ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 330
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February 1, 2018

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: Docket No. 17-035-39
APPLICATION FOR APPROVAL OF RESOURCE DECISION TO REPOWER WIND FACILITIES

In accordance with the Amended Scheduling Order issued by the Utah Public Service Commission on November 27, 2017, Rocky Mountain Power hereby submits for electronic filing its Supplemental Direct Testimony. Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

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By regular mail: Data Request Response Center
PacifiCorp
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Portland, OR 97232

Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle R. Steward
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that on February 1, 2018, a true and correct copy of the foregoing was served by electronic mail and overnight delivery to the following:

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Katie Savarin

Katie Savarin
Coordinator, Regulatory Operations

Rocky Mountain Power
Docket No. 17-035-39
Witness: Cindy A. Crane

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Supplemental Direct Testimony of Cindy A. Crane

February 2018

Q. Are you the same Cindy A. Crane who previously provided direct and rebuttal testimony in this case on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. In my testimony, I support the Company's request that the Public Service Commission of Utah ("Commission") approve the wind repowering project. I provide an update on the policy support for the Company's decision to repower its wind facilities, and describe a modest refinement to the Company's requested relief based on the updated economic analysis.

Q. Please summarize your testimony.

A. The repowering project continues to advance the public interest and is expected to provide substantial net benefits to customers. As the project has progressed, the contract negotiations and technical studies are nearing completion—meaning that the expected costs and performance for the repowered facilities are now more certain. The updated economic analysis, which accounts for updated market conditions, updated cost and performance metrics, and federal corporate income tax reform, shows that the repowering project is expected to provide customer benefits under all price-policy scenarios.

Based on the changes in the federal income tax code, the Company proposes one refinement to its proposed ratemaking treatment. The Company requests that the proposed Resource Tracking Mechanism ("RTM") continue to be capped in the early years, but that the revenue requirement impact associated with the changes to the federal tax code that exceed the cap be deferred for future ratemaking treatment.

SUPPLEMENTAL DIRECT TESTIMONY

Q. Does the Company's supplemental direct testimony provide the updated economic analysis that was agreed to when the procedural schedule in this case was amended?

A. Yes. As described by Company witness Mr. Rick T. Link, the Company has updated the project-by-project economic analysis to account for changes in the federal corporate income tax rate, updated market prices for natural gas and carbon dioxide, and updated cost and performance information for the wind repowering project. *See In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Repower Wind Facilities*, Docket No. 17-035-39, Unopposed Motion to Amend Procedural Schedule at ¶4 (Nov. 22, 2017) (describing the updated analysis that would be provided in the Company's supplemental testimony). The overall economics of the wind repowering project remain favorable in all price-policy scenarios and demonstrate a high likelihood that repowering will provide significant customer benefits.

Q. Are the expected costs and benefits of the repowering projects now more certain?

A. Yes. As described by Mr. Timothy J. Hemstreet, the technical studies and contract negotiations are both nearing completion and both processes have largely confirmed the Company's prior estimates—the cost of the repowering project increased by only 1.6 percent, while the expected incremental energy production decreased by only 0.2 percent. Because the costs and performance of the repowered facilities are now more certain, the expected benefits modeled by Mr. Link are also more certain and the overall risks associated with repowering have decreased.

Q. Has the change in the federal corporate income tax rate modified the Company's proposed rate treatment for the repowering project?

A. Yes. The Company still requests that the Commission approve its proposed RTM as an interim measure to better match the costs and benefits of the repowering project in customer rates and prevent the need for year-after-year rate cases. In addition, the Company stands by its proposal to cap the RTM. As described by Ms. Joelle R. Steward, however, even though repowering still provides customer benefits over the life of the project, tax reform has changed the revenue requirement impact of the repowering project such the Company does not expect it to produce a revenue requirement decrease until 2022. Because of the changes in the near-term rate impacts in 2020-2021 due to tax reform, the Company proposes to separately defer the net costs in excess of the cap related to tax law changes, and seek recovery through the offsets to the deferral for the impacts from tax reform that the Commission is addressing in a separate proceeding (Docket No. 17-035-69).

Q. Does this conclude your testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Docket No. 17-035-39
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Supplemental Direct Testimony of Timothy J. Hemstreet

February 2018

SUPPLEMENTAL DIRECT TESTIMONY OF TIMOTHY J. HEMSTREET

Q. Are you the same Timothy J. Hemstreet who previously provided testimony in this case on behalf of PacifiCorp dba Rocky Mountain Power (the "Company")?

A. Yes.

PURPOSE AND SUMMARY OF SUPPLEMENTAL DIRECT TESTIMONY

Q. What is the purpose of your supplemental direct testimony in this proceeding?

A. My supplemental direct testimony provides the latest technical and commercial information on the Company's wind repowering project. This update includes developments since the Company's rebuttal filing in October 2017, and surrebuttal filing in November 2017.

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

A. I provide an update on the following key issues:

- Changes in turbine specifications due to the completion of the technical review of all facilities that are proposed to be repowered;
- Changes in project costs and energy benefits as a result of the completion of technical design and foundation review for all of the facilities, and now-known transmission capacity increases;
- The status of project permitting and the contracting process the Company has undertaken for installation of turbines to be supplied by Vestas-American Wind Technology, Inc. ("Vestas") to facilitate the repowering project; and
- Updated safe harbor cost sensitivity analysis and schedule for the repowering project.

Q. Please summarize your testimony.

A. Since rebuttal and surrebuttal testimony were filed in the fall of 2017, the Company has observed continued reduction in wind repowering project risks and uncertainties as the technical studies conclude and contracting progresses. The Company has a) updated its energy production estimates to reflect recent project-specific changes and additional available data, with only a small net change in production; b) confirmed the need and scope of required facility retrofits, with project costs remaining within 1.6 percent of estimates included in my rebuttal testimony; and c) completed significant permitting requirements for 11 of the 12 facilities. Despite the delay in the original procedural schedule in this case, the Company remains confident that it can qualify for the production tax credits ("PTCs"), and deliver the repowering project on-time at or below the cost estimates included here. Even after accounting for recent changes to the federal income tax rates, the customer benefits resulting from the repowering project remain robust and the Company remains on track to deliver these benefits to customers.

UPDATE ON COST AND PERFORMANCE

Q. Have there been any changes to the Company's estimates of run-rate capital expenditures for the repowering or status quo cases as compared to the rebuttal filing?

A. No. The Company's estimates of run-rate capital expenditures for both cases are unchanged.

Q. Have there been any changes in the Company's operations and maintenance cost assumptions since the time of your rebuttal testimony?

A. No. There have been no changes in operations and maintenance cost assumptions and costs for the status quo case remain unchanged. However, the energy estimates for certain facilities have changed, as described later in my testimony. The operations and maintenance costs for the repowering case have adjusted slightly for those facilities as a result of changed land lease payments that are tied to energy production.

Q. Have there been any changes to turbine specifications for the wind facilities since your previous testimony?

A. Yes. The specified turbine for the Leaning Juniper facility has changed [redacted]

Q. Why was this change made?

A. As site-specific climactic conditions and design loads for this project site were evaluated and developed, the turbine supplier made the change to ensure the turbine loading is within the allowable load limits of the existing towers and foundations at the project site.

Q. Does the reduction in nameplate capacity of the specified turbine type impact the amount of energy expected from this repowered facility?

A. Yes. The reduction in nameplate capacity reduces the estimated generation increase of the repowered facility from 30.0 percent to 27.0 percent—a three percent reduction.

Q. Has this reduction in energy been factored into the Company's economic analysis for this facility?

A. Yes. The economic analysis of Company witness Mr. Rick T. Link accounts for the updated generation expected for the Leaning Juniper facility.

Q. Does the change in turbine type for the Leaning Juniper facility impact the cost of repowering that facility?

A. Yes. The change in turbine specification has also resulted in revised pricing from the turbine supplier that has lowered the costs for turbine supply at this project.

Q. Are there any other changes to the estimated energy output from the repowering project, as compared to the estimates in your previous testimony?

A. Yes. When my prior testimony was filed, only one year of historical data was available to estimate the energy increases for the Glenrock I, Glenrock III, and Rolling Hills facilities. Since then, the Company has been able to evaluate additional years of data for these facilities and complete further analysis. The Company's estimated energy increase for these facilities is now based on four years of historic data, consistent with the methodology and data history used for all the other facilities.

Q. Has this changed the energy production estimates for the Glenrock I, Glenrock III, and Rolling Hills facilities?

A. Yes, slightly. The estimated energy production for the Glenrock I, Glenrock III, and Rolling Hills facilities decreased by 1.1 percent, 0.5 percent, and 0.3 percent, respectively. These changes in the energy production estimates are shown in Confidential Exhibit RMP___(TJH-1SD). These changes have also been factored into the Company's economic analysis presented in Mr. Link's supplemental direct testimony.

Q. Are there any other changes in the energy production estimates included in this supplemental direct filing?

A. Yes. Transmission studies for the Marengo I and Marengo II facilities have advanced to the point where the Company is now confident that an interconnection agreement can be executed with the Company's transmission function that will allow the repowered Marengo facilities to deliver their full repowered energy capability to customers. This results in a 1.0 percent and 2.2 percent increase in the estimated energy production from the Marengo I and Marengo II facilities, respectively. The Company's economic analysis includes this increased energy production.

Q. What is the net change in estimated energy production for the repowering project given decreases at Glenrock I, Glenrock II, Rolling Hills, and Leaning Juniper, and increases at Marengo I and Marengo II?

A. There is only a small net change. In my previous testimony, I estimated an energy production increase of 25.9 percent for the repowering project; my current estimate is an energy production increase of 25.7 percent.

Q. Have the costs for the required transmission system modifications for the Marengo facilities been factored into the financial analysis?

A. Yes. The costs for the required transmission system modifications needed to interconnect this additional capacity--which the transmission studies have estimated at $180,000--are now included in the cost estimates for the Marengo facilities included in this supplemental direct filing.

Q. Does the Company now know whether the transmission interconnection agreements at the other facilities can be modified to increase the amount of energy that can be delivered from those facilities?

A. No. Transmission studies have not yet advanced at the Wyoming wind facilities to the point where the Company knows whether this additional capacity will be available for these facilities. For this reason, the Company's economic analysis still shows the Wyoming projects operating under their current interconnection agreement limits. Finally, the Company does not anticipate additional transmission capacity will be available for the Leaning Juniper and Goodnoe Hills facilities due to transmission constraints.

Q. Has the Company now completed an evaluation of the foundations at all wind repowering sites and confirmed that the foundations are suitable for the new turbines?

A. Yes. Since my prior testimony was filed, site-specific turbine design and foundation analyses have now been completed for the Goodnoe Hills and Leaning Juniper facilities. When my prior testimony was filed, site-specific foundation load specifications for these facilities were not yet available and the Company had not yet verified that the foundations at these facilities were suitable for the specified repowering turbines. Black & Veatch, Inc., has now evaluated the foundations at the Leaning Juniper and Goodnoe Hills facilities and determined that the foundations will be suitable for the repowered turbines following a standard retrofit that will add strength to these foundations. This strengthening will allow the foundations to resist the loads of the larger turbines for an additional 30-year service life following repowering, similar to all the other facilities previously evaluated.

Q. Was the cost of these foundation retrofits previously included in the Company's cost estimates for the Leaning Juniper and Goodnoe Hills facilities?

A. No. The cost was not included because we did not know the retrofits would be necessary. The Company has now included the estimated cost of these foundation retrofits into the costs for these repowered facilities, which have been evaluated in the project-by-project economic analysis described in the testimony of Mr. Link. Changes in project costs as compared to those in my prior testimony are also shown in Confidential Exhibit RMP___(TJH-1SD). The only material cost changes are associated with the Marengo facilities, for increased interconnection agreements and updated installation costs, and Leaning Juniper and Goodnoe Hills, reflecting the costs of foundation retrofits and updated turbine installation costs. In addition, the reduction in turbine supply costs for Leaning Juniper offsets the cost increases for this facility.

Q. How much have project costs increased as compared to costs included in your prior testimony?

A. Project costs have increased by $17.6 million—or approximately 1.6 percent—to $1.10 billion for the Company's base repowering scenario which assumes transmission interconnection agreements in Wyoming are not modified. The Company continues to expect $36 million in project upgrade costs to allow the Wyoming facilities to deliver additional energy under modified interconnection agreements, for a total cost of $1.137 billion. As before, ongoing transmission studies will determine the costs of any necessary upgrades to the transmission system to interconnect this additional project capacity.

Q. Given the increased costs for the projects that will employ Vestas turbines (*i.e.*, Leaning Juniper, Goodnoe Hills, Marengo I, and Marengo II), is the Company still confident that it will have sufficient safe harbor wind turbine generator equipment purchased in 2016 to satisfy the five percent safe harbor requirement and qualify the projects for 100 percent of the value of the PTCs?

A. Yes. As a result of the increased costs of repowering the Goodnoe Hills facility due to the necessary foundation retrofit, the Company has changed its allocation of safe harbor nacelles to increase the number of nacelles for the Goodnoe Hills facility. This will allow all wind facilities to maintain an adequate safe harbor percentage so that project costs that are not yet contractually fixed could escalate 65 percent or more with the facilities still having sufficient safe harbor equipment. Table 1 below shows the cost overrun sensitivity of the various facilities, similar to that provided in my rebuttal testimony, and demonstrates that all facilities have adequate safe harbor equipment. As discussed in my rebuttal testimony, the Company also has access to additional Vestas safe harbor equipment from Berkshire Hathaway Energy of the same type as the safe harbor nacelles purchased for the repowering project in December 2016. If necessary, the Company can supplement the safe harbor equipment in order to ensure there is adequate safe harbor equipment to qualify for 100 percent PTCs.

Confidential Table 1

Cost Overrun Sensitivity of Repowering Facilities to Meet Five Percent Safe Harbor

Wind Project	Total Project Cost Applicable to Five Percent Safe Harbor	Current Safe Harbor Percentage (%)	Cost that are Fixed with Turbine Suppliers ($000s)	Turbine Supplier Fixed Costs (%)	Costs Not Yet Contractually Fixed ($000s)	Amount that Non-Fixed Costs Can Increase and Meet 5% Safe Harbor (%)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5300%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5200%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4800%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4400%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4000%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3450%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3450%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3300%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	175%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	110%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	100%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	65%

UPDATE ON PERMITTING AND CONTRACT STATUS

Q. Since the Company's rebuttal filing, has progress been made on permitting for the Company's repowering project?

A. Yes. Since the Company filed rebuttal testimony, Klickitat County, Washington has determined that no additional permitting through its Planning Department is necessary for the Company's proposed repowering of the Goodnoe Hills facility. With this approval, 11 of the 12 facilities have been approved by the relevant county or Industrial Siting Division. The Company does not anticipate any issues with obtaining the remainder of any necessary permits and authorizations.

Q. In your October 2017 rebuttal testimony, you noted the Company had not executed a contract for the installation services for facilities employing Vestas turbines. (Hemstreet Rebuttal, lines 95-106.) What is the status of that process?

A. The Company issued a request for proposals in early December 2017 and received qualified bids for installation of Vestas turbines from several wind energy construction contractors in mid-January 2018. The Company is still evaluating these proposals to determine which proposal provides the best value to customers.

Q. Has the Company factored the information gained from the responsive bids into its cost estimates for constructing the facilities employing Vestas turbines?

A. Yes, the Company's cost estimates have been updated to reflect cost information gained through the competitive bid process for installation, foundation retrofits (where necessary), and other site construction services that will be provided by the successful wind energy contractor.

Q. When factoring in cost information from the competitive bids for installation and foundation retrofit work (where necessary) for the Vestas projects, did the Company simply take the costs from the lowest bid and incorporate that into the Company's cost estimates?

A. No. Because the Company has not yet fully evaluated the bids or completed negotiations with the bidders, the Company did not simply rely on the lowest bid submitted to develop its revised cost estimates. Instead, the Company excluded the low bid in the event it was non-responsive and used pricing reflective of the average of the next three lowest cost proposals. For this reason, I am confident that these construction services can be contracted at pricing equal to or better than the pricing included in the

Company's current cost estimates.

Q. When does the Company anticipate having the construction contract for the Vestas turbines completed?

A. The Company expects to have a fully negotiated construction contract with the successful bidder completed by the end of March 2018.

Q. Given the delay in the schedule of this proceeding to allow recent tax law changes to be factored into the Company's economic analysis, do you foresee schedule risks that may now impact the ability of the repowering project to be constructed in the timeframe originally described in your direct testimony?

A. No. The Company continues to work with its turbine suppliers—General Electric, Inc. and Vestas—to ensure timely delivery of the repowering project while accommodating the delay in this proceeding. At this time, the construction schedule for the projects, which shows completion of all facilities in 2019 except Dunlap, remains achievable given the anticipated timing for the Commission's final order on the Company's request. An updated project schedule for the repowering project is included in Confidential Exhibit RMP___(TJH-2SD).

Q. With the recent tax law changes, are you aware of any provisions that have changed the ability of the facilities to qualify for the full value of PTCs as described in your direct and rebuttal testimony?

A. No. As more fully described by Company witness Ms. Nikki L. Kobliha, the recent tax law changes have not impacted the ability of the repowering project to qualify for the full value of PTCs under Internal Revenue Service guidance (including the safe harbor requirements or the 80/20 rule).

Q. Does this conclude your supplemental direct testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(TJH-1SD)
Docket No. 17-035-39
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Direct Testimony of Timothy J. Hemstreet

Repowering Project – Generation Increases

February 2018

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Rocky Mountain Power
Exhibit RMP___(TJH-2SD)
Docket No. 17-035-39
Witness: Timothy J. Hemstreet

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Direct Testimony of Timothy J. Hemstreet

Repowering Project – Schedule

February 2018

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

REDACTED
Rocky Mountain Power
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Supplemental Direct Testimony of Rick T. Link

February 2018

Q. Are you the same Rick T. Link who previously provided direct and rebuttal testimony in this case on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. In my testimony, I provide updated economic analysis demonstrating that the wind repowering project remains beneficial to customers after taking into account new federal corporate income tax rates, and updated information on costs, performance, and market prices.

Q. Please summarize your supplemental direct testimony.

A. I summarize my updated and expanded economic analysis of the wind repowering project, developed in response to changes in federal income tax law. I demonstrate that:

- The updated economic analysis continues to show net customer benefits in all of the scenarios analyzed.
- The wind repowering project will produce present-value net customer benefits, based on updated economic analysis over the remaining life of the repowered wind facilities, ranging between $121 million to $466 million.
- Present-value gross customer benefits calculated over the remaining life of the repowered wind facilities range between $1.14 billion and $1.48 billion, which compares to present-value project costs totaling $1.02 billion.
- These net and gross customer benefits are conservative, as they do not account for potential incremental benefits from renewable energy credits ("RECs") and

understate the potential benefits from reduced carbon dioxide (“CO_2”) emissions.

- When measured over a 20-year period, the present value of net customer benefits from wind repowering range between $139 million and $273 million, which accounts for the nominal value of federal production tax credits (“PTCs”), but does not account for the value of incremental energy output that will increase significantly beyond 2036.

UPDATED ECONOMIC ANALYSIS

Q. Did the Company update its economic analysis supporting the wind repowering project?

A. Yes. The economic analysis was updated to reflect more current assumptions, consistent with the agreement set forth in the Unopposed Motion to Amend the Procedural Schedule filed by the Company on December 14, 2017.

Q. What assumptions did the Company update before refreshing its economic analysis of the wind repowering project?

A. The models were updated to reflect: (1) updated cost-and-performance assumptions for the wind repowering project; (2) current price-policy scenario assumptions, including more current natural gas and CO_2 prices; and (3) recent changes in the federal tax rate for corporations.

Q. Please describe the updated cost-and-performance estimates for the wind repowering project.

A. Cost estimates for the wind repowering project have been updated consistent with findings from technical review studies. As described in the supplemental direct testimony of Company witness Mr. Timothy J. Hemstreet, these technical review studies have led to a change in turbine specifications at the Leaning Juniper facility to ensure turbine loading remains within allowable limits. Mr. Hemstreet also explains that project costs have been updated to account for the need to strengthen foundations at the Leaning Juniper and Goodnoe Hills facilities. Mr. Hemstreet further explains that updated cost assumptions reflect information received through a competitive bidding process for installation, foundation retrofits, as applicable, and other construction services needed to complete the wind repowering project.

As discussed by Mr. Hemstreet, performance estimates for the wind repowering project have been updated to reflect: a) the change in turbine specifications at the Leaning Juniper facility; b) a longer historical period of data used to estimate increased energy production at the Glenrock I, Glenrock III, and Rolling Hills facilities; and c) increased incremental energy production at the Marengo I and II facilities to reflect expected modifications to the interconnection agreement.

In my rebuttal testimony, I explained that the Company did not receive verification that [redacted] equipment could be used on General Electric ("GE") sites (all sites except Marengo I, Marengo II, Leaning Juniper, and Goodnoe Hills) until after we had initiated the economic analysis summarized in that testimony. Consequently, the bulk of the economic analysis presented in my rebuttal testimony assumed the use of [redacted] equipment on all GE sites, and the [redacted] equipment was analyzed as a sensitivity. The updated economic analysis summarized here assumes the [redacted] equipment is used on all GE sites.

After accounting for all of these updates, the capital investment for the wind repowering project is $1.101 billion, which is approximately $18 million (1.6 percent) higher than the $1.083 billion cost assumed in the economic analysis summarized in my rebuttal testimony. The updated incremental energy output from the wind repowering project is 25.7 percent (738 gigawatt-hours ("GWh") per year)—up from the 24.9 percent (714 GWh per year) assumed in the economic analysis summarized in my rebuttal testimony.[1] The cost-and-performance assumptions for the wind facilities studied in the updated economic analysis are summarized in Confidential Exhibit RMP___(RTL-1SD).

Q. Please describe the new price-policy assumptions included in the updated economic analysis.

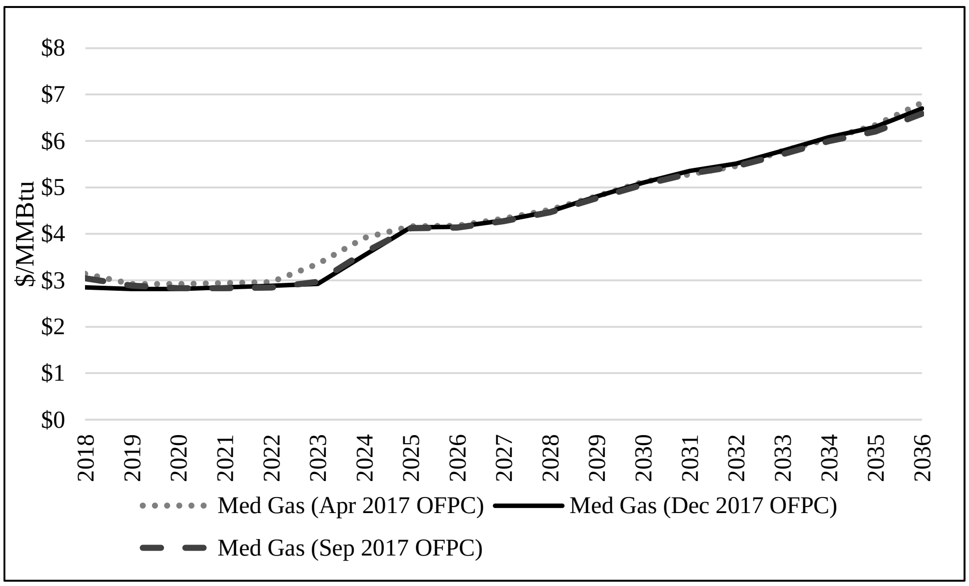
A. In my direct testimony, I described nine price-policy scenarios, developed by pairing three natural-gas price forecasts (low, medium, and high) with three CO_2 price forecasts (zero, medium, and high). The medium natural-gas price assumptions were derived from the Company's official forward price curve ("OFPC"). In the economic analysis summarized in my direct testimony, the Company used its April 26, 2017 OFPC. In the economic analysis summarized in my rebuttal testimony, the Company used its September 30, 2017 OFPC.

The Company's most recent OFPC is dated December 29, 2017, which reflects more current market forwards and an updated forecast from [redacted]. Figure 1-SD compares Henry Hub natural-gas prices from the April 26, 2017 OFPC and the

[1] In my rebuttal testimony, the economic analysis assumed a 24.9 percent incremental energy output. In addition, I provided a sensitivity analysis using the 25.9 percent incremental energy output discussed in Mr. Hemstreet's rebuttal testimony. As explained in the rebuttal testimony, the 25.9 percent increase was based on updated turbine specifications that were confirmed just before the rebuttal testimony was filed.

September 30, 2017 OFPC, which were used to support the economic analysis in my direct and rebuttal testimony, with Henry Hub natural-gas prices from the updated December 29, 2017 OFPC. Over the period 2018 through 2036 and using the most current discount rate, the nominal levelized price for Henry Hub natural-gas prices has decreased by less than one percent from $3.95 per million British thermal units ("MMBtu") as assumed in my rebuttal testimony to $3.94/MMBtu.

Figure 1-SD. Comparison of OFPC
Henry Hub Natural-Gas Price Forecasts



The updated OFPC reflects market forwards as of December 29, 2017, over the period January 2018 through January 2024. The decrease in levelized prices between the updated OFPC and the April OFPC used in the Company's original economic analysis is primarily driven by a reduction in market forwards. Prices in the updated market fundamentals forecast from [redacted], which are used exclusively in the OFPC beyond January 2025, track closely with those assumed in the April 2017 OFPC. The Company continues to blend market forwards from month 61 (February 2023) through month 72 (January 2024) with the fundamentals-based forecast from month 85

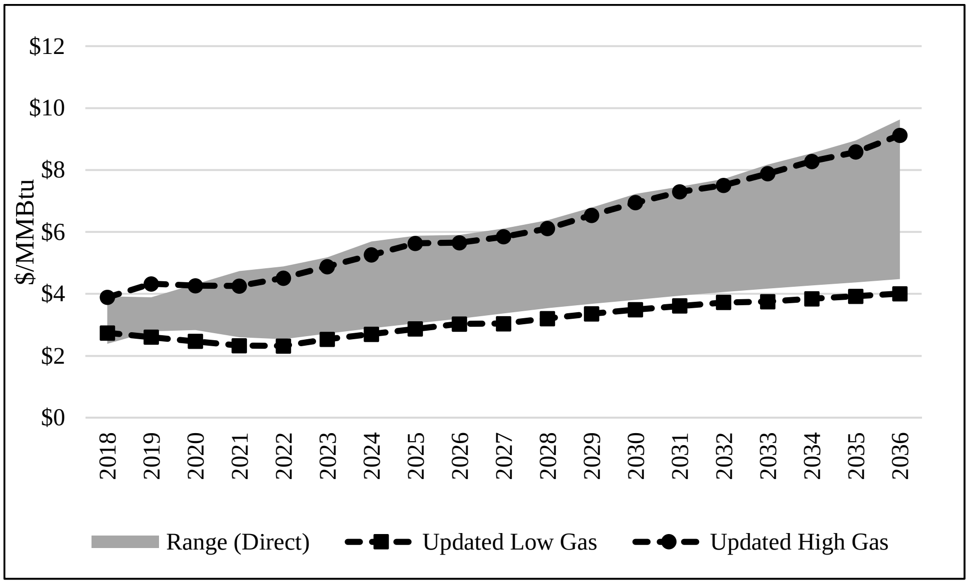
(February 2025) through month 96 (January 2026) to establish prices in month 73 (February 2024) through month 84 (January 2025).

Q. Did the Company update the low and high natural-gas price scenarios used in the updated economic analysis?

A. Yes. Consistent with the Company's approach to develop low and high natural-gas price scenarios used in the original economic analysis, low and high natural-gas price assumptions were updated after reviewing the range in more recent forecasts developed by [redacted], [redacted], and the U.S. Department of Energy's Energy Information Administration. Confidential Exhibit RMP___(RTL-2SD) shows the range in natural-gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios in the Company's updated economic analysis of the wind repowering project.

Figure 2-SD shows the range between the low and high natural-gas price scenarios used in the Company's original economic analysis alongside the updated low and high natural-gas price assumptions. Nominal levelized prices in the low and high scenarios are $2.95/MMBtu (down by approximately seven percent) and $5.60/MMBtu (down by approximately four percent), respectively.

Figure 2-SD. Updated Low and High Natural-Gas Price Assumptions



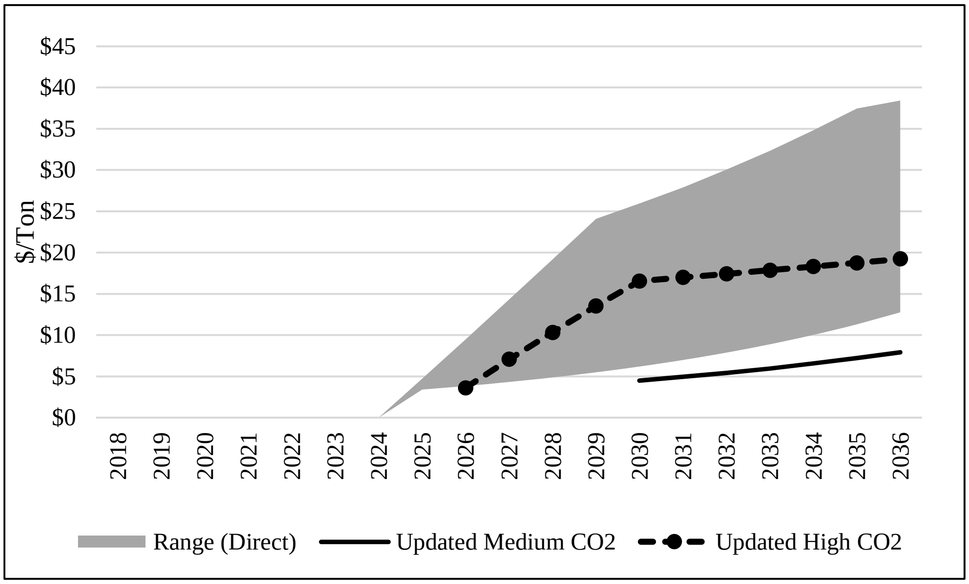
Q. Did the Company update its CO_2 price scenarios used in its updated economic analysis?

A. Yes. As with natural-gas price assumptions and consistent with the Company's approach to develop low and high CO_2 price scenarios used in the original economic analysis, low and high CO_2 price assumptions were updated after reviewing the range in more recent forecasts developed by [redacted] and [redacted]. To bracket the low end of potential-policy outcomes, the Company continues to assume there are no future policies adopted that would require incremental costs to achieve emission reductions in the electric sector. For this scenario, the assumed CO_2 price is zero.

Figure 3-SD shows the range between the medium and high CO_2 price scenarios used in the Company's original economic analysis alongside the updated medium and high CO_2 price assumptions. The updated medium and high CO_2 price assumptions are lower and start later relative to the assumptions summarized in my direct testimony. Updated CO_2 prices in the medium scenario begin in 2030 (five years later) at $4.49/ton

and rise to \$7.95/ton by 2036. Updated prices in the high scenario begin in 2026 (one year later) at \$3.62/ton, rise to \$16.55/ton by 2030, and reach \$19.23/ton by 2036.

Figure 3-SD. Updated Medium and High CO_2 Price Assumptions



Q. Please describe the updated federal tax rate for corporations that was included in the updated economic analysis of the wind repowering project.

A. The Company's updated analysis assumes a 21 percent federal income tax rate as provided in H.R. 1, which was passed by Congress on December 20, 2017, and became law on December 22, 2017. Based on an assumed net state income tax rate of 4.54 percent, the effective combined federal and state income tax rate used in the updated analysis is 24.587 percent.

Q. Please describe how the effective combined federal and state income tax rate assumption is applied in the System Optimizer ("SO") model and the Planning and Risk model ("PaR") in the updated economic analysis.

A. As described in my rebuttal testimony, the effective combined federal and state income tax rate affects the Company's post-tax weighted average cost of capital, which is used as the discount rate in the SO model and PaR. With the changes in tax law, the Company's discount rate has been updated from 6.57 percent to 6.91 percent.

The modified income tax rate also affects the capital revenue requirement for all new resource options available for selection in the SO model. As described in my rebuttal testimony, capital revenue requirement is levelized in the SO and PaR models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. This is achieved through annual capital recovery factors, which are expressed as a percentage of the initial capital investment for any given resource alternative in any given year. Capital recovery factors, which are based on the revenue requirement for specific types of assets, are differentiated by each asset's assumed life, book-depreciation rates, and tax-depreciation rates. Because capital revenue requirement accounts for the impact of income taxes on rate-based assets, the capital recovery factors applied to new resource costs in the SO model were updated for each of the Company's system simulations.

Finally, the updated income tax rate affects the tax gross-up of all PTC-eligible resources. As noted in my direct testimony, the current value of federal PTCs is $24/megawatt-hour ("MWh"), which equates to a $38.68/MWh reduction in revenue requirement assuming an effective combined federal and state income tax rate of 37.95 percent. The updated combined federal and state income tax rate reduces the revenue requirement associated with federal PTCs from $38.68/MWh to $31.82/MWh, adjusted for inflation over time. The impact of the updated income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model.

Q. How were these assumption updates captured in the updated economic analysis of the wind repowering project?

A. The Company updated the SO model and PaR to reflect these updated assumptions. As was done in the original analysis summarized in my direct and rebuttal testimony, these models were used to calculate the present value revenue requirement differential ("PVRR(d)") between a simulation with and without the wind repowering project after applying the modeling updates. These simulations continue to cover a forecast horizon out through 2036. The Company also updated its calculation of the PVRR(d) from the change in nominal revenue requirement due to the wind repowering project through 2050.

Q. In addition to the assumption updates described above, did the Company change how it applied federal PTC benefits in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. Yes. The Company applied PTC benefits on a nominal basis rather than on a levelized basis. This approach better reflects how the federal PTC benefits for the repowered assets will flow through to customers and aligns the treatment of federal PTC benefits in the system modeling results extending out through 2036 with the nominal revenue requirement results extending out through 2050.

Q. Did the Company continue to apply revenue requirement associated with capital costs on a levelized basis in its system modeling using the SO model and PaR configured to forecast system costs through 2036?

A. Yes. When setting rates, revenue requirement from capital costs is depreciated over the book life of the asset, effectively spreading the cost of capital investments over the life of the asset. Because revenue requirement from capital projects is spread over the life of the asset in rates, these costs continue to be treated as a levelized cost in the SO model and PaR simulations. As was done in the Company's original economic analysis to estimate the nominal revenue requirement impacts from the wind repowering project, revenue requirement from capital associated with the wind repowering project is treated as a nominal cost when the results are extrapolated out through 2050.

PROJECT-BY-PROJECT ANALYSIS

Q. Did the Company provide updated economic analysis for each individual wind repowering project?

A. Yes. The methodology used to develop the project-by-project analysis is similar to the methodology used to perform the economic analysis for the proposed wind repowering project. The Company ran one SO model simulation that included the full scope of the wind repowering project and then 12 separate SO model simulations where one of the repowered wind facilities is assumed to be excluded from the scope of the wind repowering project. The total system cost from the SO model simulation where all facilities are repowered and from the SO model simulation where one facility is removed from scope is used to calculate the marginal PVRR(d) for each wind facility.

Using the resource portfolios from the SO model simulations, this same approach was used to calculate PVRR(d) for each wind facility using projected system costs from PaR over a 20-year forecast period. Finally, the SO model and PaR results are used to estimate the change in nominal annual revenue requirement for each wind facility by extending the system modeling results to 2050. The methodology used to estimate the change in nominal annual revenue requirement through 2050 is identical to the methodology used to analyze the full scope of the wind repowering project.

Q. What price-policy scenarios were used in the project-by-project analysis?

A. The Company used two price-policy scenarios—the low natural gas and zero CO_2 price-policy scenario and the medium natural gas and medium CO_2 price-policy scenario. Based on the results of these two price-policy scenarios, the Company determined which individual projects provided net customer benefits under the updated assumptions described above.

Q. Please summarize the project-by-project PVRR(d) results calculated from the SO model and PaR through 2036 when assuming medium natural gas and medium CO_2 price-policy assumptions.

A. Table 1-SD summarizes the PVRR(d) results for each wind facility within the scope of the wind repowering project. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and for PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When applying medium natural gas and medium CO_2 price-policy assumptions, benefits from repowering the Leaning Juniper wind facility are equal to costs. All other wind facilities are projected to deliver net benefits.

Table 1-SD. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Medium Natural Gas and Medium CO_2 Price-Policy Assumptions ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($25)	($21)	($23)
Glenrock 3	($8)	($7)	($7)
Seven Mile Hill 1	($33)	($28)	($29)
Seven Mile Hill 2	($7)	($7)	($7)
High Plains	($17)	($13)	($13)
McFadden Ridge	($5)	($4)	($4)
Dunlap Ranch	($30)	($26)	($27)
Rolling Hills	($12)	($9)	($10)
Leaning Juniper	($0)	($0)	($0)
Marengo 1	($35)	($33)	($34)
Marengo 2	($15)	($14)	($15)
Goodnoe Hills	($18)	($18)	($19)
Total	($205)	($180)	($189)

Q. Please summarize the project-by-project PVRR(d) results calculated from the SO model and PaR through 2036 when assuming low natural gas and zero CO_2 price-policy assumptions.

A. Table 2-SD summarizes the PVRR(d) results for each wind facility within the scope of the wind repowering project. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and for PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When applying low natural gas and zero CO_2 price-policy assumptions, costs from repowering the Leaning Juniper wind facility are slightly higher than the benefits. All other wind facilities are projected to deliver net benefits.

Table 2-SD. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Low Natural Gas and Zero CO_2 Price-Policy Assumptions ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($21)	($21)	($22)
Glenrock 3	($7)	($6)	($6)
Seven Mile Hill 1	($28)	($28)	($29)
Seven Mile Hill 2	($6)	($6)	($6)
High Plains	($12)	($9)	($10)
McFadden Ridge	($4)	($3)	($3)
Dunlap Ranch	($25)	($22)	($24)
Rolling Hills	($9)	($7)	($7)
Leaning Juniper	$6	$3	$4
Marengo 1	($27)	($25)	($26)
Marengo 2	($11)	($10)	($11)
Goodnoe Hills	($13)	($15)	($15)
Total	($157)	($149)	($156)

Q. Please summarize the project-by-project PVRR(d) results calculated from the change in annual revenue requirement through 2050.

A. Table 3-SD summarizes the PVRR(d) results for each wind facility calculated off of the change in annual nominal revenue requirement through 2050 for both price-policy scenarios. Unlike the results summarized in Table 4, these results account for the substantial increase in incremental energy beyond the 2036 time frame. Each of the wind facilities within the scope of the proposed repowering project show net benefits with repowering under the medium natural gas and medium CO_2 price-policy scenario and all facilities show net benefits under the low natural gas and zero CO_2 price-policy scenario, except for the Leaning Juniper wind facility, where the benefits are equal to the costs.

Table 3-SD. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Wind Facility	Medium Natural Gas and Medium CO_2	Low Natural Gas and Zero CO_2
Glenrock 1	($33)	($33)
Glenrock 3	($11)	($6)
Seven Mile Hill 1	($41)	($40)
Seven Mile Hill 2	($10)	($6)
High Plains	($22)	($6)
McFadden Ridge	($7)	($2)
Dunlap Ranch	($39)	($23)
Rolling Hills	($15)	($5)
Leaning Juniper	($8)	($0)
Marengo 1	($75)	($46)
Marengo 2	($20)	($7)
Goodnoe Hills	($26)	($19)
Total	($306)	($194)

Q. The project-by-project results vary by wind facility, and some wind facilities appear to show relatively small PVRR(d) benefits. Have you calculated the net benefits of the wind repowering project taking into account the size of each wind facility?

A. Yes. As described in my rebuttal testimony, the magnitude of the PVRR(d) results must be considered in relation to the specific attributes of the repowered wind facility, including the size of the facility, the expected cost to repower the facility, and the level of annual energy output expected after the new equipment is installed. For example, the PVRR(d) for McFadden Ridge shows a $7 million benefit when repowered (using medium natural gas and medium CO_2 price-policy assumptions)—the lowest PVRR(d) among all of the project-by-project results. The PVRR(d) benefit for McFadden Ridge is approximately 9 percent of the $75 million benefit for Marengo I, which yields the highest PVRR(d) among all of the project-by-project results. However, the current capacity of McFadden Ridge (28.5 MW) is approximately 20 percent of the current capacity of Marengo I (140.4 MW). Similarly, the expected energy output after repowering for McFadden Ridge (approximately 117 GWh per year) is approximately 24 percent of the expected energy output after repowering for Marengo I (approximately 488 GWh per year).

A reasonable metric to evaluate the relative benefits among the wind facilities that captures the specific attributes of each facility is the nominal levelized net benefit per incremental MWh expected after the facility is repowered. This metric captures the specific repowering cost for each facility net of the specific benefits of each facility per incremental MWh of energy expected after the facility is repowered. Table 4-SD shows the nominal levelized net benefit of repowering per MWh of expected incremental energy output after repowering for each wind facility. When using medium natural gas and medium CO_2 price-policy assumptions, the table shows the Seven Mile Hill II facility produces the largest net benefit per incremental MWh ($37/MWh), and Leaning Juniper produces the smallest net benefit per incremental MWh ($7/MWh).

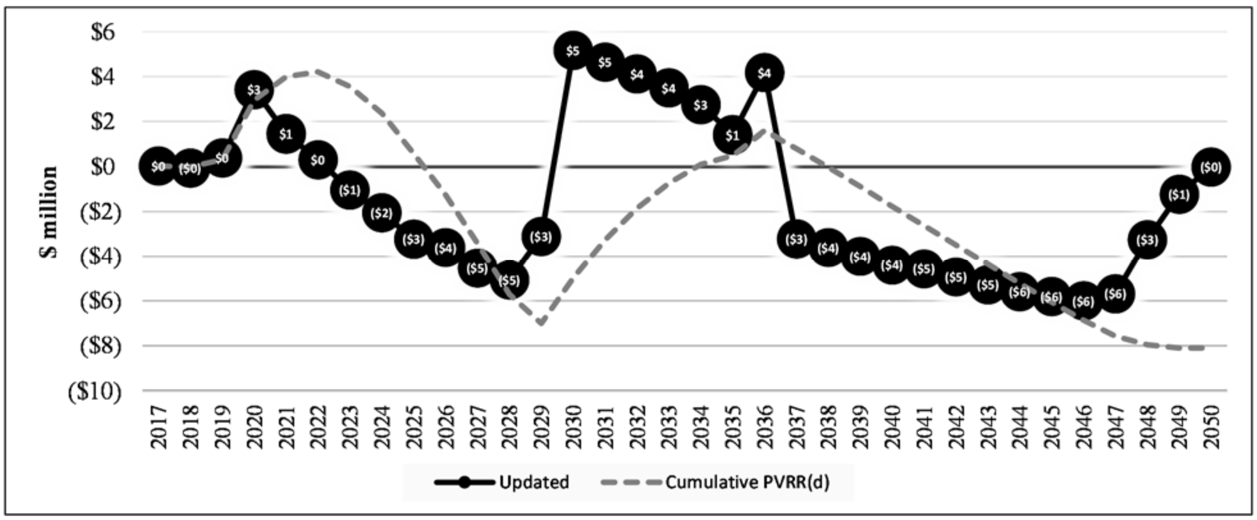
Table 4-SD. Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering ($/MWh)

Wind Facility	Medium Natural Gas and Medium CO_2	Low Natural Gas and Zero CO_2
Glenrock 1	$29/MWh	$29/MWh
Glenrock 3	$28/MWh	$16/MWh
Seven Mile Hill 1	$30/MWh	$29/MWh
Seven Mile Hill 2	$36/MWh	$23/MWh
High Plains	$17/MWh	$5/MWh
McFadden Ridge	$17/MWh	$5/MWh
Dunlap Ranch	$28/MWh	$17/MWh
Rolling Hills	$19/MWh	$7/MWh
Leaning Juniper	$7/MWh	$0/MWh
Marengo 1	$37/MWh	$23/MWh
Marengo 2	$21/MWh	$8/MWh
Goodnoe Hills	$26/MWh	$18/MWh
Weighted Average	$25/MWh	$16/MWh

Q. Have you reviewed the change in annual nominal revenue requirement due to wind repowering from the Leaning Juniper facility, which yields the lowest net benefits per MWh of incremental energy output among all facilities within the proposed scope of repowering project?

A. Yes. Figure 4-SD shows the change in nominal revenue requirement due to wind repowering for the Leaning Juniper wind facility when using medium natural gas and medium CO_2 price assumptions. The figure also shows the cumulative PVRR(d) for Leaning Juniper through 2050. The cumulative PVRR(d) for any given year reflects the present value net benefits from prior years that are associated with repowering Leaning Juniper. For instance, the cumulative PVRR(d) shown for 2020 represents the present value of the net benefits for repowering in each year over the period 2017 through 2020. Consequently, the cumulative PVRR(d) in 2050 captures the net benefits of repowering the Leaning Juniper wind facility through its expected useful life (*i.e.*, $8 million of net benefit as reported in Table 3-SD). This figure shows that repowering Leaning Juniper will produce customer benefits. Benefits are expected to exceed project costs in 20 years of the 30-year life of the repowered facility and federal PTCs contribute to customer benefits by 2023—three years after the new equipment is placed in service.

Figure 4-SD. Total-System Annual Revenue Requirement for Leaning Juniper with Wind Repowering ($ million)



Q. Is there an upside to the project-by-project PVRR(d) results?

A. Yes. Consistent with the economic analysis of the wind repowering project summarized in my direct and rebuttal testimony, the project-by-project results do not reflect the potential value of RECs that will be generated by the incremental energy output from each facility. For instance, as applied to the Leaning Juniper project discussed above, present-value net customer benefits would increase by approximately $1.1 million (approximately 14 percent of the PVRR(d) benefits under the medium natural gas and medium CO_2 price-policy scenario as shown in Table 3-SD) for every dollar assigned to the incremental RECs that will be generated from this facility. Importantly, there are counterparties that might be interested in procuring incremental RECs from repowered wind facilities such as Leaning Juniper, allowing realization of this upside value.

Q. Based on these results, has the Company decided against repowering any of the 12 facilities that were originally included in the repowering project?

A. No. The project-by-project analysis demonstrates that the proposed scope of the wind repowering project, which includes repowering 12 wind facilities with a current capacity totaling just over 999 MW is appropriate and will maximize customer benefits.

UPDATED SYSTEM MODELING PRICE-POLICY RESULTS

Q. Please summarize the updated PVRR(d) results for the full scope of the wind repowering project as calculated from the SO model and PaR through 2036 among all nine price-policy scenarios.

A. Table 5-SD summarizes the updated PVRR(d) results for each price-policy scenario for the full scope of the wind repowering project. The PVRR(d) between cases with and without the repowering project, are shown for the SO model and for PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-3SD).

Table 5-SD. Updated SO Model and PaR PVRR(d) (Benefit)/Cost of the Wind Repowering Projects ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($159)	($141)	($148)
Low Gas, Medium CO_2	($158)	($139)	($146)
Low Gas, High CO_2	($183)	($165)	($173)
Medium Gas, Zero CO_2	($201)	($171)	($180)
Medium Gas, Medium CO_2	($204)	($180)	($189)
Medium Gas, High CO_2	($215)	($193)	($203)
High Gas, Zero CO_2	($257)	($234)	($246)
High Gas, Medium CO_2	($260)	($248)	($260)
High Gas, High CO_2	($273)	($240)	($252)

Over a 20-year period, the wind repowering project reduces customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) net benefits range between $180 million, when derived from PaR stochastic-mean results, and $204 million, when derived from SO model results. These benefits are higher than those summarized in my rebuttal testimony (between $115 million to $138 million). This change is influenced by the fact that the updated analysis reflects nominal federal PTC benefits, whereas the analysis summarized in my rebuttal testimony reflects levelized federal PTC benefits.

Q. What trends do you observe in the modeling results across the different price-policy scenarios?

A. Projected system net benefits increase with higher natural-gas price assumptions, and similarly, generally increase with higher CO_2 price assumptions. Conversely, system net benefits generally decline when low natural-gas prices and low CO_2 prices are assumed. This trend holds true when looking at the results from the two simulations used to calculate the PVRR(d) for all nine of the price-policy scenarios. Importantly, both models continue to show that the net benefits from the wind repowering project are robust across a range of price-policy assumptions.

Q. Did you update the potential upside to these PVRR(d) results associated with REC revenues?

A. Yes. Consistent with my direct and rebuttal testimony, the PVRR(d) results presented in Table 5-SD do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities. Accounting for the updated performance estimates discussed above, customer benefits for all price-policy scenarios would improve by approximately $6 million for every dollar assigned to the incremental RECs that will be generated from the repowered facilities through 2036 (the same figure as estimated in my rebuttal analysis). Quantifying the potential upside associated with incremental REC revenues is intended to simply communicate that the net benefits from the repowering project could improve if the incremental RECs can be monetized in the market.

Q. Is there additional upside to the net benefits shown in Table 5-SD?

A. Yes. The CO_2 price assumptions used in the updated economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

UPDATED REVENUE REQUIREMENT MODELING PRICE-POLICY RESULTS

Q. Did the Company update its revenue requirement modeling among different price-policy scenarios to reflect the modeling updates described above?

A. Yes. Using the same annual revenue requirement modeling methodology described in my direct and rebuttal testimony, the Company updated its forecast of the change in nominal annual revenue requirement due to the wind repowering project, incorporating the modeling updates described earlier in my testimony.

Q. Please summarize the updated PVRR(d) results calculated from the change in annual revenue requirement through 2050.

A. Table 6-SD summarizes the updated PVRR(d) results for each price-policy scenario calculated off of the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-4SD).

Table 6-SD. Updated Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Wind Repowering Project ($ million)

Price-Policy Scenario	Updated Annual Revenue Requirement PVRR(d)	Rebuttal Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($127)	($360)
Low Gas, Medium CO_2	($121)	($480)
Low Gas, High CO_2	($223)	($473)
Medium Gas, Zero CO_2	($224)	($483)
Medium Gas, Medium CO_2	($273)	($471)
Medium Gas, High CO_2	($321)	($534)
High Gas, Zero CO_2	($389)	($555)
High Gas, Medium CO_2	($386)	($635)
High Gas, High CO_2	($466)	($619)

When system costs and benefits from the wind repowering project are extended through 2050, covering the full depreciable life of the repowered wind facilities, the wind repowering project reduces customer costs in all nine price-policy scenarios. Customer benefits range from $121 million in the low natural gas and medium CO_2 price-policy scenario to $466 million in the high natural gas and high CO_2 price-policy scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits of the wind repowering project are $273 million. While changes in federal tax law have reduced net benefits relative to the economic analysis summarized in my rebuttal testimony, the wind repowering project continues to provide significant customer benefits in all price-policy scenarios, and the updated economic analysis reconfirms that upside benefits outweigh downside risks.

Q. Is there additional potential upside to these PVRR(d) results associated with REC revenues?

A. Yes. Consistent with my direct and rebuttal testimony, the PVRR(d) results presented in Table 6-SD do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities. Accounting for the updated performance, customer benefits for all price-policy scenarios would improve by approximately $12 million for every dollar assigned to the incremental RECs that will be generated from the Wind Projects through 2050 (down slightly from $13 million in my rebuttal analysis).

Q. Is there additional potential upside to these PVRR(d) results shown in Table 6-SD?

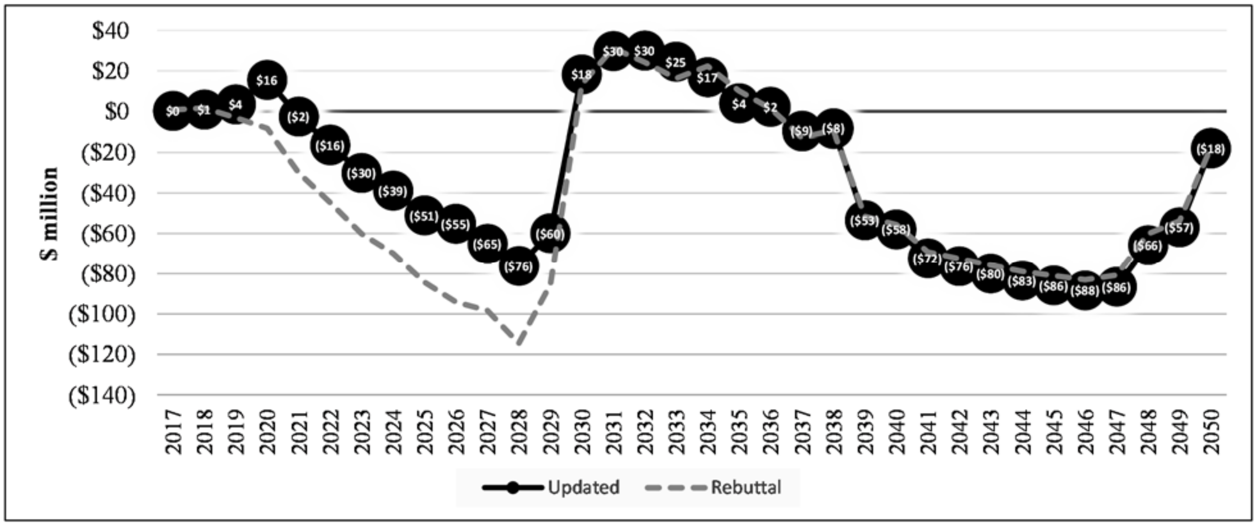
A. Yes. As noted earlier, the updated CO_2 price assumptions used in the updated economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars.

Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

Q. Please describe the change in annual nominal revenue requirement from the wind repowering project.

A. Figure 5-SD shows the updated change in nominal revenue requirement due to the wind repowering project for the medium natural gas, medium CO_2 price-policy scenario on a total-system basis. These results are shown alongside the same results from the economic analysis summarized in my rebuttal testimony. The change in nominal revenue requirement shown in the figure reflects updated costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against updated system impacts from the wind repowering project, reflecting the change in net power costs ("NPC"), emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the wind repowering project.

Figure 5-SD. Updated Total-System Annual Revenue Requirement With the Wind Repowering Project (Benefit)/Cost ($ million)



The data shown in this figure for the updated economic analysis have the same basic profile as the data from the economic analysis summarized in my rebuttal testimony. This profile also shows that the change in tax law has reduced net benefits through the first 10 years of operation, but that after the PTCs expire, net benefits track very closely with those presented in my rebuttal testimony. Despite a reduction in PTC benefits associated with changes in federal tax law, the wind repowering project continues to generate substantial near-term customer benefits and continues to contribute to customer benefits over the long-term.

Q. Did you evaluate how wind repowering benefits assumed beyond 2036 affect the PVRR(d) results calculated from the change in annual nominal revenue requirement through 2050?

A. Yes. As stated in my rebuttal testimony, the point of extrapolating results beyond 2036 is to capture the benefits from the significant increase in the expected annual energy output from the repowered wind facilities beyond the period in which the existing wind facilities would have otherwise reached the end of their lives. While the methodology used in my analysis is valid, the value of this incremental energy can be evaluated in different ways.

Table 7-SD summarizes how the PVRR(d) results through 2050 would change if flat market prices at the Palo Verde ("PV") market from the December 29, 2017 OFPC were used as the basis to evaluate the value of incremental energy from wind repowering over the 2037 to 2050 time frame. Recognizing there is both upside and downside price risk to the value of this energy, I assume different levels of PV prices—70 percent of the PV forward curve, 100 percent of the PV forward curve, and 130 percent of the PV forward curve. PacifiCorp's December 29, 2017 OFPC includes forward prices through 2042. Conservatively, I assume no escalation in PV prices beyond 2042 for each of these scenarios. Each of these scenarios is shown alongside the $273 million PVRR(d) net benefit when incremental energy from repowering beyond 2036 is calculated from system modeling results over the 2028 through 2036 time frame.

Table 7-SD. Updated Long-Term Benefit Sensitivity

Source of 2037-2050 Benefits	Nominal Levelized Benefit from 2037-2050 ($/MWh)	Annual Revenue Requirement PVRR(d) (Benefit)/Cost ($ million)
2027-2036 System Modeling	$59.08	($273)
70% of PV	$49.49	($213)
100% of PV	$70.70	($351)
130% of PV	$91.92	($489)

This analysis demonstrates that regardless of the methodology used to extend wind repowering benefits to 2050, the PVRR(d) result shows significant customer savings. If the incremental energy is valued at the PV forward curve, the PVRR(d) benefits of the wind repowering project are $351 million, which is $78 million higher than the methodology used in my analysis.

NEW WIND SENSITIVITY

Q. Has the Company updated its sensitivity analysis related to the new wind and transmission resources ("Combined Projects") that are the subject of Docket No. 17-035-40?

A. Yes. Based on the updates discussed above, coupled with the updated cost-and performance-estimates for the new wind resources and transmission proposed and described as the "Combined Projects" in Docket No. 17-035-40, the Company performed a sensitivity that includes the wind repowering project with the Combined Projects.

Q. What are the results of the Combined Projects sensitivity?

A. Table 8-SD summarizes PVRR(d) results for the Combined Projects sensitivity. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the base repowering study presented above in which wind repowering was evaluated without the Combined Projects.

Table 8-SD Combined Projects Sensitivity (Benefit)/Cost ($ million)

	Sensitivity (Repowering + Combined Projects) PVRR(d)	Base Study (Repowering) PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO_2			
SO Model	($532)	($204)	($328)
PaR Stochastic Mean	($466)	($180)	($286)
PaR Risk Adjusted	($489)	($189)	($300)
Low Gas, Zero CO_2			
SO Model	($301)	($159)	($142)
PaR Stochastic Mean	($300)	($141)	($159)
PaR Risk Adjusted	($315)	($148)	($167)

Customer benefits increase significantly when the wind repowering project is implemented with the Combined Projects in both the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. These results demonstrate that customer benefits not only persist, but increase, if both the wind repowering project and the Combined Projects are completed.

Q. Did you update the sensitivity that evaluates the potential incremental benefits of the wind repowering project if existing interconnection agreements, beyond what has already been assumed for the Marengo I and II facilities, can be modified to accommodate additional energy production?

A. No. The Company will continue to evaluate the feasibility and incremental benefits associated with modifications to existing interconnection agreements. If this ongoing review indicates that modifications to these interconnection agreements are feasible and provide net customer benefits, the Company will pursue those opportunities outside of this proceeding.

Q. Please summarize the conclusion of your supplemental direct testimony.

A. The updated economic analysis summarized in my supplemental direct testimony supports repowering just over 999 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington. The updated economic analysis shows significant net customer benefits in all of the scenarios analyzed. The wind repowering project will replace equipment at existing wind facilities with modern technology to improve efficiency, increase energy production, extend the operational life, reduce run-rate operating costs, reduce net power costs, and deliver substantial federal PTC benefits that will be passed on to customers. The proposed wind repowering project is in the public interest.

Q. Does this conclude your supplemental direct testimony?

A. Yes.

REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-1SD)
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Direct Testimony of Rick T. Link

Summary of the Cost and Performance Assumptions for the Wind Repowering Projects

February 2018

[redacted]

Existing Wind Prior to Repowering

	Capacity (MW)	LGIA Limited Capacity (MW)	Energy (MWh)	Capacity Factor	Repower Capital Investment ($m)	Date PTC Ends	End-of-Life Date	Repower Date
Glenrock 1	99.0	99.0	303,723	35.0%	n/a	12/30/2018	12/31/2038	n/a
Glenrock 3	39.0	39.0	113,438	33.2%	n/a	1/16/2019	12/31/2038	n/a
Seven Mile Hill 1	99.0	99.0	339,195	39.1%	n/a	12/30/2018	12/31/2038	n/a
Seven Mile Hill 2	19.5	19.5	71,224	41.7%	n/a	12/30/2018	12/31/2038	n/a
High Plains	99.0	99.0	306,145	35.3%	n/a	9/12/2019	12/31/2038	n/a
McFadden Ridge	28.5	28.5	93,101	37.3%	n/a	9/28/2019	12/31/2038	n/a
Dunlap Ranch	111.0	111.0	389,045	40.0%	n/a	9/30/2020	10/1/2040	n/a
Rolling Hills	99.0	99.0	271,635	31.3%	n/a	1/16/2019	12/31/2038	n/a
Leaning Juniper	100.5	100.5	233,592	26.5%	n/a	9/13/2016	9/14/2036	n/a
Marengo 1	140.4	140.4	360,279	29.3%	n/a	8/2/2017	8/1/2037	n/a
Marengo 2	70.2	70.2	166,742	27.1%	n/a	6/25/2018	6/1/2038	n/a
Goodnoe Hills	94.0	94.0	220,898	26.8%	n/a	5/31/2018	12/31/2038	n/a
Total	999.1	999.1	2,869,016	32.8%				

Repowered Wind

	Capacity (MW)	LGIA Limited Capacity[1] (MW)	LGIA Limited Energy (MWh)	LGIA Limited Capacity Factor	Repower Capital Investment ($m)	Date PTC Ends	End-of-Life Date	Repower Date
Glenrock 1	112.0	99.0	369,723	42.6%	[redacted]	9/30/2029	10/1/2049	10/1/2019
Glenrock 3	44.3	39.0	136,864	40.1%		9/30/2029	10/1/2049	10/1/2019
Seven Mile Hill 1	110.9	99.0	417,258	48.1%		6/30/2029	7/1/2049	7/1/2019
Seven Mile Hill 2	22.8	19.5	87,480	51.2%		6/30/2029	7/1/2049	7/1/2019
High Plains	115.5	99.0	382,400	44.1%		10/31/2029	11/1/2049	11/1/2019
McFadden Ridge	33.3	28.5	116,644	46.7%		10/31/2029	11/1/2049	11/1/2019
Dunlap Ranch	129.5	111.0	476,749	49.0%		11/30/2030	12/1/2050	12/1/2020
Rolling Hills	107.5	99.0	319,022	36.8%		9/30/2029	10/1/2049	10/1/2019
Leaning Juniper	110.6	100.5	296,590	33.7%		9/30/2029	10/1/2049	10/1/2019
Marengo 1	156.0	156.0	488,207	35.7%		10/31/2029	11/1/2049	11/1/2019
Marengo 2	78.0	78.0	232,424	34.0%		10/31/2029	11/1/2049	11/1/2019
Goodnoe Hills	103.4	94.0	283,696	34.5%		9/30/2029	10/1/2049	10/1/2019
Total	1,123.6	1,022.5	3,607,057	40.3%	$1,101			

[1] Marengo 1 and 2 include increased interconnection capability based on the completion of recent transmission studies.

[redacted]

Run-Rate Capital

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
All Repowered Projects	($9.8)	($14.7)	($19.6)	($20.5)	($19.8)	($18.0)	($17.9)	($15.2)	($13.2)	($11.4)	($9.6)	($9.9)

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
All Repowered Projects	($8.7)	($4.4)	($2.3)	($1.8)	($1.8)	($1.8)	($1.9)	($1.0)	$1.0	$9.2	$16.5	$17.0

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
All Repowered Projects	$18.6	$19.0	$19.4	$19.9	$20.3	$20.8	$21.3	$21.8	$12.5	$1.4

Run-Rate Operations and Maintenance Expense

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
All Repowered Projects	$0.0	$0.0	$3.9	$12.1	$12.8	$9.6	$9.5	$9.4	$9.2	$9.1	$9.0	$8.8

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
All Repowered Projects	$5.9	$2.2	$1.2	$1.2	$1.2	$1.2	$1.3	$2.1	$5.5	$13.7	$28.2	$29.5

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
All Repowered Projects	$32.3	$33.1	$33.8	$34.6	$35.4	$36.2	$37.1	$37.9	$29.9	$2.6

REDACTED
Rocky Mountain Power
Exhibit RMP___(RTL-2SD)
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Exhibit Accompanying Supplemental Direct Testimony of Rick T. Link

Nominal Henry Hub Natural-Gas Price Forecasts ($/MMBtu)

February 2018

THIS EXHIBIT IS CONFIDENTIAL IN ITS ENTIRETY AND IS PROVIDED UNDER SEPARATE COVER

Rocky Mountain Power
Exhibit RMP___(RTL-3SD)
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct Testimony of Rick T. Link

SO Model and PaR Model Annual Results ($ million) through 2036

February 2018

SO Model Annual Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($155)	$1	$3	$1	($13)	($16)	($16)	($17)	($18)	($18)	($19)	($20)	($22)	($23)	($25)	($25)	($25)	($26)	($27)	($28)	($28)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($5)	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
Change in System Fixed Cost	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	$0	($0)	$0	$0	$0
Net (Benefit)/Cost	($159)	$58	$62	$37	($51)	($73)	($72)	($76)	($75)	($79)	($78)	($82)	($83)	($56)	$34	$53	$54	$55	$56	$57	$59

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($145)	$1	$3	$1	($13)	($16)	($16)	($17)	($18)	($19)	($19)	($20)	($23)	($23)	($26)	($25)	($26)	($26)	($28)	($5)	$3
Change in Emissions	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($2)	($2)	($1)	$2	$2
Change in DSM	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)
Change in System Fixed Cost	($12)	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($15)	($28)
Net (Benefit)/Cost	($158)	$58	$62	$37	($51)	($73)	($72)	($76)	($75)	($79)	($78)	($82)	($83)	($56)	$32	$52	$53	$53	$54	$66	$62

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($166)	$1	$3	$1	($13)	($16)	($16)	($17)	($17)	($18)	($19)	($20)	($24)	($27)	($28)	($29)	($28)	($29)	($31)	($31)	($30)
Change in Emissions	($17)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($2)	($3)	($4)	($5)	($6)	($5)	($4)	($5)	($8)
Change in DSM	($9)	$0	$0	$0	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)
Change in System Fixed Cost	$7	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	$3	$3	$3	$3	$2	$2	$2	$4
Net (Benefit)/Cost	($183)	$58	$62	$37	($51)	($73)	($72)	($76)	($76)	($80)	($81)	($86)	($88)	($61)	$27	$46	$47	$48	$49	$50	$52

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($210)	$1	$3	$1	($13)	($17)	($18)	($18)	($20)	($22)	($22)	($23)	($26)	($29)	($32)	($34)	($42)	($46)	($48)	($50)	($60)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($12)	$0	$0	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
Change in System Fixed Cost	$20	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	$0	$0	$0	$0	$13	$10	$11	$11	$20
Net (Benefit)/Cost	($201)	$58	$62	$37	($52)	($75)	($75)	($78)	($79)	($84)	($83)	($87)	($88)	($63)	$26	$43	$49	$45	$44	$45	$45

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($185)	$1	$3	$1	($14)	($18)	($18)	($19)	($21)	($23)	($23)	($24)	($26)	($30)	($34)	($36)	($48)	($36)	($24)	($14)	($15)
Change in Emissions	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($6)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
Change in System Fixed Cost	($14)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	$0	$0	$0	$1	$1	$1	$16	($2)	($16)	($28)	($28)
Net (Benefit)/Cost	($204)	$58	$62	$37	($52)	($75)	($74)	($78)	($78)	($84)	($82)	($87)	($88)	($63)	$24	$42	$46	$43	$43	$43	$43

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($215)	$1	$3	$1	($13)	($17)	($18)	($19)	($20)	($23)	($23)	($26)	($28)	($39)	($49)	($53)	($56)	($36)	($35)	($29)	($29)
Change in Emissions	($11)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($2)	($3)	($7)	($4)	($2)	($2)	($0)	($3)	($2)	($2)
Change in DSM	($8)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($1)	($2)	($1)	($1)
Change in System Fixed Cost	$19	($0)	($0)	$0	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	$18	$19	$20	$22	($4)	($3)	($15)	($18)
Net (Benefit)/Cost	($215)	$58	$62	$37	($52)	($75)	($74)	($78)	($78)	($84)	($84)	($91)	($93)	($62)	$23	$42	$42	$40	$41	$38	$37

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($141)	$1	$4	$1	($19)	($21)	($23)	($8)	($9)	($10)	($10)	($11)	($11)	($12)	($16)	($15)	($17)	($41)	($41)	($42)	($39)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	$2	$0	$0	$0	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	$0	$0	$1	$1	$1	$1	$1	$1
Change in System Fixed Cost	($119)	($0)	($0)	$0	($0)	($0)	$0	($23)	($24)	($24)	($25)	($25)	($26)	($25)	($23)	($25)	($24)	($1)	($3)	($3)	($8)
Net (Benefit)/Cost	($257)	$58	$63	$37	($57)	($78)	($79)	($90)	($90)	($94)	($93)	($97)	($97)	($69)	$20	$39	$40	$41	$41	$41	$41

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($46)	$1	$4	$1	($19)	($21)	($23)	$9	$10	$11	$10	$11	$12	$12	$3	$3	$1	($30)	($41)	($42)	($51)
Change in Emissions	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)
Change in DSM	($14)	$0	$0	$0	$0	$0	($0)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($3)	($3)	($4)	($4)	($5)	($6)
Change in System Fixed Cost	($200)	($0)	($0)	$0	($0)	($0)	$0	($44)	($45)	($46)	($47)	($48)	($49)	($44)	($35)	($35)	($33)	($3)	$5	$5	$11
Net (Benefit)/Cost	($260)	$58	$63	$37	($57)	($78)	($79)	($95)	($94)	($97)	($97)	($101)	($99)	($66)	$24	$44	$46	$44	$43	$42	$40

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($230)	$1	$4	$1	($19)	($20)	($22)	($21)	($23)	($25)	($26)	($27)	($30)	($33)	($34)	($43)	($31)	($16)	($58)	($64)	($63)
Change in Emissions	($8)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($2)	($2)	($3)	($1)	($2)	($1)	($5)	($2)	($2)
Change in DSM	($3)	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)
Change in System Fixed Cost	($34)	($0)	($0)	$0	($0)	($1)	($1)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($12)	($27)	($11)	$13	$8
Net (Benefit)/Cost	($273)	$58	$63	$37	($57)	($78)	($79)	($85)	($85)	($91)	($90)	($96)	($98)	($74)	$15	$28	$34	$36	$9	$31	$30

PaR Stochastic-Mean Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($134)	$1	$2	$1	($10)	($12)	($13)	($13)	($14)	($14)	($15)	($15)	($21)	($22)	($23)	($23)	($24)	($24)	($25)	($26)	($26)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($5)	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
Change in Deficiency	($2)	$0	$0	($0)	($0)	$0	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($0)	($1)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	$0	($0)	$0	$0	$0
Net (Benefit)/Cost	($141)	$58	$61	$36	($49)	($70)	($69)	($73)	($72)	($76)	($75)	($78)	($82)	($55)	$35	$54	$55	$56	$57	$58	$59

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($122)	$1	$2	$1	($10)	($12)	($13)	($14)	($14)	($15)	($15)	($16)	($21)	($22)	($23)	($23)	($24)	($24)	($24)	($4)	$4
Change in Emissions	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($2)	($2)	($2)	$1	$2
Change in VOM	($1)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	$0	$1
Change in DSM	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($3)	($3)
Change in Deficiency	($1)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	($0)	$0	$0	($0)	($0)	($1)	($0)	($1)	($1)	$3	($0)	($4)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($12)	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($15)	($28)
Net (Benefit)/Cost	($139)	$58	$61	$37	($49)	($69)	($69)	($73)	($72)	($75)	($74)	($78)	($82)	($55)	$34	$53	$53	$54	$59	$66	$59

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88

Change in NPC	($145)	$1	$2	$1	($10)	($12)	($12)	($13)	($14)	($14)	($15)	($16)	($23)	($25)	($27)	($27)	($27)	($27)	($28)	($29)	($30)
Change in Emissions	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($3)	($4)	($5)	($5)	($6)	($6)	($6)	($6)	($6)
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($9)	$0	$0	$0	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)
Change in Deficiency	($0)	$0	$0	($0)	($0)	($0)	$0	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	($2)	($1)	($1)	$5	$0	($1)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	$7	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	$3	$3	$3	$3	$2	$2	$2	$4
Net (Benefit)/Cost	($165)	$58	$61	$37	($49)	($69)	($69)	($73)	($72)	($76)	($77)	($83)	($88)	($61)	$27	$45	$48	$49	$55	$51	$52

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($174)	$1	$2	$1	($11)	($13)	($14)	($14)	($16)	($17)	($17)	($18)	($25)	($27)	($27)	($29)	($37)	($38)	($40)	($43)	($50)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($2)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)
Change in DSM	($13)	$0	$0	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
Change in Deficiency	($2)	($0)	$0	$0	($0)	($0)	$0	($0)	$0	($0)	$0	($0)	$0	($0)	($0)	($1)	($2)	($0)	($3)	$0	($1)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	$20	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	$0	$0	$0	$0	$13	$10	$11	$11	$20
Net (Benefit)/Cost	($171)	$58	$62	$36	($50)	($71)	($71)	($75)	($74)	($79)	($78)	($82)	($87)	($62)	$29	$47	$51	$51	$48	$51	$54

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($159)	$1	$2	$1	($11)	($14)	($14)	($15)	($16)	($18)	($18)	($18)	($26)	($28)	($31)	($33)	($43)	($33)	($22)	($15)	($15)
Change in Emissions	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($0)	$0	$0
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($6)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
Change in Deficiency	$1	($0)	$0	$0	($0)	$0	$0	($0)	$0	($0)	$0	$0	($0)	($0)	($1)	($1)	($2)	$3	$2	($0)	$1
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($14)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	$0	$0	$0	$1	$1	$1	$16	($2)	($16)	($28)	($28)
Net (Benefit)/Cost	($180)	$58	$62	$37	($49)	($71)	($70)	($74)	($74)	($79)	($77)	($82)	($88)	($62)	$25	$43	$48	$48	$46	$41	$44

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($186)	$1	$2	$1	($11)	($13)	($14)	($15)	($16)	($18)	($18)	($19)	($27)	($39)	($45)	($47)	($49)	($32)	($33)	($28)	($27)
Change in Emissions	($16)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($3)	($6)	($6)	($5)	($6)	($4)	($4)	($3)	($3)
Change in VOM	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($8)	$0	$0	($1)	($1)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
Change in Deficiency	($2)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	$0	$0	($0)	($0)	($0)	($1)	($1)	($1)	($0)	($1)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	$19	($0)	($0)	$0	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	$18	$19	$20	$22	($4)	($3)	($15)	($18)
Net (Benefit)/Cost	($193)	$58	$61	$36	($50)	($71)	($70)	($74)	($74)	($79)	($79)	($85)	($92)	($61)	$25	$44	$44	$40	$40	$37	$37

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($116)	$1	$3	$1	($14)	($16)	($18)	($4)	($5)	($5)	($5)	($6)	($12)	($13)	($17)	($16)	($17)	($38)	($36)	($39)	($36)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($0)	$0	$0	$0	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)
Change in DSM	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$1	$1	$1	$1
Change in Deficiency	($2)	$0	$0	$0	$0	($0)	$0	($0)	$0	($0)	($0)	($0)	$0	$0	$0	$0	$0	($2)	($3)	($1)	($2)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($119)	($0)	($0)	$0	($0)	($0)	$0	($23)	($24)	($24)	($25)	($25)	($26)	($25)	($23)	($25)	($24)	($1)	($3)	($3)	($8)
Net (Benefit)/Cost	($234)	$58	$62	$37	($53)	($73)	($73)	($86)	($85)	($89)	($89)	($92)	($98)	($70)	$20	$39	$40	$41	$42	$43	$42

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($33)	$1	$3	$1	($14)	($16)	($18)	$11	$12	$12	$12	$12	$8	$8	$1	$0	($1)	($28)	($36)	($38)	($44)
Change in Emissions	($1)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$1	($1)	($1)	($1)	($2)
Change in VOM	$1	$0	$0	$0	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)
Change in DSM	($15)	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($3)	($3)	($3)	($4)	($4)	($6)	($6)
Change in Deficiency	($1)	$0	$0	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	($0)	$0	$0	$1	$1	$0	($2)	($2)	($1)	($1)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($200)	($0)	($0)	$0	($0)	($0)	$0	($44)	($45)	($46)	($47)	($48)	($49)	($44)	($35)	($35)	($33)	($3)	$5	$5	$11
Net (Benefit)/Cost	($248)	$58	$62	$37	($53)	($73)	($73)	($93)	($92)	($95)	($95)	($100)	($103)	($70)	$23	$43	$44	$44	$44	$45	$46

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$1	$57	$59	$36	($38)	($57)	($56)	($59)	($57)	($60)	($59)	($62)	($60)	($33)	$59	$78	$80	$82	$84	$86	$88
Change in NPC	($191)	$1	$3	$1	($14)	($16)	($17)	($16)	($17)	($18)	($19)	($19)	($28)	($30)	($32)	($43)	($29)	($22)	($49)	($52)	($51)
Change in Emissions	($11)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($2)	($3)	($3)	($1)	($2)	($2)	($6)	($4)	($4)
Change in VOM	($2)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($0)	($0)	($1)	($0)	($0)
Change in DSM	($3)	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)
Change in Deficiency	($0)	$0	$0	$0	$0	($0)	$0	($0)	$0	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($3)	$9	($2)	($3)
Change in PTC losses (dumped energy)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in System Fixed Cost	($34)	($0)	($0)	$0	($0)	($1)	($1)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($12)	($27)	($11)	$13	$8
Net (Benefit)/Cost	($240)	$58	$62	$37	($53)	($74)	($73)	($80)	($79)	($83)	($84)	($89)	($96)	($71)	$16	$27	$35	$27	$24	$38	$36

Rocky Mountain Power
Exhibit RMP___(RTL-4SD)
Docket No. 17-035-39
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct Testimony of Rick T. Link

Estimated Annual Revenue Requirement Results ($ million) through 2050

February 2018

Exhibit RMP__(RTL-R3)

Estimated Annual Revenue Requirement Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($394)	$1	$2	$1	($10)	($12)	($13)	($13)	($14)	($14)	($15)	($15)	($21)	($22)	($23)	($23)	($24)	($24)	($25)	($26)	($26)	($46)	($64)	($116)	($121)	($135)	($138)	($141)	($144)	($147)	($150)	($154)	($144)	($97)	($15)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($24)	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($1)	($2)	($3)	($4)	($7)	($7)	($8)	($8)	($9)	($9)	($9)	($9)	($9)	($9)	($6)	($1)
System Fixed Costs	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net System Impacts	($418)	$1	$2	$1	($11)	($13)	($13)	($14)	($15)	($15)	($16)	($16)	($22)	($22)	($24)	($25)	($26)	($26)	($27)	($27)	($28)	($49)	($68)	($123)	($128)	($143)	($146)	($149)	($153)	($156)	($159)	($163)	($152)	($103)	($16)
2050 Net (Benefit)/Cost	($127)	$0	$1	$3	$16	($1)	($15)	($29)	($37)	($47)	($52)	($61)	($70)	($53)	$27	$41	$37	$33	$28	$21	$18	$10	$18	($6)	($8)	($17)	($19)	($22)	($24)	($25)	($26)	($23)	($7)	($17)	($12)

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($334)	$1	$2	$1	($10)	($12)	($13)	($14)	($14)	($15)	($15)	($16)	($21)	($22)	($23)	($23)	($24)	($24)	($24)	($4)	$4	($38)	($52)	($94)	($98)	($110)	($112)	($114)	($117)	($120)	($122)	($125)	($117)	($79)	($13)
Emissions	($9)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($2)	($2)	($2)	$1	$2	($1)	($2)	($3)	($3)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($3)	($0)
Other Variable Costs	($15)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($2)	($1)	$3	($3)	($6)	($2)	($3)	($5)	($5)	($6)	($6)	($6)	($6)	($7)	($7)	($7)	($6)	($4)	($1)
System Fixed Costs	($55)	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($1)	($15)	($28)	($8)	($11)	($19)	($20)	($22)	($23)	($23)	($24)	($24)	($25)	($25)	($24)	($16)	($3)
Net System Impacts	($413)	$1	$2	$1	($10)	($12)	($13)	($14)	($14)	($15)	($15)	($16)	($21)	($22)	($25)	($26)	($27)	($28)	($25)	($20)	($29)	($49)	($67)	($122)	($127)	($141)	($145)	($148)	($151)	($154)	($158)	($161)	($151)	($102)	($16)
2050 Net (Benefit)/Cost	($121)	$0	$1	$3	$16	($1)	($15)	($28)	($36)	($47)	($52)	($61)	($70)	($53)	$27	$40	$35	$30	$30	$29	$18	$10	$19	($4)	($7)	($15)	($18)	($20)	($22)	($24)	($25)	($21)	($5)	($16)	($11)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($443)	$1	$2	$1	($10)	($12)	($12)	($13)	($14)	($14)	($15)	($16)	($23)	($25)	($27)	($27)	($27)	($27)	($28)	($29)	($30)	($53)	($74)	($133)	($138)	($154)	($158)	($161)	($165)	($168)	($172)	($176)	($164)	($111)	($18)
Emissions	($73)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($3)	($4)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($10)	($14)	($24)	($25)	($28)	($29)	($30)	($30)	($31)	($32)	($32)	($30)	($20)	($3)
Other Variable Costs	($31)	$0	$0	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($3)	($2)	($3)	$2	($2)	($4)	($4)	($5)	($9)	($10)	($11)	($11)	($11)	($11)	($12)	($12)	($12)	($11)	($8)	($1)
System Fixed Costs	$33	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)	$0	$0	($0)	$3	$3	$3	$3	$2	$2	$2	$4	$5	$6	$11	$12	$13	$14	$14	$14	$14	$15	$15	$14	$10	$2
Net System Impacts	($514)	$1	$2	$1	($10)	($12)	($14)	($15)	($15)	($16)	($18)	($21)	($27)	($28)	($31)	($33)	($32)	($33)	($29)	($34)	($36)	($62)	($86)	($155)	($161)	($180)	($184)	($188)	($192)	($197)	($201)	($206)	($192)	($130)	($21)
2050 Net (Benefit)/Cost	($223)	$0	$1	$3	$16	($1)	($15)	($29)	($37)	($48)	($55)	($66)	($76)	($59)	$20	$32	$30	$25	$26	$14	$11	($3)	$0	($38)	($42)	($54)	($58)	($61)	($64)	($66)	($68)	($66)	($46)	($44)	($16)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($552)	$1	$2	$1	($11)	($13)	($14)	($14)	($16)	($17)	($17)	($18)	($25)	($27)	($27)	($29)	($37)	($38)	($40)	($43)	($50)	($67)	($93)	($168)	($175)	($195)	($200)	($204)	($209)	($213)	($218)	($223)	($208)	($140)	($22)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($55)	$0	$0	($0)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($4)	($5)	($3)	($6)	($3)	($4)	($7)	($9)	($17)	($17)	($19)	($20)	($20)	($21)	($21)	($22)	($22)	($21)	($14)	($2)
System Fixed Costs	$91	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	$0	$0	$0	$0	$13	$10	$11	$11	$20	$13	$18	$32	$33	$37	$38	$38	$39	$40	$41	$42	$39	$26	$4
Net System Impacts	($516)	$1	$2	$1	($11)	($14)	($15)	($16)	($17)	($19)	($19)	($20)	($27)	($29)	($30)	($32)	($29)	($30)	($35)	($35)	($34)	($61)	($85)	($153)	($159)	($178)	($182)	($186)	($190)	($194)	($198)	($203)	($189)	($128)	($20)
2050 Net (Benefit)/Cost	($224)	$0	$1	$3	$15	($3)	($17)	($31)	($39)	($51)	($56)	($65)	($76)	($60)	$22	$34	$34	$28	$19	$13	$12	($2)	$2	($36)	($40)	($52)	($55)	($58)	($61)	($63)	($65)	($63)	($44)	($42)	($16)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($470)	$1	$2	$1	($11)	($14)	($14)	($15)	($16)	($18)	($18)	($18)	($26)	($28)	($31)	($33)	($43)	($33)	($22)	($15)	($15)	($55)	($77)	($139)	($144)	($161)	($165)	($168)	($172)	($176)	($180)	($184)	($171)	($116)	($18)
Emissions	($6)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($0)	$0	$0	($1)	($1)	($2)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($3)	($2)	($0)
Other Variable Costs	($24)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($2)	($2)	($2)	($2)	($2)	($4)	$2	($0)	($2)	($0)	($3)	($4)	($8)	($8)	($9)	($9)	($9)	($9)	($10)	($10)	($10)	($9)	($6)	($1)
System Fixed Costs	($65)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	$0	$0	$0	$1	$1	$1	$16	($2)	($16)	($28)	($28)	($9)	($12)	($23)	($23)	($26)	($27)	($27)	($28)	($29)	($29)	($30)	($28)	($19)	($3)
Net System Impacts	($565)	$1	$2	$1	($11)	($14)	($15)	($15)	($17)	($19)	($19)	($20)	($27)	($29)	($33)	($36)	($32)	($34)	($38)	($44)	($44)	($68)	($95)	($171)	($178)	($198)	($203)	($207)	($212)	($217)	($221)	($226)	($211)	($143)	($23)
2050 Net (Benefit)/Cost	($273)	$0	$1	$4	$16	($2)	($16)	($30)	($39)	($51)	($55)	($65)	($76)	($60)	$18	$30	$30	$25	$17	$4	$2	($9)	($8)	($53)	($58)	($72)	($76)	($80)	($83)	($86)	($88)	($86)	($66)	($57)	($18)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3

Exhibit RMP__(RTL-R3)

Estimated Annual Revenue Requirement Results ($ million)

Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($596)	$1	$2	$1	($11)	($13)	($14)	($15)	($16)	($18)	($18)	($19)	($27)	($39)	($45)	($47)	($49)	($32)	($33)	($28)	($27)	($73)	($101)	($183)	($190)	($212)	($217)	($222)	($227)	($232)	($237)	($242)	($226)	($153)	($24)
Emissions	($64)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($3)	($6)	($6)	($5)	($6)	($4)	($4)	($3)	($3)	($9)	($12)	($22)	($22)	($25)	($26)	($26)	($27)	($27)	($28)	($29)	($27)	($18)	($3)
Other Variable Costs	($37)	$0	$0	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($2)	($3)	($5)	($6)	($12)	($12)	($13)	($14)	($14)	($14)	($15)	($15)	($15)	($14)	($10)	($2)
System Fixed Costs	$85	($0)	($0)	$0	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	$18	$19	$20	$22	($4)	($3)	($15)	($18)	$12	$16	$29	$31	$34	$35	$36	$37	$37	$38	$39	$36	$25	$4
Net System Impacts	($612)	$1	$2	$1	($11)	($14)	($15)	($16)	($17)	($19)	($21)	($23)	($32)	($29)	($33)	($34)	($36)	($42)	($43)	($48)	($51)	($74)	($103)	($186)	($194)	($216)	($221)	($226)	($231)	($236)	($241)	($247)	($231)	($156)	($25)
2050 Net (Benefit)/Cost	($321)	$0	$1	$3	$15	($3)	($17)	($30)	($39)	($51)	($57)	($68)	($81)	($59)	$18	$31	$27	$17	$11	$0	($5)	($16)	($17)	($69)	($74)	($90)	($95)	($99)	($102)	($105)	($108)	($107)	($85)	($70)	($20)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($374)	$1	$3	$1	($14)	($16)	($18)	($4)	($5)	($5)	($5)	($6)	($12)	($13)	($17)	($16)	($17)	($38)	($36)	($39)	($36)	($46)	($64)	($115)	($120)	($133)	($136)	($139)	($142)	($146)	($149)	($152)	($142)	($96)	($15)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($1)	$0	$0	$0	($0)	($0)	($0)	($0)	$0	$0	$0	$1	$1	$1	$1	$1	$1	($2)	($3)	($1)	($1)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($0)	($0)
System Fixed Costs	($306)	($0)	($0)	$0	($0)	($0)	$0	($23)	($24)	($24)	($25)	($25)	($26)	($25)	($23)	($25)	($24)	($1)	($3)	($3)	($8)	($33)	($46)	($83)	($87)	($97)	($99)	($101)	($103)	($106)	($108)	($110)	($103)	($70)	($11)
Net System Impacts	($681)	$1	$3	$1	($14)	($17)	($18)	($27)	($28)	($29)	($30)	($30)	($37)	($37)	($38)	($40)	($40)	($41)	($42)	($43)	($46)	($79)	($110)	($199)	($207)	($231)	($236)	($241)	($246)	($252)	($257)	($263)	($246)	($166)	($26)
2050 Net (Benefit)/Cost	($389)	$0	$1	$4	$12	($5)	($19)	($42)	($50)	($61)	($66)	($76)	($86)	($68)	$13	$26	$22	$18	$13	$6	$1	($21)	($24)	($81)	($87)	($105)	($109)	($114)	($118)	($121)	($124)	($123)	($100)	($80)	($22)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($157)	$1	$3	$1	($14)	($16)	($18)	$11	$12	$12	$12	$12	$8	$8	$1	$0	($1)	($28)	($36)	($38)	($44)	($22)	($31)	($55)	($58)	($64)	($66)	($67)	($69)	($70)	($72)	($73)	($69)	($46)	($7)
Emissions	($3)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$1	$1	($1)	($1)	($1)	($2)	($0)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($0)
Other Variable Costs	($56)	$0	$0	$0	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($1)	($1)	($3)	($6)	($7)	($8)	($7)	($7)	($10)	($18)	($19)	($21)	($22)	($22)	($23)	($23)	($24)	($24)	($23)	($15)	($2)
System Fixed Costs	($461)	($0)	($0)	$0	($0)	($0)	$0	($44)	($45)	($46)	($47)	($48)	($49)	($44)	($35)	($35)	($33)	($3)	$5	$5	$11	($46)	($64)	($116)	($121)	($135)	($138)	($141)	($144)	($148)	($151)	($154)	($144)	($97)	($16)
Net System Impacts	($677)	$1	$3	$1	($14)	($17)	($18)	($34)	($34)	($35)	($36)	($38)	($42)	($37)	($36)	($36)	($36)	($38)	($39)	($41)	($42)	($76)	($106)	($191)	($199)	($222)	($227)	($232)	($237)	($242)	($248)	($253)	($237)	($160)	($25)
2050 Net (Benefit)/Cost	($386)	$0	$1	$4	$12	($5)	($19)	($49)	($56)	($67)	($73)	($83)	($91)	($68)	$16	$30	$26	$21	$15	$7	$4	($18)	($20)	($74)	($79)	($96)	($100)	($105)	($109)	($112)	($115)	($113)	($91)	($74)	($21)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$873	($1)	($2)	$22	$114	$118	$108	$100	$92	$87	$83	$79	$75	$70	$66	$63	$60	$56	$52	$46	$43	$51	$70	$84	$85	$88	$88	$88	$88	$89	$91	$97	$102	$52	$2
O&M	$125	$0	$0	$4	$12	$13	$10	$9	$9	$9	$9	$9	$9	$6	$2	$1	$1	$1	$1	$1	$2	$6	$14	$28	$30	$32	$33	$34	$35	$35	$36	$37	$38	$30	$3
Wind Tax	$18	$0	($0)	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$5	$5	$6	$6	$6	$6	$6	$6	$6	$6	$4	$1
PTCs	($725)	$0	$1	($24)	($100)	($120)	($120)	($125)	($125)	($129)	($129)	($134)	($134)	($108)	($18)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$291	($1)	($1)	$3	$27	$11	($2)	($15)	($22)	($32)	($37)	($45)	($49)	($31)	$52	$65	$62	$59	$55	$48	$46	$59	$86	$117	$120	$126	$127	$127	$129	$131	$133	$140	$146	$86	$5
System Impacts																																			
NPC	($594)	$1	$3	$1	($14)	($16)	($17)	($16)	($17)	($18)	($19)	($19)	($28)	($30)	($32)	($43)	($29)	($22)	($49)	($52)	($51)	($72)	($99)	($180)	($187)	($209)	($213)	($218)	($223)	($228)	($233)	($238)	($222)	($150)	($24)
Emissions	($43)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($2)	($3)	($3)	($1)	($2)	($2)	($6)	($4)	($4)	($6)	($8)	($14)	($15)	($17)	($17)	($17)	($18)	($18)	($19)	($19)	($18)	($12)	($2)
Other Variable Costs	($16)	$0	$0	$0	($0)	($0)	($0)	($1)	($0)	($0)	($0)	($0)	($1)	($1)	($1)	($1)	($1)	($4)	$7	($4)	($5)	($2)	($3)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($7)	($7)	($6)	($4)	($1)
System Fixed Costs	($105)	($0)	($0)	$0	($0)	($1)	($1)	($5)	($5)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($12)	($27)	($11)	$13	$8	($13)	($17)	($31)	($33)	($36)	($37)	($38)	($39)	($40)	($41)	($42)	($39)	($26)	($4)
Net System Impacts	($758)	$1	$3	$1	($14)	($17)	($18)	($21)	($22)	($23)	($25)	($27)	($36)	($39)	($42)	($51)	($45)	($55)	($59)	($47)	($52)	($92)	($128)	($230)	($240)	($268)	($274)	($280)	($286)	($292)	($299)	($305)	($285)	($192)	($31)
2050 Net (Benefit)/Cost	($466)	$0	$1	$4	$12	($6)	($20)	($36)	($44)	($55)	($61)	($72)	($84)	($70)	$9	$14	$17	$4	($5)	$1	($5)	($33)	($41)	($113)	($120)	($142)	($147)	($152)	($157)	($161)	($166)	($165)	($139)	($107)	($26)

Rocky Mountain Power
Docket No. 17-035-39
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Supplemental Direct Testimony of Joelle R. Steward

February 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 and rebuttal testimonies of Mr. Jeffrey K. Larsen in this case?

A. Yes.

PURPOSE OF TESTIMONY

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

A. My testimony supports the Company's request for approval of its energy resource decision for wind repowering. I update the expected costs and benefits proposed to be recovered through the Resource Tracking Mechanism ("RTM"), to reflect the updated economic analysis presented by Company witness Mr. Rick T. Link. The Company updated its economic analysis for the effects of federal tax reform, as described by Company witness Ms. Nikki L. Kobliha. The updated analysis continues to show that the repowering project is beneficial to customers under all price-policy scenarios. My exhibits show, however, that federal tax reform, and in particular the corresponding decrease in the gross-up factor for production tax credits ("PTCs"), results in a lower value for PTCs, producing a net revenue requirement increase from 2019-2021, with rate benefits now starting in 2022. If the repowering project is reflected in rates through the RTM for 2019–2021, however, the RTM's rate cap will operate to ensure that customers see no net increase in rates prior to a general rate case.

SUPPLEMENTAL

Q. Have you updated the exhibits from your direct and rebuttal testimony to reflect the updated economic analysis for the wind repowering project, as described by Mr. Link?

A. Yes. My 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. The exhibits are in the same format as in the initial filing, and calculate the monthly and annual revenue requirements and the overall impact of the wind repowering projects that would be reflected in rates, assuming operation of the 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 repowering projects' wind construction cost, return, depreciation, PTCs, taxes, and operating costs and benefits. The updated net power cost changes associated with an updated load forecast, system dispatch and revised wind generation projections have been included in the Energy Balancing Account ("EBA") pass-through calculation. Figure 1 is a summary of the estimated repowering revenue requirement found in the revised exhibits. Figure 1 shows that the repowering project now reflects rate benefits to customers beginning in 2022. As a result of the cap proposed for the RTM in this proceeding, customers would see no net change in rates for the repowering project for costs through 2021, absent a general rate case, as discussed in my testimony below.

[1] Exhibit RMP___(JRS-1SD), which provides a revenue requirement overview of the RTM, is changed to reference Mr. Hemstreet's revised exhibit, Confidential Exhibit RMP__(TJH-1SD), in the NPC Savings Base calculation.

Figure 1

Repowering Estimated Revenue Requirement Cost (Benefit)

$thousands

	2019	2020	2021	2022
1 Total Company	$2,233	$21,449	$8,626	-$2,266
2 Utah Allocated	$952	$9,132	$3,664	-$978
3 Utah EBA	$406	-$4,453	-$5,568	-$5,944
4 Utah Deferral	-$406	$4,453	$5,568	$4,965
5 Net Customer Benefit	$0	$0	$0	-$978

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 24.587 percent. 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 6.0 percent—the same carrying charge rate used in the Company's EBA filings, in accordance with Electric Service Schedule No. 94. 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. The Company recently made this same change to the RTM proposed in Docket No. 17-035-40.

Q. What is the updated estimated rate impact of the wind repowering project, which would be reflected in rates through the RTM, in conjunction with the EBA?

A. There would be no net rate change for customers, absent a general rate case, with the RTM through 2021 as a result of the cap proposed by the Company in the initial filing. Without the cap, the RTM would show a net increase to customers of $0.9 million in 2019, $9.6 million in 2020, and $4.1 million in 2021, with a net decrease thereafter.

Q. In the initial and rebuttal filings, the Company projected net benefits to customers in every year in the RTM. Why has that changed?

A. The change is mainly due to the effects of the change in the federal corporate income tax rate and, in particular, the corresponding decline in the PTC gross-up factor. While there is a small increase in the capital investment reflected in the filing, as described by Company witness Mr. Timothy J. Hemstreet, the overall change in the total plant revenue requirement between this supplemental filing and the rebuttal filing is small—from $55.8 million in rebuttal to $56.6 million in this filing in 2020.[2] The more significant driver is the decline in the PTC revenue requirement, shown on line 18 in Exhibit RMP___(JRS-2SD), which decreases from $51.8 million in rebuttal to $43.0

[2] See line 12, column h in Exhibits RMP__(JKL-2R) and RMP__(JRS-2SD).

million in this filing due to the decline in the gross-up factor.

Q. As a result of this filing and the change in near-term rate impacts due to changes in the corporate tax rate, is the Company proposing changes in the RTM for interim ratemaking treatment?

A. No. The Company is not proposing changes to the RTM for the repowering project. However, in light of the changes in the near-term rate impacts due to tax reform, the Company proposes to separately defer the net costs in excess of the cap associated with tax law changes, and seek recovery through an offset to the deferral for the impacts from tax reform, pending in Docket No. 17-035-69.

Q. Why would recovery of the net costs in excess of the RTM cap associated with tax law changes be reasonable as an offset to tax reform impacts?

A. Mr. Link's updated economic analysis shows that the repowering project remains beneficial to customers in all price-policy scenarios, even after taking into account the reduction in value in the PTCs due to tax reform. The Company continues to be committed to smoothing rate impacts and minimizing the number of general rate cases. The RTM and the cap proposed by the Company for the RTM for repowering remain an integral part of this effort. In light of the potential near-term impacts from the reduction the PTC value, in 2020 in particular, it is reasonable to offset the costs in excess of the cap that are related to tax law changes against the expected savings for overall tax reform impacts. Customers would continue to see no net rate change for the repowering project, and the Company would be able to continue to align rate pressures into one general rate case without adverse consequences.

Q. Why is the RTM still necessary?

A. The RTM is designed to match 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 wind repowering assets 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 EBA, without recovery of the benefits of the PTCs 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 wind repowering projects.

Q. Does this conclude your supplemental direct testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(JRS-1SD)
Docket No. 17-035-39
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct Testimony of Joelle R. Steward

Revenue Requirement Overview – Wind Repowering

February 2018

Resource Tracking Mechanism

Revenue Requirement Overview – Wind Repowering

<table>
<tr><th>Category</th><th>Base</th><th>New</th><th>Deferral</th></tr>
<tr><td>Capital Investment</td><td>Zero until the next general rate case. After rate case, the base will be the amount included in the test period, beginning on the rate effective date of that case.</td><td>Actual monthly plant in-service balances associated with wind repowering, beginning with first repowering assets placed in service.</td><td rowspan="7">The difference between the base and new columns will be included in the mechanism calculation until the amounts are fully included in a general rate case, at which time this will end.</td></tr>
<tr><td>Accumulated Depreciation Reserve</td><td>Same as capital investment.</td><td>Monthly depreciation reserve of repowered assets.</td></tr>
<tr><td>Accumulated Deferred Income Tax</td><td>Same as capital investment.</td><td>Actual accumulated deferred income tax balances associated with the repowering investment.</td></tr>
<tr><td>Operation & Maintenance Expense</td><td>Four-year average O&M expense for wind projects from 2014 to 2017, (2018-2019 are excluded to avoid any changes in O&M related to repowering).</td><td>Actual O&M expense for wind projects.</td></tr>
<tr><td>Depreciation Expense</td><td>Zero.</td><td>Actual monthly plant in-service balances associated with wind repowering less the base multiplied by current depreciation rates. The plant in service amounts used will be reduced by the replaced assets until the next depreciation study.</td></tr>
<tr><td>Property Taxes</td><td>Zero.</td><td>Capital Investment deferral less the Depreciation Reserve deferral multiplied by the average property tax rate from the last rate case.</td></tr>
<tr><td>Wind Tax</td><td>Zero.</td><td>Incremental energy production MWh associated with repowering multiplied by the wind tax rate.</td></tr>
<tr><td>NPC Savings</td><td>The EBA tracks and captures any incremental changes to wind production between NPC in base rates and actual NPC.
The base energy production = Actual energy produced by wind projects divided by (1 + percent of generation increase from Confidential Exhibit RMP___(TJH-1SD)).</td><td>The EBA has a 100% pass through of the difference between base NPC and actual NPC. The RTM will capture any savings not included in the EBA related to incremental energy production associated with repowering, and pass these savings back to customers.</td><td>Any incremental wind production not in base rates will be multiplied by monthly HLH and LLH prices, (Mid-C for west and Four Corners for east resources) less wind integration costs.</td></tr>
<tr><td>PTC</td><td>Zero until next general rate case. After a rate case, the base will be the amount included in the test period, starting on the rate effective date, associated with repowering projects.</td><td>Actual MWh eligible for PTC produced by repowered wind plants multiplied by the production tax rate.</td><td>Difference between the base and actual. Tracked until repowering PTCs have expired, and have been reset to zero in base rates.</td></tr>
<tr><td>RTM Cap</td><td>N/A</td><td colspan="2">The Company is proposing to cap the RTM until the next general rate case so that, after taking into account the wind repowering benefits that will flow through the Company's EBA, it will not operate to surcharge customers.</td></tr>
</table>

Rocky Mountain Power
Exhibit RMP___(JRS-2SD)
Docket No. 17-035-39
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct Testimony of Joelle R. Steward

Example Annual RTM Deferral Calculation - Revenue Requirement

February 2018

PacifiCorp
Utah
Wind Repowering - Example Annual RTM Deferral Calculation
Revenue Requirement

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
	$-Thousands		**2019 Repowering**				**2020 Repowering**				**2021 Repowering**				**2022 Repowering**			
Line No.		Reference	**Total Company**	**Factor**	**Factor %**	**Utah Allocated**	**Total Company**	**Factor**	**Factor %**	**Utah Allocated**	**Total Company**	**Factor**	**Factor %**	**Utah Allocated**	**Total Company**	**Factor**	**Factor %**	**Utah Allocated**
	Plant Revenue Requirement																	
1	Capital Investment	Footnote 1	167,208	SG	42.6283%	71,278	967,714	SG	42.6283%	412,520	1,103,618	SG	42.6283%	470,453	1,106,246	SG	42.6283%	471,574
2	Depreciation Reserve	Footnote 1	(908)	SG	42.6283%	(387)	(23,039)	SG	42.6283%	(9,821)	(57,750)	SG	42.6283%	(24,618)	(94,590)	SG	42.6283%	(40,322)
3	Accumulated DIT Balance	Footnote 1	(5,894)	SG	42.6283%	(2,512)	(73,468)	SG	42.6283%	(31,318)	(139,745)	SG	42.6283%	(59,571)	(178,068)	SG	42.6283%	(75,907)
4	Net Rate Base	sum of lines 1-3	160,407			68,379	871,206			371,380	906,123			386,265	833,587			355,344
5	Pre-Tax Rate of Return	line 34	9.209%			9.209%	9.209%			9.209%	9.209%			9.209%	9.209%			9.209%
6	Pre-Tax Return on Rate Base	line 4 * line 5	14,773			6,297	80,233			34,202	83,449			35,573	76,769			32,725
7	Wholesale Wheeling Revenue	Footnote 4	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-
8	Operation & Maintenance	Footnote 3	3,876	SG	42.6283%	1,652	12,137	SG	42.6283%	5,174	12,779	SG	42.6283%	5,448	9,615	SG	42.6283%	4,099
9	Depreciation	Footnote 3 & 6	8,260	SG	42.6283%	3,521	32,635	SG	42.6283%	13,912	36,799	SG	42.6283%	15,687	36,896	SG	42.6283%	15,728
10	Property Taxes	Footnote 3	-	GPS	42.4704%	-	7,370	GPS	42.4704%	3,130	8,162	GPS	42.4704%	3,466	7,898	GPS	42.4704%	3,354
11	Wind Tax	Footnote 3	98	SG	42.6283%	42	338	SG	42.6283%	144	419	SG	42.6283%	178	419	SG	42.6283%	178
12	**Total Plant Revenue Requirement**	sum of lines 6-11	**27,006**			**11,512**	**132,714**			**56,562**	**141,608**			**60,352**	**131,596**			**56,085**
	Net Power Cost																	
13	NPC Incremental Savings	Footnote 3	952	SG	42.6283%	406	(10,446)	SG	42.6283%	(4,453)	(13,062)	SG	42.6283%	(5,568)	(13,943)	SG	42.6283%	(5,944)
	PTC Benefit																	
14	PTC Benefit	Footnote 3	(19,400)	SG	42.6283%	(8,270)	(76,031)	SG	42.6283%	(32,411)	(90,435)	SG	42.6283%	(38,551)	(90,435)	SG	42.6283%	(38,551)
15	PTC Benefit in Base Rates	Footnote 3	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-	-	SG	42.6283%	-
16	Net PTC	sum of lines 14 and 15	(19,400)			(8,270)	(76,031)			(32,411)	(90,435)			(38,551)	(90,435)			(38,551)
17	Gross- up for taxes	line 16 * (line 32 - 1)	(6,325)			(2,696)	(24,788)			(10,567)	(29,485)			(12,569)	(29,485)			(12,569)
18	PTC Revenue Requirement	sum of lines 16 and 17	(25,725)			(10,966)	(100,819)			(42,978)	(119,919)			(51,120)	(119,919)			(51,120)
19	**Rev. Requirement**	sum of lines 12, 13, 18	2,233			952	21,449			9,132	8,626			3,664	(2,266)			(978)
	Adjustment for EBA Pass-through																	
20	NPC Incremental Savings	line 13				406				(4,453)				(5,568)				(5,944)
21	Percentage included in EBA (100%)	UT EBA Sharing %				100%				100%				100%				100%
22	EBA Pass-through	line 20 * line 21				406				(4,453)				(5,568)				(5,944)
23	**Rev. Reqt. after EBA Pass-through**	line 19 - line 22				546				13,584				9,233				4,965
24	**Total Deferral - UT Share**	Footnote 5				(406)				4,453				5,568				4,965
25	**Net Customer Benefit**	line 22 + line 24				-				-				-				(978)
	Deferral Balance - UT Share																	
26	Beginning Deferral Balance	line 30 of previous year				-				(410)				4,394				7,449
27	Monthly Deferral	Footnote 5				(406)				4,453				5,568				4,965
28	Deferral Collection	Footnote 3				-				273				(2,793)				(6,430)
29	Carrying Charge	Footnote 3				(4)				77				279				332
30	**Ending Deferral Balance**	sum of lines 26-29				(410)				4,394				7,449				6,315

31	Federal/State Combined Tax Rate	JRS-4SD, line 5	24.587%	
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JRS-4SD, line 6	1.3260	
33	Deferred Balance Carrying Charge	Footnote 2	4.19%	Carrying Charge Order approved in Docket Nos. 17-035-T02 and 15-035-69
34	Pretax Return	JRS-4SD, line 4	9.209%	13-035-184 Capital Structure & Cost - Ordered
35	Property Tax Rate	JRS-4SD, line 14	0.77%	Property Tax Expense as a percent of Net plant from 13-035-184
36	Utah SG Factor	JRS-4SD, line 15	42.6283%	
37	Utah GPS Factor	JRS-4SD, line 16	42.4704%	

Footnotes:
1) Capital balances equal the average of the monthly balances in JRS-3SD with a one month delay
2) Carrying Charge (line 29) is applied to average monthly deferral balances
3) Equals the sum of each year's monthly values in JRS-3SD
4) Not Applicable for Repowering
5) The Company is proposing to cap the RTM until the next general rate case so that, after taking into account the wind repowering benefits that will flow through the Company's EBA, it will not operate to surcharge customers
6) As stated in testimony, actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study

Rocky Mountain Power
Exhibit RMP___(JRS-3SD)
Docket No. 17-035-39
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct Testimony of Joelle R. Steward

Example Monthly RTM Deferral Calculation - Revenue Requirement

February 2018

PacifiCorp
Utah
Wind Repowering - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2019 January	2019 February	2019 March	2019 April	2019 May	2019 June	2019 July	2019 August	2019 September	2019 October	2019 November	2019 December
	Total Company													
	Plant Revenue Requirement													
1	Capital Investment		-	-	-	-	-	-	145,738	145,738	145,738	602,278	967,000	967,000
2	Depreciation Reserve		-	-	-	-	-	-	(405)	(810)	(1,214)	(2,887)	(5,574)	(8,260)
3	Accumulated DIT Balance		-	-	-	-	-	-	(3,480)	(3,480)	(5,220)	(22,320)	(36,223)	(48,297)
4	Net Rate Base	sum of lines 1-3	-	-	-	-	-	-	141,853	141,448	139,303	577,071	925,204	910,444
5	Pre-Tax Rate of Return	line 34	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%
6	Pre-Tax Return on Rate Base	Footnote 1	-	-	-	-	-	-	-	1,089	1,086	1,069	4,429	7,101
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		-	-	-	-	-	-	316	607	743	747	718	745
9	Depreciation	Footnote 5	-	-	-	-	-	-	405	405	405	1,673	2,686	2,686
10	Property Taxes	Prior December (line 1 + line 2) x line 35	-	-	-	-	-	-	-	-	-	-	-	-
11	Wind Tax		-	-	-	-	-	-	8	15	19	19	18	19
12	**Total Plant Revenue Requirement**	sum of lines 6-11	-	-	-	-	-	-	729	2,116	2,252	3,508	7,851	10,550
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JRS-4SD	-	-	-	-	-	-	78	149	182	184	176	183
	PTC Benefit													
14	PTC Benefit		-	-	-	-	-	-	(1,583)	(3,037)	(3,717)	(3,741)	(3,594)	(3,728)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	-	-	-	-	-	-	(1,583)	(3,037)	(3,717)	(3,741)	(3,594)	(3,728)
17	Gross- up for taxes	line 16 * (line 31 - 1)	-	-	-	-	-	-	(516)	(990)	(1,212)	(1,220)	(1,172)	(1,215)
18	PTC Revenue Requirement	sum of line 16 and 17	-	-	-	-	-	-	(2,099)	(4,027)	(4,929)	(4,961)	(4,766)	(4,943)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	-	-	-	-	-	-	(1,293)	(1,763)	(2,495)	(1,269)	3,261	5,790
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	-	-	-	-	-	-	78	149	182	184	176	183
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	-	-	-	-	-	-	78	149	182	184	176	183
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	-	-	-	-	-	-	(1,370)	(1,912)	(2,677)	(1,452)	3,085	5,607
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	-	-	-	-	-	-	(33)	(64)	(78)	(78)	(75)	(78)
25	**Net Customer Benefit**	line 22 * line 36 + line 24	-	-	-	-	-	-	-	-	-	-	-	-
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	-	-	-	-	-	-	-	(33)	(97)	(175)	(254)	(330)
27	Monthly Deferral	line 24	-	-	-	-	-	-	(33)	(64)	(78)	(78)	(75)	(78)
28	Deferral Collection	Footnote 3	-	-	-	-	-	-	-	-	-	-	-	-
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	-	-	-	-	-	-	(0)	(0)	(0)	(1)	(1)	(1)
30	**Ending Deferral Balance**	sum of lines 26-29	-	-	-	-	-	-	(33)	(97)	(175)	(254)	(330)	(410)
31	Federal/State Combined Tax Rate	JRS-4SD, line 5	24.587%											
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JRS-4SD, line 6	1.3260											
33	Deferred Balance Carrying Charge	see JRS-2SD line 33	4.19%											
34	Pretax Return	JRS-4SD, line 4	9.209%											
35	Property Tax Rate	JRS-4SD, line 14	0.77%											
36	Utah SG Factor	JRS-4SD, line 15	42.6283%											
37	Utah GPS Factor	JRS-4SD, line 16	42.4704%											

Footnotes:
1) Pre-tax Return, line 6, is calculated as the rate of return (line 5) multiplied by the ending net rate base of the prior month (line 4) divided by 12
2) Not Applicable for Repowering
3) For illustrative purposes, collection of December's balance is assumed to be collected beginning the following May 1
4) The Company is proposing to cap the RTM until the next general rate case so that, after taking into account the wind repowering benefits that will flow through the Company's EBA, it will not operate to surcharge customers
5) As stated in testimony, actual depreciation expense will be adjusted by the impact of the retired assets until the next depreciation study

PacifiCorp
Utah
Wind Repowering - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2020 January	2020 February	2020 March	2020 April	2020 May	2020 June	2020 July	2020 August	2020 September	2020 October	2020 November	2020 December
	Total Company													
	Plant Revenue Requirement													
1	Capital Investment		967,000	967,000	967,000	967,000	967,000	967,000	968,712	968,712	968,712	968,712	968,712	1,102,607
2	Depreciation Reserve		(10,946)	(13,632)	(16,318)	(19,004)	(21,690)	(24,376)	(27,067)	(29,758)	(32,449)	(35,140)	(37,832)	(40,894)
3	Accumulated DIT Balance		(48,297)	(48,297)	(65,078)	(65,078)	(65,078)	(81,858)	(81,858)	(81,858)	(98,639)	(98,639)	(98,639)	(122,279)
4	Net Rate Base	sum of lines 1-3	907,758	905,072	885,605	882,919	880,233	860,766	859,786	857,095	837,624	834,932	832,241	939,434
5	Pre-Tax Rate of Return	line 34	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%
6	Pre-Tax Return on Rate Base	Footnote 1	6,987	6,967	6,946	6,797	6,776	6,755	6,606	6,598	6,578	6,428	6,408	6,387
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		846	921	1,042	1,076	1,047	988	1,017	916	1,037	1,100	1,059	1,088
9	Depreciation	Footnote 5	2,686	2,686	2,686	2,686	2,686	2,686	2,691	2,691	2,691	2,691	2,691	3,063
10	Property Taxes	Prior December (line 1 + line 2) x line 35	614	614	614	614	614	614	614	614	614	614	614	614
11	Wind Tax		24	26	29	30	29	28	28	26	29	31	30	30
12	**Total Plant Revenue Requirement**	sum of lines 6-11	11,157	11,213	11,318	11,203	11,152	11,071	10,957	10,846	10,949	10,864	10,801	11,182
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JRS-4SD	(728)	(793)	(897)	(926)	(901)	(850)	(876)	(789)	(893)	(946)	(911)	(936)
	PTC Benefit													
14	PTC Benefit		(5,297)	(5,768)	(6,530)	(6,743)	(6,559)	(6,188)	(6,373)	(5,741)	(6,499)	(6,888)	(6,631)	(6,814)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(5,297)	(5,768)	(6,530)	(6,743)	(6,559)	(6,188)	(6,373)	(5,741)	(6,499)	(6,888)	(6,631)	(6,814)
17	Gross- up for taxes	line 16 * (line 31 - 1)	(1,727)	(1,881)	(2,129)	(2,198)	(2,138)	(2,017)	(2,078)	(1,872)	(2,119)	(2,246)	(2,162)	(2,222)
18	PTC Revenue Requirement	sum of line 16 and 17	(7,024)	(7,649)	(8,659)	(8,941)	(8,697)	(8,206)	(8,451)	(7,612)	(8,617)	(9,134)	(8,793)	(9,035)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	3,405	2,772	1,761	1,336	1,554	2,015	1,630	2,445	1,439	783	1,097	1,211
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	(728)	(793)	(897)	(926)	(901)	(850)	(876)	(789)	(893)	(946)	(911)	(936)
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	(728)	(793)	(897)	(926)	(901)	(850)	(876)	(789)	(893)	(946)	(911)	(936)
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	4,133	3,564	2,658	2,262	2,455	2,866	2,506	3,233	2,332	1,730	2,008	2,147
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	310	338	382	395	384	362	373	336	381	403	388	399
25	**Net Customer Benefit**	line 22 * line 36 + line 24	-	-	-	-	-	-	-	-	-	-	-	-
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	(410)	(100)	238	622	1,019	1,442	1,844	2,258	2,637	3,062	3,511	3,946
27	Monthly Deferral	line 24	310	338	382	395	384	362	373	336	381	403	388	399
28	Deferral Collection	Footnote 3	-	-	-	-	34	34	34	34	34	34	34	34
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	(1)	0	1	3	4	6	7	8	10	11	13	14
30	**Ending Deferral Balance**	sum of lines 26-29	(100)	238	622	1,019	1,442	1,844	2,258	2,637	3,062	3,511	3,946	4,394
31	Federal/State Combined Tax Rate	JRS-4SD, line 5												
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JRS-4SD, line 6												
33	Deferred Balance Carrying Charge	see JRS-2SD line 33												
34	Pretax Return	JRS-4SD, line 4												
35	Property Tax Rate	JRS-4SD, line 14												
36	Utah SG Factor	JRS-4SD, line 15												
37	Utah GPS Factor	JRS-4SD, line 16												

PacifiCorp
Utah
Wind Repowering - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2021 January	2021 February	2021 March	2021 April	2021 May	2021 June	2021 July	2021 August	2021 September	2021 October	2021 November	2021 December
	Total Company													
	Plant Revenue Requirement													
1	Capital Investment		1,102,607	1,102,607	1,102,607	1,102,607	1,102,607	1,102,607	1,105,033	1,105,033	1,105,033	1,105,033	1,105,033	1,105,033
2	Depreciation Reserve		(43,957)	(47,020)	(50,083)	(53,146)	(56,209)	(59,272)	(62,342)	(65,413)	(68,483)	(71,553)	(74,623)	(77,693)
3	Accumulated DIT Balance		(122,279)	(122,279)	(133,923)	(133,923)	(133,923)	(145,567)	(145,567)	(145,567)	(157,212)	(157,212)	(157,212)	(168,856)
4	Net Rate Base	sum of lines 1-3	936,371	933,308	918,601	915,538	912,475	897,767	897,123	894,053	879,338	876,268	873,198	858,483
5	Pre-Tax Rate of Return	line 34	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%
6	Pre-Tax Return on Rate Base	Footnote 1	7,210	7,186	7,163	7,050	7,026	7,003	6,890	6,885	6,861	6,749	6,725	6,701
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065	1,065
9	Depreciation	Footnote 5	3,063	3,063	3,063	3,063	3,063	3,063	3,070	3,070	3,070	3,070	3,070	3,070
10	Property Taxes	Prior December (line 1 + line 2) x line 35	680	680	680	680	680	680	680	680	680	680	680	680
11	Wind Tax		35	35	35	35	35	35	35	35	35	35	35	35
12	**Total Plant Revenue Requirement**	sum of lines 6-11	12,053	12,029	12,006	11,893	11,869	11,846	11,740	11,735	11,712	11,599	11,575	11,552
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JRS-4SD	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)
	PTC Benefit													
14	PTC Benefit		(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)
17	Gross- up for taxes	line 16 * (line 31 - 1)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)
18	PTC Revenue Requirement	sum of line 16 and 17	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	971	947	924	811	788	764	658	653	630	517	493	470
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)	(1,089)
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	2,059	2,036	2,012	1,900	1,876	1,853	1,747	1,742	1,718	1,605	1,582	1,558
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	464	464	464	464	464	464	464	464	464	464	464	464
25	**Net Customer Benefit**	line 22 * line 36 + line 24	-	-	-	-	-	-	-	-	-	-	-	-
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	4,394	4,908	5,424	5,942	6,461	6,583	6,706	6,828	6,952	7,075	7,199	7,324
27	Monthly Deferral	line 24	464	464	464	464	464	464	464	464	464	464	464	464
28	Deferral Collection	Footnote 3	34	34	34	34	(366)	(366)	(366)	(366)	(366)	(366)	(366)	(366)
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	16	18	20	21	24	24	25	25	26	26	27	27
30	**Ending Deferral Balance**	sum of lines 26-29	4,908	5,424	5,942	6,461	6,583	6,706	6,828	6,952	7,075	7,199	7,324	7,449
31	Federal/State Combined Tax Rate	JRS-4SD, line 5												
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JRS-4SD, line 6												
33	Deferred Balance Carrying Charge	see JRS-2SD line 33												
34	Pretax Return	JRS-4SD, line 4												
35	Property Tax Rate	JRS-4SD, line 14												
36	Utah SG Factor	JRS-4SD, line 15												
37	Utah GPS Factor	JRS-4SD, line 16												

PacifiCorp
Utah
Wind Repowering - Example Monthly RTM Deferral Calculation
Revenue Requirement

Line No.	$-Thousands	Reference	2022 January	2022 February	2022 March	2022 April	2022 May	2022 June	2022 July	2022 August	2022 September	2022 October	2022 November	2022 December
	Total Company													
	Plant Revenue Requirement													
1	Capital Investment		1,105,033	1,105,033	1,105,033	1,105,033	1,105,033	1,105,033	1,107,944	1,107,944	1,107,944	1,107,944	1,107,944	1,107,944
2	Depreciation Reserve		(80,763)	(83,834)	(86,904)	(89,974)	(93,044)	(96,114)	(99,193)	(102,272)	(105,352)	(108,431)	(111,510)	(114,589)
3	Accumulated DIT Balance		(168,856)	(168,856)	(174,998)	(174,998)	(174,998)	(181,139)	(181,139)	(181,139)	(187,281)	(187,281)	(187,281)	(193,422)
4	Net Rate Base	sum of lines 1-3	855,413	852,343	843,131	840,061	836,991	827,779	827,612	824,533	815,312	812,233	809,154	799,933
5	Pre-Tax Rate of Return	line 34	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%	9.209%
6	Pre-Tax Return on Rate Base	Footnote 1	6,588	6,565	6,541	6,471	6,447	6,424	6,353	6,352	6,328	6,257	6,234	6,210
7	Wholesale Wheeling Revenue	Footnote 2	-	-	-	-	-	-	-	-	-	-	-	-
8	Operation & Maintenance		801	801	801	801	801	801	801	801	801	801	801	801
9	Depreciation	Footnote 5	3,070	3,070	3,070	3,070	3,070	3,070	3,079	3,079	3,079	3,079	3,079	3,079
10	Property Taxes	Prior December (line 1 + line 2) x line 35	658	658	658	658	658	658	658	658	658	658	658	658
11	Wind Tax		35	35	35	35	35	35	35	35	35	35	35	35
12	**Total Plant Revenue Requirement**	sum of lines 6-11	11,153	11,129	11,106	11,035	11,012	10,988	10,926	10,925	10,901	10,831	10,807	10,783
	Net Power Cost													
13	NPC Incremental Savings	See Exhibit JRS-4SD	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)
	PTC Benefit													
14	PTC Benefit		(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)
15	PTC Benefit in Base Rates		-	-	-	-	-	-	-	-	-	-	-	-
16	Net PTC	sum of lines 14 and 15	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)	(7,536)
17	Gross- up for taxes	line 16 * (line 31 - 1)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)	(2,457)
18	PTC Revenue Requirement	sum of line 16 and 17	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)	(9,993)
19	**Rev. Requirement**	sum of lines 12, 13 and 18	(2)	(26)	(49)	(120)	(144)	(167)	(229)	(230)	(254)	(325)	(348)	(372)
	Adjustment for EBA Pass-through													
20	NPC Incremental Savings	line 13	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)
21	Percentage included in EBA (100%)		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	EBA Pass-through	line 20 * line 21	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)	(1,162)
23	**Rev. Reqt after EBA Pass-through**	line 19 - line 22	1,160	1,136	1,113	1,042	1,018	995	933	932	908	837	814	790
	Utah Allocated													
24	**Total Deferral - UT Share**	Footnote 4	493	483	473	443	433	423	397	396	386	356	346	336
25	**Net Customer Benefit**	line 22 * line 36 + line 24	(2)	(12)	(22)	(52)	(62)	(72)	(99)	(99)	(109)	(139)	(149)	(160)
	Deferral Balance - UT Share													
26	Beginning Deferral Balance	line 30 of previous month	7,449	7,603	7,748	7,884	7,990	7,832	7,663	7,468	7,271	7,064	6,825	6,576
27	Monthly Deferral	line 24	493	483	473	443	433	423	397	396	386	356	346	336
28	Deferral Collection	Footnote 3	(366)	(366)	(366)	(366)	(621)	(621)	(621)	(621)	(621)	(621)	(621)	(621)
29	Carrying Charge	(ln 26 + .5 * (ln 27 - ln 28)) * ln 33	28	28	29	29	30	29	29	28	27	26	26	25
30	**Ending Deferral Balance**	sum of lines 26-29	7,603	7,748	7,884	7,990	7,832	7,663	7,468	7,271	7,064	6,825	6,576	6,315
31	Federal/State Combined Tax Rate	JRS-4SD, line 5												
32	Net to Gross Bump up Factor = (1/(1-tax rate))	JRS-4SD, line 6												
33	Deferred Balance Carrying Charge	see JRS-2SD line 33												
34	Pretax Return	JRS-4SD, line 4												
35	Property Tax Rate	JRS-4SD, line 14												
36	Utah SG Factor	JRS-4SD, line 15												
37	Utah GPS Factor	JRS-4SD, line 16												

Total Plant Revenue Requirement (Lines 1 - 12, 34):
Exhibit JRS-3SD shows the calculation of the RTM revenue requirement deferral described in my testimony. The calculation starts with total Company amounts on lines 1 - 23 to calculate the Utah specific amounts on lines 24 - 30. To calculate the return on rate base associated with the wind repowering investment, net rate base associated with the repowered wind resources is calculated on a monthly basis. The net rate base balance on line 4 includes the investment in repowered wind resources, along with the associated impacts on the depreciation reserve and accumulated DIT Balance. The monthly beginning net rate base (the final amount from the prior month) is then multiplied by the pre-tax Weighted Average Cost of Capital ("WACC") from the last Utah general rate case on line 5 to determine the Company's pre-tax return on rate base on line 6. The example uses the pre-tax WACC from Docket No. 09-035-15. The total plant revenue requirement is calculated by taking the return on rate base shown on line 6 and adding the O&M expense, depreciation expense, property taxes and wind tax on lines 8 - 11 to determine the total plant revenue requirement on line 12. Wholesale wheeling revenue on line 7 is not used for wind repowering, but is needed for a similar calculation for the Gateway transmission and wind expansion project.

Net Power Costs (Line 13):
The total company incremental NPC savings associated with repowered wind resources is shown on line 13. The incremental NPC savings associated with the repowered wind projects are multiplied by one hundred percent on line 21 to determine the amount of the NPC savings that will be returned to customers through the sharing band of the EBA. The calculation of NPC savings is described in Exhibit JRS-4SD.

PTC Benefits (Lines 14-18, 31, 32):
Lines 14-18 show the calculation of the PTC benefits associated with the repowered wind resources. The actual PTC sales are grossed-up for taxes using the net-to-gross bump-up factor from the Company's last general rate case (shown on line 32) to derive the PTC revenue requirement on line 18. The tax gross-up is necessary for customers to get the full revenue requirement benefit of the PTCs and is calculated using the federal and state combined tax rate shown on line 31, which was also included in the last general rate case.

Deferral Balance (Lines 19 – 30):
The Utah share of the net deferral begins by calculating the total repowering project revenue requirement on line 19, which is the sum of Total Plant Revenue Requirement on line 12, NPC Incremental Savings on line 13, and PTC Revenue Requirement on line 18. The EBA pass-through on line 22 is subtracted to provide the Revenue Requirement after EBA Pass-through on line 23. Utah's share of the Total Deferral is dependent upon the amount of revenue requirement cost or benefit that is determined in a particular year. If the Revenue Requirement after EBA Pass-through for any year on line 23 is negative, which means that the repowering project provides a revenue requirement benefit greater than the benefit being passed through the EBA, then that year's deferral is equal to the additional benefit found on line 23. If the Revenue Requirement after EBA Pass-through for any year on line 23 is positive, the Company is proposing to cap the RTM until the next general rate case so that, after taking into account the wind repowering benefits that will flow through the Company's EBA, it will not operate to surcharge customers. The Net Customer Benefit (line 25) is the sum of the EBA Pass-through (line 22) and the Total Deferral - Utah Share (line 24). The carrying charge, shown on line 29 is calculated using the Commission-authorized rate on line 33 and is consistent with the calculations used in the Company's other mechanisms such as the EBA. As described earlier, each month the total-Company RTM revenue requirement will be calculated as illustrated on Exhibit JRS-3SD to align with the resources included in the EBA. Once per year on a calendar-year basis, the Company will sum the monthly RTM revenue requirement entries to prepare the annual RTM application for filing with the Commission on March15, with an interim rate effective date that corresponds with the EBA application, May 1.

Rocky Mountain Power
Exhibit RMP___(JRS-4SD)
Docket No. 17-035-39
Witness: Joelle R. Steward

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Supplemental Direct Testimony of Joelle R. Steward

Capital Structure, Property Tax Rate and Net Power Cost Description

February 2018

PacifiCorp
Utah
Wind Repowering - Capital Structure, Property Tax and Net Power Cost Description
Capital Structure and Property Tax Rate

13-035-184 Capital Structure & Cost
Updated with new consolidated tax rate consistent with the new tax law
Effective 9/1/2014

Line no.	Capital Structure	Capital Structure	Capital Cost	Weighted Cost	Pre-Tax Cost
1	Debt	48.556%	5.200%	2.525%	2.525%
2	Preferred	0.016%	6.753%	0.001%	0.001%
3	Common	51.428%	9.800%	5.040%	6.683%
4			**TOTAL**	**7.566%**	**9.209%**
5	Consolidated Tax Rate		24.587%		
6	Tax Gross-up factor for PTC = (1/(1 - tax rate))		1.3260		
	Property Tax Calculation as filed in Docket Number 13-035-184				
7	Total Company				134,961,526
8	Utah GPS Factor				42.4704%
9	Utah Property Taxes				57,318,700
10	Utah Gross EPIS				10,912,081,614
11	Utah Accum. Depr.				(3,234,910,020)
12	Utah Accum. Amort.				(221,249,967)
13	Utah Net EPIS				7,455,921,626
14	Estimated Utah Property Tax Rate				0.769%
15	Utah SG Factor - Docket No. 13-035-184				42.6283%
16	Utah GPS Factor - Docket No. 13-035-184				42.4704%

Net Power Cost Incremental Savings Calculation and Definitions

Incremental Generation = Wind Plant Generation MWh – Base Wind Plant Generation MWh

Base Wind Plant Generation = Wind Plant Generation MWh / (1 + Project Generation Increase %)

$$
\begin{aligned}
&NPC\ Incremental\ Savings \\
&\quad = [Incremental\ Gen_{HLH} \times (Monthly\ Market\ Price_{HLH} - Integration\ Costs)] \\
&\quad + [Incremental\ Gen_{LLH} \times (Monthly\ Market\ Price_{LLH} - Integration\ Costs)]
\end{aligned}
$$

$$RTM\ NPC\ Benefit = NPC\ Incremental\ Savings \times EBA\ Sharing\ Band$$

Where:

Incremental Generation = The increase in generation at the wind plant due to repowering
Project Generation Increase % = The percentage change in energy at the wind plant due to repowering (See Confidential Exhibit RMP__TJH-1SD)
$Incremental\ Gen_{HLH}$ *= The increase in generation at the wind plant due to repowering during heavy load hours*
$Incremental\ Gen_{LLH}$ *= The increase in generation at the wind plant due to repowering during light load hours*
$Monthly\ Market\ Price_{HLH}$ *= Heavy load hour monthly market price*
$Monthly\ Market\ Price_{LLH}$ *= Light load hour monthly market price*
Integration Costs = Wind integration costs from the most recent IRP
RTM NPC Benefit = The NPC repowering benefit absorbed by the Company in the EBA as a result of the sharing band

Rocky Mountain Power
Docket No. 17-035-39
Witness: Nikki L. Kobliha

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Supplemental Direct Testimony of Nikki L. Kobliha

February 2018

SUPPLEMENTAL DIRECT TESTIMONY

Q. Are you the same Nikki L. Kobliha who previously provided rebuttal testimony in this case on behalf of Rocky Mountain Power ("Company"), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your supplemental direct testimony in this proceeding?

A. My supplemental direct testimony discusses the impact of the final tax reform legislation passed in December 2017 and supports the Company's request for approval of the Company's significant energy resource decision for wind repowering. In my supplemental direct testimony, I outline relevant provisions in the federal income tax reform enacted in December 2017. I confirm there are no changes to current federal income tax law on production tax credits ("PTCs"), which provide significant value to the wind repowering project.

Q. Please summarize your testimony.

A. In December 2017, the U.S. Congress passed, and the President signed, H.R 1 ("Tax Act"), which included significant federal income tax reforms. The passage of the Tax Act resolved any risk that federal tax reform posed to the wind repowering project. The Tax Act sets a new corporate income tax rate, now incorporated in the Company's updated economic analysis presented by Company witness Mr. Rick T. Link. The Tax Act also confirms the continued availability of PTCs for the wind repowering project, from which much of their economic benefit is derived. The enactment of the Tax Act therefore resolves the concerns on this issue because the impacts are now known and incorporated into the economic analysis.

SUPPLEMENTAL DIRECT TESTIMONY

Q. When was the Tax Act enacted?

A. The Tax Act was signed into law by the President on December 22, 2017.

Q. When does the Tax Act become effective?

A. The Tax Act generally becomes effective for years beginning after December 31, 2017.

Q. Does the Tax Act reduce the Company's federal income tax rate?

A. Yes, the Tax Act reduces the Company's federal income tax rate from 35 percent to 21 percent.

Q. For purposes of the repowering project, is there a difference between the federal statutory income tax rate and effective tax rate under the Tax Act?

A. No, absent the impact of the PTCs. Thus, the Company's updated economic modeling described by Mr. Link appropriately used a 21 percent tax rate.

Q. Does the reduction in the corporate tax rate directly affect the value of PTCs?

A. No, the reduction in the corporate income tax rate does not directly impact the value of the PTCs. It does, however, impact the tax gross-up value of the PTCs to customers.

Q. Does the Tax Act change any aspect of federal income tax law related to PTCs?

A. No. There were no modifications to the federal income tax code or any Internal Revenue Service guidance relating to the PTCs. Thus, there were no changes to the five-percent safe-harbor equipment purchase requirement, the 80/20 test for repowered wind facilities, and the continuous construction requirement that I discussed in my rebuttal and surrebuttal testimony (*See* Kobliha Rebuttal, lines 31-35).

Q. Are there any other provisions of the Tax Act that affect the wind repowering project?

A. Yes. Two other impacts associated with the reduction in the corporate income tax rate exist. A reduction to the corporate income tax rate reduces the tax gross-up, lowering the Company's overall rate of return on the wind repowering project. The lower tax rate also reduces the accumulated deferred income tax liability related to the use of Modified Accelerated Cost Recovery System ("MACRS") accelerated depreciation for the five-year tax life of the Wind Projects, which will increase the net rate base balance.

Bonus depreciation rules have also changed. Under prior income tax law, repowered wind projects placed in service in 2019 by the Company would have received 30 percent bonus depreciation. Repowered wind projects placed in service in 2020 would have received no bonus depreciation. The new tax reform legislation generally provides that regulated utilities like the Company will not be allowed to use bonus depreciation on projects placed in service after September 27, 2017. The Wind Projects, however, remain subject to the five-year MACRS accelerated depreciation. The impacts of the reduction in the corporate income tax rate and the elimination of bonus deprecation for regulated utilities has been fully reflected in the updated economic analysis prepared by Mr. Link.

Q. Does the reduction in the Company's federal income tax rate make the wind repowering project uneconomic?

A. No, as demonstrated in Mr. Link's updated economic analysis of the wind repowering project.

Q. At this point, do you foresee any future tax reform legislation that will materially impact the economics of the wind repowering project?

A. No. As discussed above, the federal corporate tax rate has decreased to 21 percent beginning in 2018, and there is no reason to believe that another decrease will occur in the near future. As described by Mr. Link, the wind repowering project continues to provide substantial customer benefits under the Company's new 21 percent federal tax rate.

Q. Does this conclude your supplemental direct testimony?

A. Yes.