 2015 and on Unit 4 by the end of 2016 via the installation of SCR or alternative add-on NOx control systems; with SCR being the emissions control technology solution identified during the state's BART-determination process as producing the required results. The Company has filed its construction permit applications with the WDEQ reflecting these requirements. (Teply Direct at 14-15.)

2. The EPA's Proposed Approval of Wyoming's SIP Requirements.

In a notice published in the *Federal Register* on June 4, 2012 relating on Wyoming's SIP (as it relates to NO_x), the EPA has recommended approval of SCR and low NO_x burner installations on Jim Bridger Units 3 and 4 within the deadlines prescribed in Wyoming's SIP and associated permits. The EPA's proposed action on Wyoming's SIP (as it relates to SO_2) was to recommend approval of the SIP, which incorporates the established emissions limits assigned to the Bridger Units 3 and 4 scrubbers as currently configured. Final action by the EPA is expected by mid-October 2012, and EPA's expected final approval would make these emission reduction requirements at Jim Bridger Units 3 and 4 federally enforceable as well. (Teply Direct at 14-15.)[5]

3. Other Existing and Emerging Regulations

The Company also considered a number of other existing and emerging environmental regulations in its decision making process regarding the Bridger SCR Project. For example:

- ***MATS***. The final Mercury and Air Toxics Standards ("MATS") were published in the *Federal Register* on February 16, 2012, with an effective date of April 16, 2012, and require that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. While the Bridger SCR Project will

[5] Although the EPA action has not been finalized, deferring the Bridger SCR Project until its finalization or until the regulatory landscape is clearer is neither prudent nor practical. (Teply Direct at 44-53.) Rulemaking procedures are often lengthy, and many times are followed by extensive litigation. The lack of certainty in environmental regulation is well recognized, but does not obviate existing compliance obligations. Moreover, it is unlikely that the Bridger SCR Project will be rendered unnecessary in future rulemaking. Indeed, history demonstrates that regulations become more stringent over time. The controls included in the Company's emissions control plan are necessary to allow the Company to continue operating these facilities given that increasing stringency. Further, the Company's analysis suggests that these controls place the facilities in a position to continue to generate reasonably priced electricity under contemplated environmental regulations, even if greenhouse gas legislation is adopted. (Teply Direct at 50.) Finally, the Wyoming SIP and BART Settlement Agreement (and permits issued reflecting their requirements) constitute stand-alone requirements that are enforceable independent of whether EPA has approved the respective state implementation plans. (Teply Direct at 52.)

not directly control emissions required to support MATS compliance, the Units are otherwise positioned well to comply with the standards for acid gases and non-mercury metallic HAPS.[6] (Teply Direct at 7 & 22-23.)

- ***CCR Regulations***. The Company also considered proposed regulations regarding coal combustion residuals ("CCR"). In response to the proposed CCR rulemaking, the Company has updated its CCR-related costs and asset retirement obligations on a preliminary basis to incorporate proposed Subtitle D or near-Subtitle D infrastructure requirements, which will serve as a planning proxy for the Company until such time as the EPA responds to the completed public comment period for CCR regulations. The Company anticipates that compliance with final CCR rules promulgated as a result of the ongoing EPA effort will be required five years after final rulemaking, or by late-2017 at the earliest, based on the EPA's current intent. 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 analyses. The Company has also incorporated appropriate CCR design provisions and compliance planning into the technical specifications for the Jim Bridger Units 3 and 4 SCR systems. (Teply Direct at 23-25.)

- ***Proposed CWA Regulations***. Due to the preliminary status of the Clean Water Act 316(b) rulemaking process, the Company has not completed specific detailed studies to fully ascertain and verify that intake structure retrofits or new technologies are necessary to comply with the currently proposed 316(b) water intake regulations, particularly since a key

[6] The Company will be required to take additional actions to reduce mercury emissions through the installation of controls and use of reagent injection at Bridger Units 3 and 4 to otherwise comply with the final rule's standards. Budgeted costs for these additional actions have been incorporated into the financial analyses supporting this application. (Teply Direct at 7.)

element of the proposed rule is to conduct plant-specific studies and assessments. While the EPA was expected to issue a final rule by July 27, 2012, the issuance of the rule has now been deferred to June 2013. The Jim Bridger plant utilizes cooling towers and closed cycle cooling, significantly reducing potential 316(b) rulemaking exposure. Nonetheless, modifications may be needed at the Jim Bridger cooling water intake structure, located at the Green River diversion, to comply with the proposed impingement mortality standards. As such, the Company has developed a preliminary estimate of the costs associated with potential studies and potential mitigation projects at Jim Bridger by extrapolating results of a 2007 study completed at the Company's Dave Johnston facility prior to the suspension of the Phase II Section 316(b) rule. The currently estimated costs for the Jim Bridger facility have been incorporated into the analyses completed and are described in Confidential Exhibit RMP___(CAT-1) to Mr. Teply's testimony. (Teply Direct at 24-27.)

- ***CO_2 Cost Sensitivities.*** The Company evaluated CO_2 cost sensitivities and resulting market pricing assumptions in its System Optimizer modeling efforts in support of the Project. (Link Direct at 23-26.) As discussed further below, and in detail in the testimony of Mr. Link, this analysis concluded that levelized CO_2 prices over the period 2016-2030 would have to be in excess of $36 per ton, or 239 percent above the base case, to achieve a breakeven point for the Bridger SCR Project analyzed together. (Link Direct at 25.)

- ***Other Future Environmental Regulations.*** While the Bridger SCR Project requested for approval in this Request are driven by current environmental requirements, the Company has also considered the need for the incremental emission reductions and the type of controls that could be required in the future when planning for this project. There are a multitude of environmental requirements the electric industry faces over the next several years.

An EPA environmental regulations development timeline provided in Confidential Exhibit RMP___(CAT-4, Figure CAT-4.1) identifies some of the environmental requirements that are currently underway or in development. (Teply Direct at 28.)

For example, increasingly more stringent National Ambient Air Quality Standards have been and are being adopted for criteria pollutants, including SO_2, NO_2, ozone, and PM. Although Utah and Wyoming have not yet made any determinations as to what, if any areas may be in nonattainment with respect to the new standards, implementation of the Bridger SCR Project, as described in Confidential Exhibit RMP___ (CAT-1) to Mr. Teply's testimony, is expected to assist in meeting these more stringent standards. (Teply Direct at 28-29.)

- ***Wildlife Considerations***. Exhibit RMP___(CAT-2) attached to Mr. Teply's testimony specifically discusses potential impacts to plant and animal life in the areas surrounding the project. In general, because the project will be executed entirely within the plant-proper boundaries of the existing Jim Bridger facility, no material impacts in this regard are expected. (Teply Direct at 30.)

B. The Emission Control Project at the Bridger Plant Will Benefit Customers by Allowing the Company to Operate the Plant Most Cost Effectively.

The Company has thoroughly evaluated the Bridger SCR Project's economics, concluding that the Project is the least-cost, adjusted for risk, outcome for customers. (Teply Direct at 16.) Indeed, and as discussed below, the Company's economic analysis show a [redacted] PVRR(d) in favor of implementing the Bridger SCR Project at the coal-fired Units as compared to the next best option. (Link Direct at 14.)

1. Evaluation of Compliance Options

The Company's first analysis was a PVRR(d) analysis using the System Optimizer model ("SO Model").[7] The SO Model is capable of simultaneously and endogenously evaluating capacity and energy tradeoffs between making incremental investments required to meet emerging environmental regulations and a broad range of alternatives including fuel conversion, early retirement and replacement with greenfield resources, market purchases, demand side management resources, and/or renewable resources. In this way, the SO Model captures the cost implications of prospective investment decisions by evaluating net power cost impacts along with the impacts those decisions might have on future resource acquisition needs, which is particularly important when resource retirement and replacement is considered to be an investment alternative. (Link Direct at 3-4.)

In this instance, two SO Model simulations were completed – an optimized simulation and a change case simulation – for a range of market price scenarios.[8] In the optimized simulation, the SO Model determines whether continued operation of Jim Bridger Units 3 and 4 inclusive of incremental SCR and other planned costs required to achieve compliance with emerging environmental regulations is a lower cost solution than avoiding those incremental investments through early retirement and resource replacement or through conversion to natural gas. In the change case simulation, the SO Model is forced to produce a suboptimal decision by not allowing it to make the preferred decision that was made in the optimized simulation. The

[7] The SO Model is used in the Company's integrated resource plan and business planning process to produce resource portfolios in support of long-term planning. The SO Model is also used in the Company's analysis of resource acquisition opportunities and resource procurement activities. For example, the SO Model was used to support the successful acquisition of the Chehalis combined cycle plant, to support the selection of the Lake Side 2 combined cycle resource in the most recently completed request for proposals process, and is being used to evaluate bids in the currently issued request for proposals for a 2016 resource as approved by the Public Service Commission of Utah and Oregon Public Utility Commission. (Link Direct at 3.)

[8] Six different combinations of natural gas and CO_2 price assumptions were analyzed as variations to the base case. (Link Direct at 9-10.) These combinations are explained in Mr. Link's testimony.

differences in system costs, inclusive of differences in net power costs, operating costs and capital investment costs, between the two simulations for any given market price scenario represents the PVRR(d), which establishes how favorable or unfavorable the incremental environmental capital investments planned for Jim Bridger Units 3 and 4 are in relation to the next best alternative. (Link Direct at 4-5.)

In addition to brown field natural gas conversion of Jim Bridger Unit 3 and/or Jim Bridger Unit 4, the SO Model was configured with a range of resource replacement alternatives, including: (a) green field natural gas resources, (b) firm market purchases, (c) demand side management, and (d) and incremental wind resources. (Link Direct at 6.)

The results of this analysis overwhelmingly support the Company's decision to implement the SCR projects. The optimized base case simulation from the SO Model selected the SCR investment at both Units. Moreover, the three change case simulations – one in which Unit 3 was not allowed to select SCR, one in which Unit 4 was not allowed to select SCR, and one in which Units 3 *and* 4 were not allowed to select SCR – shows that gas conversion is the next best, albeit higher cost, alternative to the SCR investment. The PVRR(d) between the optimized simulation, as summarized in Confidential Exhibit RMP___(RTL-3), shows that the SCR option is:

- [redacted] more favorable than gas conversion for Jim Bridger Unit 3,
- [redacted] more favorable than gas conversion for Jim Bridger Unit 4, and
- [redacted] more favorable than gas conversion for Jim Bridger Units 3 *and* 4.

(Link Direct at 14.)

Indeed, levelized natural gas prices over the period 2016 through 2030 would need to decrease by 19 percent, from $6.18 per mmBtu to $4.99 per mmBtu, to achieve a *breakeven*

PVRR(d) for Jim Bridger Unit 3. For Unit 4, break even economics would require levelized gas prices to drop to $5.12 per mmBtu over the period 2016 to 2030, which is more than 17 percent below base case natural gas prices. When analyzed together, levelized gas prices would need to fall to $4.99 per mmBtu, or 19 percent below the base case, to achieve a breakeven PVRR(d). (Link Direct at 22).

Moreover, based upon the trends shown in the figures within Confidential Exhibit RMP___(RTL-7), levelized CO_2 prices over the period 2016 through 2030 would need to exceed $35 per ton, more than three times the base case nominal levelized CO_2 price assumption, to achieve a breakeven PVRR(d) for Jim Bridger Unit 3 SCR investment. Break even economics would require a levelized CO_2 price of $34 per ton over the period 2016 to 2030, which is 220 percent higher than base case CO_2 prices, for Jim Bridger Unit 4 SCR investment. When the SCR investments for both Jim Bridger Unit 3 and Unit 4 are analyzed together, nominal levelized CO_2 prices would need to be in excess of $36 per ton, or 239 percent above the base case, to achieve a breakeven PVRR(d). (Link Direct at 23-25.)

Based on the Company's overall analysis, the Commission should conclude that, approving the Company's resource decision to install the Bridger SCR Project and allow ongoing coal fueled energy production through the Plant's depreciable life is the least-cost, adjusted for risk, outcome for Utah customers.[9]

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[9] The Company performed a similar SO Model analysis of SCR and bag house investments required to continue operating Naughton Unit 3 as a coal-fueled facility. In contrast to the analysis for Jim Bridger Units 3 and 4, the base case analysis for Naughton Unit 3 produced a PVRR(d) that favored converting Naughton Unit 3 to a natural gas-fueled facility. (Link Direct at 14-19.) However, the economics of the Bridger Plant favoring the SCR systems are different, resulting in a different indicated approach to compliance. Specifically, the key drivers resulting in a different decision here are:

A. There is a significant difference in capital investment costs associated with the required emissions control retrofit projects for Jim Bridger Units 3 and 4. Significantly, the cost on a dollars per kilowatt basis is approximately *half* of that required for the Naughton Unit 3 retrofits because of the lack of baghouse requirements for Jim Bridger Units 3 and 4 and the larger generation capacity of the Jim Bridger units. That is, the SCR project is less costly per unit of production at Bridger.

2. Evaluation of Available Emissions Control Technologies.

As part of the BART review of each facility, the Company evaluated several technologies on their ability to economically achieve compliance and support an integrated approach to control criteria pollutants (*e.g.* SO_2, NO_X, and PM for the facility), if it were to continue to operate and to burn coal. The BART analyses reviewed available retrofit emission control technologies and their associated performance and cost metrics. Each of the technologies was reviewed against its ability to meet a presumptive BART emission limit based on technology and fuel characteristics. The BART analyses outlined the available emission control technologies, the cost for each, and the projected improvement in visibility which can be expected by the installation of the respective technology. (Teply Direct at 20-21.)

For each unit or source that is subject to BART, the state environmental regulatory agency identifies the appropriate control technology to achieve what the air quality regulators determine are cost-effective emission reductions. Wyoming's BART determination for Bridger Units 3 and 4, including the Bridger SCR Project as part of the state's Regional Haze Long Term Strategy, is discussed further in Confidential Exhibit RMP___(CAT-4) and was incorporated into the final requirements now reflected in the BART Settlement Agreement and the Wyoming SIP.[10] (Teply Direct at 21 & 13-14.) The Company has filed its construction permit applications with the WDEQ reflecting these requirements. (Teply Direct at 15.)

> B. There are also differences in levelized annual operating costs and run-rate capital costs between the individual units. The differences in ongoing costs between gas conversion and continued coal operation for Naughton Unit 3 as compared to Jim Bridger Units 3 and 4 are primarily driven by lower operational and maintenance costs at the Jim Bridger units when fueled by coal as compared to Naughton Unit 3.

(Teply Direct at 5-6.)

[10] Once the required technology and in-service timing requirements were identified, the Company moved forward with its permitting and competitive bidding processes to specify, evaluate and ultimately select the preferred provider for the projects. Evaluation and selection of the preferred provider for the projects has not yet been completed. (Teply Direct at 21.)

C. Utah Customers Will Benefit from the Project at the Bridger Plant.

Utah customers will directly benefit by the implementation of the emission control investments at the Bridger Plant. First, customers will benefit from the continued availability of cost-based generation produced at the facilities while also achieving environmental improvements from these resources. Again, ***Unit 3 cannot operate beyond December 31, 2015, and Unit 4 cannot operate beyond December 31, 2016 without the Project being complete.*** In addition, the tie-in of these controls is being accomplished during planned maintenance outages, as opposed to scheduling separate outages for this work, which reduces replacement power costs. The Company has 10 BART-eligible units in Wyoming and four in Utah. The BART controls for each of these units ***must*** be installed as expeditiously as possible, but no later than five years from the date the respective SIPs are approved and prior to the compliance dates specified in the respective permits.

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

Finally, maintaining the ability to operate the existing coal fueled units that have been or are planned to be retrofitted with economic emissions control equipment represents the least-cost option for customers, especially when considered in conjunction with the other generation resource addition projects that the Company has completed and intends to complete as part of its regularly updated IRP preferred portfolio implementation effort. This is even before considering factors associated with retirement of the coal units prior to the end of their ratemaking depreciation lives, such as stranded depreciation expense, the economic impact on the respective states in which the assets reside, and the potential impact on system reliability.

II. Timing for Approval and Commencement of the Project Is Critical.

The completion of large-scale emissions projects such as the Bridger SCR Project is not a quick process. To the contrary, these projects are extremely complex and require a significant amount of evaluation, planning, and permitting requirements, that often has a multi-year duration.

In this case, the Company is working under a well-defined end date. As explained above, the Bridger SCR Project must be completed for Bridger Units 3 by December 31, 2015 and for Unit 4 by December 31, 2016. The Company believes that Spring of 2013 is the latest date to commence the Project in order to effectively meet the required deadlines. Given this timeframe, the Company has worked diligently upfront to identify the various components of the project and to begin the procurement process. The Company is well into that process and anticipates that it will be able to finalize negotiations on an EPC contract by [redacted]. The Company has submitted as part of this Request a copy of the template EPC contract sent to potential contractors, and will submit a final contract to the Commission as a supplement to this Request once it is complete.

Simultaneously with its procurement activities, the Company has filed this Request to initiate the voluntary approval process. It has done so to help ensure that the process is complete by the time construction must commence. The Utah statute governing the voluntary approval process initially provides for a 180-day approval period. Utah Code Ann. § 54-17-402(6). This 180-day period should provide ample time for the Commission and other parties to evaluate the Company's Request, and for the Company to finalize contract negotiations.

Commission approval within the next six months is critical for a variety of logistical and practical reasons. For example, the approval process will be complete before construction commences, which will allow the Company to potentially make modifications to the Project (if determined appropriate and necessary through this approval process) more economically. Moreover, given the Project's size and complication, and the reality of the multistate operations and planning process for a utility the size of Rocky Mountain Power, delayed approval increases the risk of missing the compliance window and running up costs. There is a limit on the number of units that may be taken out of service at any given time. And given a fleet the size of the Company's, there is a practical limitation on available construction resources and labor. There is also a limit on the level of construction activities that can be supported by the local infrastructures at and around these facilities. Additional cost and construction-timing limitations include the loss of large generating resources during some parts of construction and the associated impact on the reliability of the Company's electrical system during these extended outages. In light of these considerations, the Company believes that completing this voluntarily request process within the next six months will help the Company initiate the Project in the most practical and economical manner.

REQUEST FOR RELIEF

1. That the Commission notice a scheduling conference to set a schedule for interested persons to file comments and reply comments on the request for approval of the energy resource decision to implement the Bridger SCR Project, for any technical conferences

deemed useful to the Commission or interested parties, for a hearing on this Request and for other processes and procedures deemed reasonable or necessary by the Commission in determining to approve this Request.

2. That the Commission issue an order pursuant to Utah Code Ann. § 54-17-402 approving the construction of the Bridger SCR Project. Rocky Mountain Power is currently evaluating bids, and will authorize construction as soon as the Commission grants the approval and all other critical permitting requirements are met.

COMMUNICATIONS AND DISCOVERY

Communications regarding this application should be addressed to:

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In addition, Rocky Mountain Power requests that all data requests regarding this application be sent in Microsoft® Word or plain text format addressed to:

By email (preferred): datarequest@pacificorp.com

Or by regular mail to: Data Request Response Center
Rocky Mountain Power
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries related to this application may be directed to David L. Taylor at telephone number (801) 220-2923.

DATED this 24th day of August, 2012.

Respectfully submitted,

____

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ATTACHMENT A

R746-440-1(1)(a)-(k) Information Location Matrix

Paragraph	Filing Requirement	Testimony and Exhibits
(a)	A description of the Resource decision	1. Teply testimony 2. Confidential Exhibit RMP___(CAT-1)
(b)	Information to demonstrate that the Energy utility has complied with the applicable requirements of the Act and Commission rules	1. *Prefiling Notice of Intent to File a Voluntary Request for Approval of Significant Energy Resource Decision*, filed 8/10/12. 2. Link testimony 3. Teply testimony
(c)	The purposes and reasons for the Resource decision	Teply testimony
(d)	An analysis of the estimated or projected costs of the Resource decision, including the engineering studies, data, information and models used in the Energy utility's analysis	1. Confidential Exhibit RMP___(CAT-1.2) (Initial Capital Cost Estimates) 2. Confidential Exhibit RMP___(CAT-1.3) (Incremental Operational and Maintenance and Ongoing Capital Costs)
(e)	Descriptions and comparisons of other resources or alternatives evaluated or considered by the Energy utility, in lieu of the proposed Resource decision	1. Link testimony 2. Teply testimony 3. Confidential Exhibit RMP___(CAT-4)
(f)	Sufficient data, information, spreadsheets, and models to permit an analysis and verification of the conclusions reached and models used by the Energy utility	Link testimony
(g)	An analysis of the estimated effect of the Resource decision on the Energy utility's revenue requirement	Link testimony and Confidential Exhibit RMP___(RTL-3)
(h)	Financial information demonstrating adequate financial capability to implement the Resource decision	Confidential Exhibit RMP___(CAT-1)
(i)	Major contracts, if any, proposed for execution or use in connection with the Resource decision	Confidential Exhibit RMP___(CAT-8)
(j)	Information to show that the Energy utility has or will obtain any required authorization from the appropriate governmental bodies for the Resource decision	1. Exhibit RMP___(CAT-2) 2. Exhibit RMP___(CAT-2.3) (Permits)
(k)	Other information as the Commission may require	No other information has currently been requested.