Rocky Mountain Power
Docket No. 17-035-40
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Supplemental Direct and Rebuttal Testimony of Joelle R. Steward

January 2018

Q. Please state your name, business address, and current position with Rocky Mountain Power ("Company"), a division of PacifiCorp.

A. My name is Joelle R. Steward. My business address is 1407 West North Temple, Suite 330, Salt Lake City, Utah 84116. My title is Vice President of Regulation for Rocky Mountain Power.

QUALIFICATIONS

Q. Please describe your education and professional background.

A. I have a Bachelor of Arts degree in Political Science from the University of Oregon and a Masters of Public Affairs from the Hubert Humphrey Institute of Public Policy at the University of Minnesota. Between 1999 and March 2007, I was employed as a Regulatory Analyst with the Washington Utilities and Transportation Commission. I joined the Company in March 2007 as the Regulatory Manager responsible for all regulatory filings and proceedings in Oregon. From February 2012 through May 2016, I was a Director in charge of the work for the cost of service, pricing, and regulatory operations groups for the Company. In 2016, I became the Director of Rates and Regulatory Affairs and added responsibilities for regulatory affairs for Rocky Mountain Power. In November 2017, I assumed my current position as Vice President of Regulation for Rocky Mountain Power.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the public utility commissions in Idaho, Oregon, Utah, Wyoming, and Washington.

Q. Are you adopting the direct testimony of Mr. Jeffrey K. Larsen in this case?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your supplemental direct and rebuttal testimony?

A. My testimony supports the Company's request that the Public Service Commission of Utah ("Commission") approve its significant energy resource decision for new wind resources ("Wind Projects") and voluntary energy resource decision for construction of the Aeolus-to-Bridger/Anticline line and network upgrades("Transmission Projects"), as reflected in this supplemental filing (collectively, the "Combined Projects"). In my supplemental direct testimony, I update the expected costs and benefits proposed to be recovered through the Resource Tracking Mechanism ("RTM"), associated with the Combined Projects based on the Company's 2017R Request for Proposals ("2017R RFP") final shortlist.

In my rebuttal testimony, I respond to regulatory policy and ratemaking issues raised in the direct testimonies of Division of Public Utilities ("DPU") witnesses Dr. Joni Zenger, Mr. Daniel Peaco, and Mr. David Thomson; Utah Association of Energy Users ("UAE") and Utah Industrial Electricity Consumers ("UIEC") witness Mr. Bradley Mullins; and Office of Consumer Services ("OCS") witnesses Mr. Bela Vastag and Ms. Donna Ramas.

Q. What are the key issues you address in your rebuttal testimony?

A. I address the following key issues:

- The reasonableness of allowing full recovery of the prudent costs of the Combined Projects, including a return on investment.
- How the Company's proposed RTM fairly and efficiently allows costs and benefits to be tracked through rates on a temporary basis until the next general

rate case.

Q. Please summarize your testimony.

A. The lower rate impact of the Combined Projects reflects the reduction in costs and increase in benefits in the Company's updated economic analysis provided by Company witness Mr. Rick T. Link. It also reflects the effects of federal tax reform. Overall, these changes show a reduction in revenue requirement of nearly 20 percent from the initial filing. The Company’s request for resource approval and recovery through the RTM is reasonable and in the public interest. The Combined Projects are the least cost alternative to meet customers’ needs today and into the future. As such, the higher standard for approval of the Combined Projects proposed by parties is inappropriate and unwarranted. The Company has also actively managed the costs of the Combined Projects through competitive solicitations, and mitigated project risks within the Company’s control.

The RTM is an interim mechanism to pass the benefits of the Combined Projects to customers until the resources are incorporated into base rates through a general rate case. The only “benefit” to the Company is the opportunity to recover its reasonable and prudent costs, like any other resource investment. The Company agrees that the RTM would be consistent with the soft cap in Utah Code Ann. § 54-17-303 and reflect actual costs up to a maximum of the final estimated costs from this proceeding.

SUPPLEMENTAL DIRECT TESTIMONY

Q. Have you updated the exhibits from your direct testimony to reflect the updated economic analysis for the Combined Projects, including the Wind Projects selected to the 2017R RFP final shortlist, as reflected in this supplemental direct

filing?

A. Yes. My original exhibits have been updated and are presented as Exhibit RMP___(JRS-1SD), Exhibit RMP___(JRS-2SD), Exhibit RMP___(JRS-3SD) and Exhibit RMP___(JRS-4SD).[1] These exhibits are revised with the updated economic analysis in Mr. Link's supplemental direct testimony, which reflects results from the 2017R RFP final shortlist. The exhibits are in the same format as in the initial filing, and calculate the monthly and annual revenue requirements and the overall rate impact for the Combined Projects that would be reflected in rates, including the proposed RTM.

Q. Please provide a summary of the updates in your revised exhibits.

A. The updates include changes in Utah's allocated share of the updated Combined Projects' construction costs, return, depreciation, Production Tax Credits ("PTCs"), taxes, and operating costs and benefits. Updated net power costs associated with the 2017R RFP final shortlist, an updated load forecast, system dispatch, and revised wind generation projections have also been included in the Energy Balancing Account ("EBA") pass-through calculation. Overall these changes show a reduction in revenue requirement of nearly 20 percent from the initial filing.

Q. Does the updated revenue requirement analysis incorporate the federal income tax rate change from 35 percent to 21 percent, as passed under the Tax Act of 2017?

A. Yes. As shown in Exhibit RMP___(JRS-4SD), line 5, the consolidated federal and state income tax rate has changed from the 37.951 percent used in my direct testimony to

[1] Exhibit RMP___(JRS-1SD) is included but is the same as Exhibit RMP__(JKL-1) presented in direct testimony.

24.587 percent, reflecting the change in the federal tax rate. Also, on line 6 of Exhibit RMP___(JRS-4SD), the PTC tax gross-up factor has been updated from 1.6116 in my direct testimony to 1.3260. These changes are incorporated in the revenue requirement results shown in Exhibit RMP___(JRS-2SD) and Exhibit RMP___(JRS-3SD).

Q. In addition to the updated economic analysis, are there any additional changes to the original exhibits?

A. Yes. Exhibit RMP___(JRS-2SD) and Exhibit RMP___(JRS-3SD) incorporate a revised carrying charge rate to be applied to the RTM Deferral Balance.

Q. Please explain.

A. The RTM deferral balance carrying charge presented in my direct testimony was based on the same carrying charge rate used in the Company's EBA filings, as specified in Electric Service Schedule No. 94, which is currently 6.0 percent. As discussed further below, the Company has revised the carrying charge rate to be consistent with the Commission's Carrying Charge Order in Docket No. 17-035-T02 and Docket No. 15-035-69, which is currently 4.19 percent. Exhibit RMP___(JRS-2SD) and Exhibit RMP___(JRS-3SD) have been updated to incorporate the revised carrying charge.

Q. What is the updated estimated rate impact associated with the Combined Projects, which would be reflected in rates through the RTM, in conjunction with the EBA?

A. The Company is projecting the Combined Projects' updated annual revenue requirement impact for the years 2020 to 2023 to be in the range of ($2) million to $31 million in Utah, as shown in Table 1 of Exhibit RMP___(JRS-2SD). The net rate impact would now be less than 1.6 percent for the first full year of operation.

Q. As a result of this updated economic analysis, has the Company's proposed

ratemaking treatment for interim recovery of costs through the RTM changed?

A. No. As discussed further below, the Company continues to propose recovery of costs through the RTM in order to concurrently match benefits and costs in rates.

REBUTTAL TESTIMONY

<u>**Resource Tracking Mechanism**</u>

Q. What should the Commission consider when determining whether to approve the Company's proposed energy resource decisions and RTM?

A. The Commission must determine that the Combined Projects are in the public interest and the RTM reasonably balances the Company's and customers' interests. These findings are supported by the results of the Company's 2017 Integrated Resource Plan, and Mr. Link's direct, supplemental direct and rebuttal testimonies explaining why the Company selected the Combined Projects as the least-cost, least-risk option to provide safe and reliable electric service to customers. The Combined Projects provide substantial benefits to customers that should be matched in rates with project costs. The proposed RTM combined with a future rate case is the best way to achieve that goal.

Q. Why is the RTM necessary?

A. The RTM is designed to match all costs and benefits over a short period of time. The RTM will allow the Company to track costs and deliver benefits to customers until the next rate case, while also allowing the Company to include the Combined Projects in base rates in a single general rate case filing. The RTM enables the Company to align near-term cost drivers into one general rate case, rather than rate cases over a multiple-year period. Without the RTM, all of the zero-fuel cost energy would flow to customers through the Energy Balancing Account mechanism ("EBA"), without recovery of the benefits of the production tax credits (“PTC”) or the costs that enable those benefits.

Q. Is the RTM intended to provide rate recovery over the life of the new resources?

A. No. The RTM is a short-term tracking mechanism that matches all benefits and costs until they are included in rates in the next general rate case. The RTM is not intended to be a permanent mechanism in place for the life of the Combined Projects.

Q. Ms. Ramas and Mr. Thomson recommend that the Commission reject the RTM and instead allow the Company to recover the costs of Combined Projects through a general rate case filing. (Ramas Direct, lines 129-133; Thomson Direct, lines 99-106.) Do you agree this approach is sufficient for the Combined Projects?

A. No. As both Ms. Ramas and Mr. Thomson recognize, the Company can file a general rate case using a future test year with projected data not to exceed 20 months from the proposed rate effective date.[2] Although the Company can request the use of a future test year, the Commission may not approve one, and parties, including OCS and UAE, have opposed future test years in the past.[3] Thus, it is highly uncertain whether the Company could implement the proposal to use a future test year to fully capture the costs and benefits of the Combined Projects in a single, timely general rate case, making timely cost recovery of this investment uncertain.

Q. Are there other concerns about relying on a single rate case with a future test period to recover the costs of the Combined Projects?

A. Yes. A forecast test period, as specifically suggested by Mr. Thomson, would not necessarily provide full and timely recovery of the costs. For example, Mr. Thomson suggests the Company could file a rate case July 1, 2019, using a future test period of

[2] Utah Code Ann. § 54-4-4(3).

[3] See Utah Docket No. 10-035-124, Order On Test Period (March 30, 2011).

calendar year 2020. (Thomson Direct, lines 99-103.) Since the Combined Project investment won't go into service until late in 2020, new rates using a calendar year 2020 test period would only reflect potentially one or two months of the investment using the Commission's traditional thirteen-month average rate base. The Company would need to immediately file another rate case in order to get the entire costs in rates.

Additionally, if all costs are deemed prudent, the results under either the RTM or a fully forecast rate period would be similar, however, the rate case would reflect projected costs of the Combined Projects in rates whereas the RTM would reflect actual costs, subject to the soft cap in Utah Code Ann. § 54-17-303. Therefore, the Company recommends the use of the RTM, which includes the opportunity for a prudence review of the project implementation of the expenditures before the costs are reflected in rates.

Q. Does Ms. Ramas recognize that there would be a mismatch between costs and benefits without the RTM?

A. Not specifically. However, without the RTM, capital costs would be absorbed by the Company, while a substantial portion of the benefits would automatically flow through to customers in the EBA.

Q. Do you agree that it would be reasonable to let the benefits go through the EBA without an RTM, or otherwise accounting for the corresponding costs?

A. No, the costs and benefits must be matched during the interim period. For example, it would not be reasonable to allow the Wind Projects' energy benefits to flow to customers through the EBA before the costs of the Combined Projects are reflected in rates. I continue to believe that the RTM is the most reasonable method for matching costs and benefits of the Combined Projects, but there may be reasonable ways of implementing Ms. Ramas' proposed approach. Nonetheless, the RTM would provide a bridge mechanism to allow the Company to balance the timing and test period for its next general rate case.

Q. Ms. Ramas argues that the Combined Projects, together with the Company's proposal to repower its wind fleet, are large enough investments that they should not be recovered outside of base rates, particularly because it has been so long since the Company's last general rate case. (Ramas Direct, lines 65-76.) How do you respond?

A. The Company recognizes that these are major investments and that this is a unique circumstance, which is why the Company has filed this request seeking Commission and stakeholder review of the resource opportunity. However, the Company has proposed the RTM in order to align the timing of the next general rate case in order to avoid back-to-back cases. The short-term use of the RTM does not unfairly impact customers since customers would be receiving the benefits matched with the associated costs of the projects.

Q. Ms. Ramas is also concerned that the use of the RTM will remove the Company's incentive to control costs between rate cases. (Ramas Direct, page 13, lines 295-298.) Does this concern apply to the RTM?

A. No. The Company agrees that the full costs of the Combined Projects should be subject to review before they are included in rates to verify that the Company prudently managed project implementation. The RTM does this by providing separate, annual filings that will follow the Commission process that allows for review by all interested and affected stakeholders.

Q. Ms. Ramas insists that the RTM will be overly complex in terms of matching costs and benefits. (Ramas Direct, lines 313-319.) Do you agree?

A. No. I do not agree that the RTM is overly complex. As demonstrated in my exhibits the RTM is a traditional revenue requirement calculation. This exact same calculation would need to be performed if the cost were considered in a general rate case. The RTM accomplishes the intent of the regulatory compact by matching the costs with the associated customer benefits.

Q. Mr. Mullins argues the RTM constitutes single-issue ratemaking, which he claims is "inherently unfair to ratepayers and should be avoided." (Mullins Direct, page 52, lines 15-17.) How do you respond?

A. Mr. Mullins' concerns are unfounded. Mr. Mullins argues that single-issue ratemaking is improper because it ignores the matching principle by isolating only increasing costs, without considering offsetting benefits. (Mullins Direct, page 52, lines 2-6). But the RTM is carefully designed to honor the matching principle by ensuring the costs and benefits of the Combined Project both flow through rates. Indeed, without the RTM, there will be a mismatch in that customers will receive the benefits without paying the costs.

<u>**Deferral vs. Accounting Order**</u>

Q. What is your position on Mr. Thomson's proposal that the Commission issue an accounting order to defer the costs and benefits of the Combined Projects until the next rate case, rather than approve the RTM? (Thomson Direct, page 6, lines 93-95.)

A. The RTM included in the EBA is a deferral mechanism with the deferral and amortization period more closely aligned. Under Mr. Thomson's proposal, the Commission would calculate the deferral in the same way as the RTM. Thus, the deferral of the incremental costs and benefits of the Combined Projects would be similar and the accounting treatment would essentially be the same as the RTM. However, the delay in the collections from deferring the costs of the Combined Projects, rather than implementing an annual true-up mechanism, creates several problems.

Q. Please describe the problems associated with using a deferral instead of the RTM to track the Combined Projects' costs and benefits.

A. First, the RTM ensures that costs and benefits are properly matched in the interim until the next rate case. The RTM deferral will end when Combined Projects' costs are reflected in base rates (except for the tracking of the variability of PTCs). A deferral as proposed by Mr. Thomson, on the other hand, could result in a later amortization that would increase the rate pressure on customers over and above base rate changes incorporating the investments.

Second, the RTM matches the costs and benefits so that the customers receiving the benefits are also paying the costs that generate those benefits. If the investment costs and PTCs are deferred, but the net power cost ("NPC") benefits flow through the EBA, a mismatch occurs and customers receive a windfall in the near term. This violates the matching principle for costs and benefits. Because Mr. Thomson's deferral results in a mismatch, I recommend using the RTM, which produces essentially the same result and avoids these issues. If Mr. Thomson's deferral approach is used, the NPC benefits of the zero-cost energy should be pulled out of the EBA and deferred as well.

Third, generally accepted accounting principles do not allow for the deferral of a return on investment that would be collected at some undetermined time in the future. With the RTM, the collection of the return component happens annually as part of the RTM's regular true-up process. The deferral approach would have the same total overall impact on customers; however, it would lead to complicated separate accounting, increased difficulty in auditing, and delayed inclusion of cost/benefit impacts for both customers and the Company.

Q. Mr. Thomson recommends the Commission use an accounting order "without the interest carrying charges or sur-credits." (Thomson Direct, lines 93-97.) Is this a reasonable recommendation?

A. No. Mr. Thomson does not explain the rationale for his proposal or justify its departure from established Commission precedent.

The elimination of a carrying charge, as proposed by Mr. Thomson, is unjustified. It is appropriate to apply a carrying charge to the balance of the RTM similar to the treatment for other mechanisms. As long as the Commission approves a reasonable carrying charge, however, the Company agrees to a deviation from the carrying charge used for the EBA. In Mr. Thomson's testimony, he comments that: "A reasonable carrying charge would be based on the Commission-approved carrying charge method."[4] The carrying charge in my exhibits has been updated using the Commission-approved carrying charge method rather than the carrying charge used in the EBA.

[4] Mr. Thomson Direct, lines 88-89.

Q. Why should the Commission approve the use of a mechanism to recover PTCs now, rather than in a future rate case as proposed by Ms. Ramas? (Ramas Direct, lines 272-274.)

A. Allowing recovery of the PTCs through the RTM better matches costs and benefits and ensures customers receive the benefits of the Combined Projects. The current PTCs included in base rates have already begun expiring, and the Company is not proposing to modify base rates to remove expiring PTCs. The Company is proposing to pass through 100 percent of the new PTC benefits through the RTM.

PTC benefits are tied to the output of the wind turbines. As the annual wind output varies, this results in changes to EBA-related NPC but currently the PTCs associated with the wind production are not captured. The energy impact of wind production is captured in the EBA; therefore, the Company is proposing to capture the impact on PTCs in the RTM. This will match the benefits and costs associated with varying wind production. Also, as previously mentioned, customers will receive all of the PTC benefits associated with the Combined Projects.

Project Benefits

Q. Do you agree with the parties' argument that the Combined Projects are discretionary, uneconomical and pose unacceptable risks to customers? (Zenger Direct, lines 248-268; Vastag Direct, lines 53-64; Mullins Direct, page 10, lines 17-20.)

A. No. The proposed resources are a least-cost opportunity to fill both a near-term and long-term resource need, so they should not be dismissed as discretionary. The Company's economic analysis also shows that customer benefits substantially outweigh the costs and that forgoing the time-sensitive opportunity to acquire the Combined Projects will result in higher customer costs in the long-term. In addition, the investment in the Combined Projects does not impose a greater risk on customers than other utility investments.

Moreover, in light of the off-ramps built into the Company's development schedule, approval of the resource decisions in this proceeding does not lock in the decision to proceed if circumstances change before the final notices to proceed, as discussed by Company witness Mr. Chad A. Teply.

Q. Mr. Peaco, Dr. Zenger, and Mr. Mullins also argue that the Company's proposal is inequitable because the Company's shareholders will receive substantially more benefits than customers. (Peaco Direct, lines 227-277; Mullins Direct, page 9, line 1-2; Zenger Direct, lines 102-125.) Do you agree with this characterization?

A. No. The purported shareholder benefit is the capital cost incurred to fund the Combined Projects. A basic premise of ratemaking, however, is that "a capital-attracting rate of profit is here considered a part of the necessary cost of service."[5] The cost of capital is no different than any other prudent cost recoverable in rates if incurred to provide utility service. It is inaccurate to say that shareholders are receiving a greater benefit than customers based on the fact that shareholders recover the costs incurred to provide utility service.

The Company has shown it can deliver additional generation to customers at a lower cost than the alternatives, resulting in a net benefit to customers. The customer benefits assume that shareholders recover the full cost of the Combined Projects

[5] James C. Bonbright, Albert L. Danielsen, & David R. Kamerschen, *Principles of Public Utility Rates*, 112 (2d ed. Public Utilities Reports 1988).

investment, including capital costs.

After the next rate case, the prudent costs and benefits of the Combined Projects will be included in the Company's full revenue requirement. However, there is no guarantee the Company will recover its full cost of service related to the investment. The Company must prudently manage its costs to achieve the full return allowed by the Commission.

Q. Has the Commission previously approved resource acquisitions based on their economic benefits to customers?

A. Yes. The Commission has allowed cost recovery for the Cholla, Craig and Hayden, and Chehalis power plants. All of these were economic opportunities, and in every case, the Commission determined these facilities were in the best interest of customers, *i.e.*, acquiring these resources provided net savings to customers. Although there were customer risks with the resource decision in each case, the Commission allowed full recovery. Consistent with this precedent, if the Commission determines the Combined Projects provide customer benefits, based on what is known today, it should allow full recovery of the costs associated with the Combined Projects.

Q. Has any party to this case previously supported similar economic resource decisions?

A. Yes. When the Company acquired the Chehalis plant in 2008, DPU and UAE both supported the Company's decision to acquire the plant ahead of need. *In the Matter of the Request of Rocky Mountain Power for a Waiver of the Solicitation Process and for Approval of Significant Energy Resource Decision*, Docket No. 08-035-35, Report and Order at 9 (Aug. 1, 2008). In its testimony, DPU noted that the Company's "latest IRP

[had] no expectation that a major thermal generation plant would be acquired between 2007 and 2012" and that the "Chehalis plant would replace a similar natural gas CCCT 500 MW plant that was to be built or acquired in the later time frame." Docket No. 08-035-35, Exhibit No. DPU 1.0, Peterson Direct, page 10, lines 205-208. DPU supported the acquisition ahead of need, in part, because DPU believed it was in the public interest for the Company to "control generation assets rather than to purchase power on the wholesale market." *Id.*, page 11, lines 226-230. DPU testified that there were considerable risks associated with relying on market transactions and that the flexibility provided by owning the plant provided a benefit, even though it could not be directly quantified. *Id.*, page 11, lines 236-238; page 12, lines 255-259.

Q. What conditions does the Company accept related to its request for approval of its resource decisions and RTM?

A. The Company agrees that approval of the Combined Projects and RTM would be conditional on the circumstances known at the time of approval. If there is a change in circumstances that may materially affect the Combined Projects, the Company agrees to return to the Commission for review, as provided in Utah Code Ann. § 54-17-304.

In addition, the law allows the Commission to determine the maximum amount of costs to be included in rates (Utah Code Ann. § 54-17-303), which is effectively a soft cap. The Company agrees that the RTM would be consistent with that soft cap and reflect actual costs (and benefits), up to a maximum of the final estimated costs from this proceeding. The Company would apply for prudence determination of any variances from the estimates in the next rate case, as provided in Utah Code Ann. § 54-17-303(1)(c).

Q. Bela Vastag on behalf of the OCS recommends that in light of "the current level of uncertainty in the Multi State Process" the Commission should approve a maximum cost for Utah using the existing allocations methods, if the Commission approves the Combined Projects. (Vastag Direct, lines 65-73.) Do you think this is a reasonable argument and recommendation?

A. No. The OCS is essentially asking the Commission to pre-judge the outcome of the Multi-State Process ("MSP") discussions that are underway with a presumption that Utah customers will be worse off with any changes in allocation methods. MSP discussions are balancing a number of considerations and complexity among the states but should not be viewed and judged in isolation to any one resource decision. The impacts to Utah from changes to allocation methods for all resources will be considered in discussions among the states in MSP. Pre-determining future ratemaking treatment for one set of resources would be contrary to efforts currently underway. Moreover, the OCS recommendation to set a maximum cost to Utah using the current allocation methods fails to recognize that the current allocation methods use dynamic allocation factors that fluctuate up and down and doesn't address whether benefits would also be capped to Utah. As such, the OCS recommendation is incomplete and inconsistent with the current allocation methods.

Q. Does this conclude your supplemental direct and rebuttal testimony?

A. Yes.