ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple, Suite 330
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April 23, 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—Supplemental Rebuttal Testimony

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 Rebuttal testimony. Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

By E-mail (preferred): datarequest@pacificorp.com
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By regular mail: Data Request Response Center
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Portland, OR 97232

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

Sincerely,

Joelle Steward
Vice President, Regulation

CERTIFICATE OF SERVICE

I hereby certify that on April 23, 2018, a true and correct copy of the foregoing was served by electronic mail and overnight delivery to the following:

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Rocky Mountain Power
Docket No. 17-035-39
Witness: Gary W. Hoogeveen

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Supplemental Rebuttal Testimony of Gary W. Hoogeveen

April 2018

Q. Please state your name, business address, and present position.

A. My name is Gary Hoogeveen. My business address is 1407 West North Temple, Suite 310, Salt Lake City, Utah 84116. I am Senior Vice President and Chief Commercial Officer of Rocky Mountain Power ("Company"), a division of PacifiCorp.

Q. Briefly describe your professional experience.

A. I have a B.S. degree in Physics from the University of Northern Iowa and Masters and Ph.D. degrees in Space Physics from Rice University. For the last 16 years I have worked for the Berkshire Hathaway Energy family of companies. In the five years immediately preceding my current position at Rocky Mountain Power, I served as President of the Kern River Transmission Company headquartered in Salt Lake City. I joined Rocky Mountain Power in November 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have filed testimony in proceedings before the Public Service Commission of Utah ("Commission").

Q. Are you adopting the direct, rebuttal, and supplemental direct testimonies of Cindy A. Crane in this case?

A. Yes.

PURPOSE AND SUMMARY OF SUPPLEMENTAL REBUTTAL TESTIMONY

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

A. I support the Company's request for approval of the wind repowering project by providing a policy response to the testimony of the Utah Division of Public Utilities ("DPU"), the Office of Consumer Services ("OCS"), and Utah Association of Energy Users ("UAE"), filed on April 2, 2018.

Q. Please summarize your testimony.

A. The wind repowering project is a key element of PacifiCorp's least-cost, least-risk plan to serve customers. Under virtually all scenarios, the Company's resource decision to repower its wind fleet will provide net benefits to Utah customers—a fact demonstrated by the Company's economic analysis and the analysis of DPU, OCS and UAE. The high likelihood of net benefits has not changed throughout this case. What has changed is the risk profile of the wind repowering project, which has steadily decreased over time. During the course of this case, the Company has addressed or mitigated the major risks identified by the parties, including cost overruns, facility-specific economics, permitting, tax reform, production tax credit ("PTC") qualification, and wind performance.

Wind repowering makes sense for Utah customers. For a proposed investment of $1.101 billion, the Company will receive and pass directly to customers PTC benefits of $1.26 billion over ten years, increase the energy production of its wind fleet by an average of 25.7 percent, and improve the overall performance and expected life of its wind facilities. The benefits of repowering are clear and demonstrate why this time-limited resource opportunity for customers is prudent, in the public interest, and should be approved.

PUBLIC INTEREST

Q. Has the Company's proposed resource decision to repower its wind fleet changed in any material way from its initial filing in June 2017?

A. No, other than the fact that overall costs estimates have decreased, and projected energy production has increased. The Company proposes to upgrade or "repower"

999.1 megawatts ("MW") of Company-owned wind capacity by installing longer blades and new nacelles, enabling a significant increase in energy production. Repowering extends the life of the wind facilities and allows them to requalify for PTCs for an additional 10 years. The resource proposal includes 12 wind facilities located in Wyoming, Washington and Oregon. Wind repowering is a time-limited resource opportunity because the repowered facilities must be commercially operational by the end of 2020 to qualify for the PTCs.

Q. What are the requirements for approval of the repowering project under Utah Code Ann. § 54-17-402(3)(b)?

A. I understand that the Commission must determine whether the resource decision is in the public interest, considering the following:

- Whether the decision will most likely result in the acquisition, production, and delivery of service at the lowest reasonable cost to the customers;
- Long-term and short-term impacts;
- Risk;
- Reliability;
- Financial impacts on the utility; and
- Other factors determined by the Commission to be relevant.

Q. Based on these factors, is the wind repowering project in the public interest?

A. Yes. The wind repowering project satisfies the Commission's public interest considerations by reducing customer costs and risks, and increasing reliability. Specifically, repowering: (1) increases energy production; (2) reduces ongoing operating costs associated with aging wind turbines; (3) extends the useful lives of the wind facilities by at least ten years; (4) provides PTCs for an additional 10 years; and

(5) improves the ability of the wind facilities to deliver cost-effective, renewable energy into the transmission system through enhanced voltage support and power quality.

Q. Does the Company's economic analysis demonstrate that the wind repowering project will result in utility service at the lowest reasonable costs to customers?

A. Yes. The Company's current economic analysis, described in Mr. Rick T. Link's supplemental direct and rebuttal testimony, shows that the wind repowering project is part of the least-cost, least-risk portfolio of resources to serve customers. Over the life of the facilities, the repowering project results in present-value customer net benefits in *all* price-policy scenarios, ranging from $121 million (low gas, medium carbon dioxide ("CO_2")) to $466 million (high gas, high CO_2). Using the Company's Integrated Resource Plan ("IRP") models and 20-year planning horizon, the repowering project also shows net benefits in *all* price-policy scenarios, ranging from $139 million (low gas, medium CO_2) to $273 million (high gas, high CO_2). These results indicate that the Company's expected revenue requirement is substantially lower with repowering than without repowering in all cases, making it the lowest reasonable cost option for customers.

Q. To respond to parties' issues and concerns, did the Company extend the review schedule and provide additional economic analysis in this case?

A. Yes. The normal timeline for review of voluntary requests for approval of resource decisions is 180 days. Utah Code Ann. § 54-17-402(6). This case has now been pending for approximately 10 months, or 300 days. In addition, the Company has responded to parties' requests for additional studies by producing analysis that reflects a project-by-project review, changing market conditions, and changes in tax law.

The Company understands that parties were frustrated that the Company's Energy Vision 2020 proposals, including wind repowering, arose at the end of the 2017 Integrated Resource Plan public process and truncated their review. The Company hopes that the 10-month review process in this case, along with the Company's extensive, corroborating analysis develoed in this case using its IRP models, addresses this concern.

Q. Over the course of this case, have the benefits of repowering become more certain, while the risks have decreased?

A. Yes. As described by Mr. Timothy J. Hemstreet, over the last 10 months, the wind repowering project has evolved favorably for customers:

- Estimated costs decreased by 2.4 percent
- Turbine equipment costs are now fixed for all wind facilities, and installation costs are guaranteed for eight of the 12 wind facilities.
- Operations and maintenance ("O&M") costs are largely fixed for the first 10 years for eight of the 12 facilities.
- Incremental energy production increased by 6.5 percent from the estimates included in the original filing, as the Company finalized its turbine selection process to obtain higher-performing turbines for less cost.
- The Company prudently negotiated, or is in the process of negotiating, customer protections to guarantee ongoing equipment availability, which provide greater certainty to the estimated energy production from the repowered facilities.
- The Company has insulated customers from risk associated with construction delays that might compromise PTC eligibility through contractual provisions with turbine suppliers and installers.
- The Company has maintained a substantial cushion both in terms of project costs (for purposes of the five-percent safe harbor) and construction schedules to mitigate PTC-eligibility risk.
- Permitting risk is largely resolved—the Company has final permits for 11 of the 12 wind facilities and expects to complete permitting for the final facility soon.

- Engineering studies are now substantially complete, and the costs associated with final turbine selection and necessary foundation retrofits are included in the Company's cost estimate and economic analysis.

- Wind repowering remains beneficial for customers after accounting for recent changes in the federal tax code.

Q. Several parties claim that the repowering project does not provide the lowest reasonable cost utility service because the estimated benefits are not large enough under every scenario studied. (*See, e.g.*, Hayet Resp., lines 585–587.) How do you respond to these critiques?

A. I disagree that the Commission should approve the wind repowering project only if it meets a specified threshold for benefits under every scenario studied. In the vast majority of scenarios and sensitivities—including those studied by DPU, OCS and UAE—the wind repowering project shows net benefits. Rejecting the project would thus produce higher-cost utility service in almost every circumstances and would not meet the public interest standard. Without repowering, customers also bear the risk associated with market purchases or other costs incurred to produce the energy that would have been produced by the repowered facilities.

Q. Has the Commission previously required a demonstration of net benefits in all scenarios to approve a voluntary resource decision?

A. Not to my knowledge. For example, when the Company sought approval for its voluntary resource decision to install environmental upgrades at the Jim Bridger plant, the Commission found that the resource decision met the statutory standard based on analysis showing that the decision was the most beneficial in six of the nine scenarios modeled. *See In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct Selective Catalytic Reduction Systems on*

Jim Bridger Units 3 and 4, Docket No. 12-035-92, Redacted Report and Order at 13 (May 10, 2013).

Q. Does the parties' analysis support approval of the repowering project?

A. Yes. Even though parties recommend against approval of the repowering project, their own analysis shows that repowering provides customer benefits under nearly every scenario studied. For example, DPU's analysis shows:

- Through 2036, *all the repowered facilities* provide net benefits under both the medium natural gas/medium CO_2 and low natural gas/zero CO_2 scenarios.

- Through 2050, *all the repowered facilities* provide net benefits under the medium price-policy scenario, nine provide net benefits under all four scenarios studied, two provide net benefits in three of the four scenarios studied, and one provides net benefits in one of the four scenarios studied. Thus, there are net benefits in 43 of 48 scenarios studied. (Peaco Resp., line 399, Table 4.)

OCS's analysis shows:

- Through 2036 (OCS's preferred timeframe for measuring customer benefits), 11 of the 12 repowered facilities produce net benefits under both the medium natural gas/medium CO_2 and low natural gas/zero CO_2 scenarios. (Hayet Resp., line 569, Table 5.)

UAE's analysis shows:

- Through 2036, the repowering project provides net benefits under all nine price-policy scenarios ranging from $100 million to $235 million. (Higgins Resp., line 500, Table KCH-7-RE.)

- Through 2036, 11 of the 12 repowered facilities produce net benefits under both the medium natural gas/medium CO_2 and low natural gas/zero CO_2 scenarios. (Higgins Resp., line 622, Table KCH-13-RE; line 628, Table KCH-14-RE.)

Q. Notwithstanding the repowering project's decreasing risk profile, some parties still raise concerns about PTC qualification. (*See, e.g.*, Zenger Resp., lines 184–202; 228–244.) Does the Company stand by its commitment to assume the risk of non-qualification for PTCs if it is related to the Company's performance?

A. Yes. If the repowered facilities are not 100-percent PTC eligible because of some occurrence within the Company's control, shareholders will hold customers harmless. This commitment extends to entities with whom the Company has contracted for services including contractors, vendors, and suppliers—meaning that if the failure to qualify for PTCs is due to an event within a contractor's control, the Company will hold customers harmless.

Q. How will the Company determine if an event is within its control?

A. Generally, an event is beyond the reasonable control of the Company if it is the result of a change in law or would qualify as a force majeure event as that term is used in the relevant agreements between the Company and its contractors.

CONCLUSION

Q. What is your recommendation to the Commission?

A. I recommend that by June 1, 2018, the Commission issue an order finding that the Company's decision to repower its wind fleet is prudent and in the public interest, and approving the Company's proposals for ratemaking and the continued recovery of the replaced equipment. I also recommend that the Commission reject the parties' proposed conditions to approval and enable the Company to move forward with confidence as it embarks on a project of this magnitude on behalf of its customers.

Q. Does this conclude your supplemental rebuttal 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 Rebuttal Testimony of Timothy J. Hemstreet

April 2018

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 OF SUPPLEMENTAL REBUTTAL TESTIMONY

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

A. I respond to the testimony and recommendations of the Utah Division of Public Utilities ("DPU") witnesses Dr. Joni S. Zenger and Mr. Daniel Peaco.

Q. Please summarize your testimony.

A. I explain that the Public Service Commission of Utah ("Commission") should approve the Company's repowering project because it is in the public interest. The repowering project will provide substantial net benefits to Utah customers, and presents the lowest, reasonable-cost resource choice for the continued operation of the wind energy resources. As project implementation has continued, the Company's cost and performance estimates have become more certain, resulting in decreasing risk. As of this filing, the cost estimates are largely fixed and contractual provisions mitigate the risk that construction delays will compromise production tax credit ("PTC") eligibility. Also, engineering studies are complete, confirming the equipment selected for repowering and any necessary foundation work. The Company's cost estimate remains unchanged from its supplemental filing in February 2018, which is lower than the original cost estimate in the Company's initial filing.

The pace and timing of the Company's project implementation are consistent with projects of this scope and consistent with the preapproval process allowed by Utah law. Throughout this case, the Company has provided the parties and the Commission the most up-to-date information, based on changes in federal tax law, market conditions, and project implementation. In this way, the Company has ensured that the Commission and the parties have full and complete information on which to examine the merits of the repowering proposal.

Given the benefits of the wind repowering project, the DPU has not provided a sound rationale for its recommendation against the project. I address each of the DPU's objections and explain why none of them undermine the value proposition of wind repowering for customers.

REASONABLENESS OF FEBRUARY 2018 SUPPLEMENTAL FILING

Q. Dr. Zenger implies that the Company's supplemental filing on February 1, 2018, was improperly "an entirely new case with updated assumptions and new projected economic costs and benefits." (Zenger Resp., lines 126–128.) Was the Company's supplemental filing within the scope of the parties' agreement regarding the extension of the procedural schedule in this case?

A. Yes. The DPU supported Rocky Mountain Power's Unopposed Motion to Amend Procedural Schedule, filed on November 22, 2017. In that motion, the parties agreed that the Company "will file testimony that includes an updated economic analysis on a project-by-project basis." Parties expressly agreed that the Company's supplemental testimony would include "updates for known changes in wind repowering costs and performance," among other items.

My supplemental testimony included updates for known changes in wind repowering costs and performance based on continued contract negotiations, competitive market procurement activities, and engineering and design studies.

I updated cost estimates to reflect: (1) known changes in project costs as a result of completing final design of the Goodnoe Hills and Leaning Juniper projects, which resulted in changed costs to reflect foundation retrofits; (2) a changed turbine type at the Leaning Juniper facility; and (3) information from bids received for installation of the Vestas turbines. Overall, project costs increased from the Company's October 2017 filing by 1.7 percent.

Additionally, the Company updated its energy production/performance estimates to reflect: (1) the final design of the Leaning Juniper turbine type; (2) increased transmission interconnection capacity available for the Marengo facilities following the completion of transmission studies; and (3) four years of available historical data in the energy production estimates for all facilities using data that was previously unavailable. These updates resulted in a 0.1 percent reduction in the energy performance described in the Company's October 2017 filing.

The Company's February 2018 supplemental filing included the updates contemplated by the parties. A 1.7 percent change in project costs and 0.1 percent reduction in energy benefits in the Company's supplemental filing hardly reflects "an entirely new case."

Q. Dr. Zenger also suggests that some of the updates included in the February 2018 supplemental testimony "should have been filed in the Company's initial Application." (Zenger Resp., lines 120–122.) Would it have been possible to include any of the cost and performance updates from your supplemental testimony when the Company filed its initial application in June 2017?

A. No. Dr. Zenger never indicates which updates should have been provided in June 2017, but the updated cost and performance information included in my supplemental testimony was not known in June 2017.

Q. Dr. Zenger also claims that the Company's supplemental filing raised additional uncertainties because the DPU "discovered" that the Leaning Juniper and Goodnoe Hills facilities will require "unplanned" costs. (Zenger Resp., lines 214–216.) Was the supplemental filing the first time the Company disclosed that additional foundation studies were occurring for Leaning Juniper and Goodnoe Hills?

A. No. In my direct testimony filed in June 2017, I stated that "[f]or Leaning Juniper and Goodnoe Hills, foundation load evaluations have not yet been completed because those facilities are still under design review, which is expected to be completed by this fall." (Hemstreet Direct, lines 479–481.) Contrary to Dr. Zenger's implication that the Company was unaware of the possibility that additional foundation retrofits would be required, the Company disclosed the fact that these studies were ongoing in June 2017, which meant that the initial cost estimates were subject to change. The studies were completed on schedule and the costs are now included in the economic analysis.

Q. Dr. Zenger further claims that verification of the suitability of the foundations for repowering is "first order due diligence that the Company should have performed if it were planning wisely." (Zenger Resp., lines 225-226.) Do you agree?

A. No. My testimony has been clear that verifying the suitability of the foundations for the new turbines is a critical due diligence component, and that the Company would confirm the suitability of the foundations before executing contracts. (*See, e.g.*, Hemstreet Direct, lines 481–483.) The Company designed the overall schedule of the wind repowering project to minimize costs and risks. Fully consistent with that schedule, the Company has now verified that the foundations at all the facilities will be able to handle the loads of the new turbines.

Q. Is Dr. Zenger's claim that the Company acted too slowly on foundation verification inconsistent with her earlier criticism of the Company for engaging in preliminary work on the repowering project in advance of seeking preapproval?

A. Yes. In her direct testimony, Dr. Zenger faulted the Company for seeking preapproval of the repowering project while engaging in preliminary work on project implementation in advance of the Company's filing. (Zenger Direct, lines 88–95, 121–125.) It is inconsistent for Dr. Zenger to now fault the Company for not having done more preliminary implementation work for Leaning Juniper and Goodnoe Hills.

Q. Dr. Zenger next claims that "the Company's supplemental testimony shows that it might have to go to its parent company, Berkshire Hathaway Energy, to bail out PacifiCorp so that the Company will have an adequate supply of safe harbor equipment to still qualify for 100 percent of the PTCs." (Zenger Resp., lines 241–244.) Is this a fair characterization of the Company's earlier testimony?

A. No. In my supplemental direct testimony, I explained that all of the Company's facilities had more than adequate safe harbor equipment, noting the substantial cushion for each facility between the projected costs and the safe harbor requirements (allowing from between 65 percent and 5300 percent cost increase, depending on the facility). (Hemstreet Supp. Direct, lines 167–172.) As an additional customer safeguard, I also noted that the Company can use safe harbor equipment from its parent company, if necessary. My testimony demonstrated the Company's careful, conservative planning, and its risk mitigation options for compliance with safe harbor requirements. It is not clear how Dr. Zenger could interpret my testimony as suggesting that the Company might need a “bail out” to qualify for 100 percent of the PTCs.

RELIABILITY OF COST ESTIMATES

Q. Dr. Zenger states that “the Division has little confidence in the latest version of repowering costs and benefits provided in the Company’s supplemental filing” because the estimated benefits have “been so widely scattered.” (Zenger Resp., lines 62-65.) Have the estimated costs of the repowering project changed in a way that undermines their reliability?

A. No, the Company’s current cost estimate is $1.101 billion, a 2.4 percent decrease from the Company’s estimated project costs of $1.128 billion in its initial filing in June 2017. This is the same cost estimate contained in the Company’s supplemental filing in February 2018. The Company’s interim cost estimate in October 2017, was $1.083 billion, which reflected contracts negotiated with turbine suppliers after the initial filing, but did not yet include the costs of foundation retrofits later determined necessary at the Goodnoe Hills and Leaning Juniper facilities and updated turbine specifications for the Leaning Juniper facility.

Q. Dr. Zenger also claims that the total project costs are $1.337 billion as of February 1, 2018. (Zenger Resp., lines 140–143.) Is this correct?

A. No. As described in my supplemental direct testimony cited by Dr. Zenger, the estimated cost of the repowering project is $1.101 billion. The Company is unclear of the source of Dr. Zenger’s $1.337 billion figure. Dr. Zenger may be mistakenly referencing the cost estimate for a sensitivity case that the Company evaluated which includes additional energy collector system upgrade costs. The cost of that sensitivity case is $1.137 billion, however, not $1.337 billion.

The sensitivity includes the wind facility energy collector system upgrade costs necessary to allow the Wyoming facilities to interconnect to the transmission system at the full output capacity of the repowered turbines. The Company has not proposed to move forward with this option at this time, pending additional feasibility and economic review. To be clear, the base case repowering project cost estimate used in the economic analysis described by Mr. Rick T. Link does not include these network upgrade costs or associated benefits.

Q. Did the Company make any changes to its assumptions regarding run-rate capital expenditures or avoided capital costs anticipated from replacing impacted gearboxes or blades experiencing higher failure rates?

A. No. These assumptions have been unchanged throughout the case.

Q. Why have project costs and energy benefits changed during this proceeding?

A. Since the Company filed its request for resource approval, development and design of the repowering project has continued, as has the competitive solicitation and contract negotiation process. Project costs included in the Company's filings appropriately reflect the most recent information available. Thus, the February 2018 supplemental filing included the final design of the Leaning Juniper and Goodnoe Hills projects and their associated foundation review, and the changes in cost and energy production resulting from the ability of the Marengo facilities to operate at a higher repowered capacity under a revised interconnection agreement.

Throughout this case, the Company has incorporated into its analysis the most up-to-date wind turbine technology as engineering studies and equipment offerings have matured, and incorporated more competitive pricing achieved through negotiations with suppliers. Overall, these updates have been minor and have not materially affected the scope of the repowering project, or the Company's methodology in evaluating the costs of the projects. The Company reflected these updates to increase the accuracy and transparency of its filing.

Q. Has the Company provided detailed cost estimates for the project?

A. Yes. Through discovery, the Company has provided its detailed, confidential cost estimates including all of its assumptions regarding costs for equipment, equipment storage and maintenance, engineering, permitting, project management, property due diligence, site civil engineering and construction installation costs, construction management, contingency, construction standby time due to high wind conditions, applicable sales and property taxes, and allowance for funds used during construction ("AFUDC"). These cost estimates have also included all of the Company's assumptions regarding avoided capital costs due to repowering as well as changes to operations and maintenance costs expected as a result of the project.

Q. Does Dr. Zenger identify any specific component of the Company's cost estimate that she believes is unreliable?

A. No.

DECREASING RISK

Q. Dr. Zenger claims that customers' "uncertain benefits could materialize or disappear, depending on the suite of unknowns and risks that happen." (Zenger Resp., lines 164–166.) Does Dr. Zenger dispute the Company's evidence that it has successfully mitigated much of the risk associated with the repowering project?

A. No. As described in my past testimony, the Company has made significant progress mitigating customer risk:

- The Company has fully negotiated a turn-key agreement with GE for repowering the Wyoming wind projects. Thus, the costs for eight of the 12 repowering projects are now fixed.
- The GE contract includes a full service agreement, meaning that the costs for operations and maintenance [redacted] are fixed.
- The GE and Vestas contracts provide availability guarantees, making the production estimates more certain.
- The GE contract includes damages in the event that GE fails to meet the December 31, 2020, deadline for PTC eligibility that will effectively make customers whole.
- The Company has negotiated a turbine supply contract for the Oregon and Washington projects, meaning that the turbine costs of the remaining four projects are now fixed and the contract includes robust protections to guarantee on-time delivery.
- The Company has obtained the major necessary permits for 11 of the 12 repowering projects.
- Eleven of the 12 facilities that will be repowered are planned to be in service in 2019, more than a year before the December 31, 2020, PTC deadline. The only facility that will be repowered in 2020 is Dunlap, which will be repowered by GE subject to the contract provisions noted above that mitigate delay risk.
- The foundation design studies for Leaning Juniper and Goodnoe Hills are now complete and the costs for these upgrades are known.

Q. According to Dr. Zenger, DPU is skeptical of the Company's ability to find available contractors to install new wind turbine equipment and construct the projects that are being replaced with Vestas turbines on time and within budget before the December 31, 2020 deadline. (Zenger Resp., lines 184–202.) Do you believe this is a realistic risk?

A. No. The Company's request for proposals to install the Vestas turbines resulted in multiple, well-qualified wind energy construction contractors offering proposals to complete the installation and commissioning of the turbines in 2019, consistent with the Company's construction schedule. Thus these projects will be in-service one year before the December 31, 2020, deadline for qualifying for 100 percent of the federal production tax credit. The Company has evaluated the proposals received and is now in final contract negotiations with the construction contractors. While the Company expected to execute the Vestas installation contract by March 2018, the Company has extended the timeline slightly to align with the current schedule for regulatory review.

Q. Dr. Zenger claims that the Company has stated that it may have to stagger in-service dates to accommodate the availability of the Vestas installation contractor. (Zenger Resp., lines 196–198.) Is this accurate?

A. No. Dr. Zenger mischaracterizes my past testimony in this case. Although Dr. Zenger cites my testimony filed in the Wyoming repowering case (Docket No. 20000-519-EA-17), I filed substantively identical testimony in this case. (*See* Surrebuttal Testimony of Timothy J. Hemstreet, lines 96–115.) I opposed a condition recommended by Mr. Kevin Higgins, testifying on behalf of the Utah Association of Energy Users, which would have penalized the Company for any deviations from its filed construction schedule. I simply noted in my surrebuttal testimony that such a condition is unreasonable because the Company could deviate from its planned schedule for prudent reasons such as accommodating the availability of a construction contractor that offered the best price, while still meeting required project deadlines.

Q. Is the Company planning to alter its construction schedule?

A. No. The Company's construction schedule has not changed.

Q. Dr. Zenger states that there "is little assurance that there will not be a disruption or problem of some type with construction and installation of the new equipment." (Zenger Resp., lines 198–200.) Does Dr. Zenger raise any particular issues, technical concerns, or schedule risks that threaten the ability of the Company to complete the repowering project on its current construction schedule?

A. No. Dr. Zenger does not offer any explanation of the alleged risk. Notably, Dr. Zenger does not dispute my prior testimony describing the numerous customer protections in the repowering project contracts specifically designed to mitigate construction and installation risk.

Q. Dr. Zenger further states that if any of the projects "are one day late, the federal PTC may either be lost, or drop to 80 percent instead of 100 percent, increasing the risk that the projects will be uneconomic for customers." (Zenger Resp., lines 200–202.) Is this statement accurate?

A. No. Dr. Zenger implies that the Company's construction schedule calls for the repowering project to be completed on December 31, 2020, which is not true. While the repowered turbines must be in-service by December 31, 2020, to qualify for the full value of the PTC, the Company has not designed its project schedule to achieve commercial operations of the repowered facilities on December 31, 2020—the day of the deadline. Rather, the Company's construction schedule anticipates completion of all but one project in 2019. Thus with 11 of the 12 facilities planned to be in service on or before November 1, 2019, those facilities would need to be more than 427 days late—not a single day late—for PTC qualification to be at risk due to schedule delay. And the twelfth facility, the Dunlap project, would need to be one full month late, not one day late to be at risk. The schedule for repowering Dunlap is designed to maximize the current PTCs that are generated by that facility and therefore it will be the final project repowered before the December 31, 2020, deadline. As discussed above and in-depth in my rebuttal testimony, the risk of lost PTCs for the GE projects—such as Dunlap—due to schedule delays has been contractually mitigated through the GE retrofit contract, under which GE will pay liquidated damages that represent the full costs of any turbine that is not repowered by December 31, 2020.

Q. During the original construction of the wind facilities proposed to be repowered, did the Company ever experience construction delays that resulted in commissioning of the facilities being delayed more than one year from the planned in-service date or failing to qualify for PTCs?

A. No. The Company has never experienced construction delays of a duration that would be necessary to threaten PTC qualification in this case and all of its projects achieved full PTC benefits for customers.

Q. Mr. Peaco acknowledges that the Company has provided additional evidence that it is well-positioned to meet the PTC safe harbor requirements. Mr. Peaco also claims, however, that "the PTC qualification risks that remain are largely within the Company's control to manage, but, as in the prior testimony, the Company is not agreeing to assume any of the remaining risk." (Peaco Resp., lines 579–586.) Is this accurate?

A. No. The Company has agreed to fully assume all PTC risks associated with factors within its control, as described in "prior testimony" (Crane Rebuttal, lines 103–109.) and reiterated in the supplemental rebuttal testimony of Mr. Gary W. Hoogeveen. Mr. Peaco cites this commitment, but does not explain what risks remain uncovered. (Peaco Resp. n. 40.) Moverover, Mr. Peaco does not dispute my testimony that the Company would have to experience huge cost overruns for non-fixed costs (between 65 and 5,300 percent) to jeopardize the five-percent PTC safe harbor requirement. (Hemstreet Supp. Conf. Table 1.)

Q. Mr. Peaco reiterates his claim that there is risk that the repowered projects will have shorter useful lives than assumed in the Company's analysis, and that the Company provided no additional evidence addressing this risk. (Peaco Resp., lines 625–626.) What is the basis for Mr. Peaco's concern?

A. Mr. Peaco contends that there is risk that the economic life of the repowered assets could be less than their 30-year book life, and that the existing assets could potentially stay in service longer than the 30 years assumed in the Company's economic analysis. He believes that this poses a risk to the economic benefits of the projects, given the substantial incremental energy production available from the repowered facilities after the original assets would have retired.

Q. Do you believe this is a significant concern?

A. No. As Mr. Peaco noted in his earlier testimony (Peaco Direct, lines 862–863), the Company's assumptions related to asset life are consistent between the existing assets and the repowered assets. Additionally, the risk that the economic life of the wind assets may not match their book lives is a risk faced by both the existing wind assets and the repowered assets. The potential also exists that the existing assets could have an economic life of fewer than 30 years and that the repowered assets—incorporating the latest wind turbine technology—could have an asset life greater than 30 years. In either situation, the repowering project results in increased benefits compared to the status quo case.

Q. Does Mr. Peaco offer any proposal for how this "risk" could be mitigated by the Company, or even evaluated on a going-forward basis?

A. No.

Q. Mr. Peaco has also contended that PTC qualification for some projects could be at risk due to failing the 80/20 rule if, for example, the value of the retained assets were to increase by 10 percent. (Peaco Surrebuttal, lines 459–465.) Is that accurate?

A. No. As shown in Table 1 below, Mr. Peaco's statement is incorrect. Under Mr. Peaco's hypothetical, only seven turbines at the Glenrock III project constructed on a specific foundation type that required deep dynamic compaction would fail, not the entire project. Further, the repowering costs would still be sufficient for 588 of the 595 turbines proposed for repowering, and the margins above the requirement are substantial even in this hypothetical situation.

Confidential Table 1: 80/20 Rule Spending Requirements by Project Assuming 10 Percent Increase in Ernst & Young Preliminary Fair Market Valuation

Facility Name	Turbine Foundation Type	# of Turbines	110% of Ernst & Young Preliminary FMV of Retained Components Per Turbine 12/31/2018 ($000s)	Minimum Threshold of New Turbine Costs Required ($000s)	Qualifying Repowering Costs Per Turbine ($000s)	New Turbine Costs in Excess of Requirement ($000s)
Goodnoe Hills	Standard	47	[redacted]	[redacted]	[redacted]	[redacted]
Marengo I	Standard	78	[redacted]	[redacted]	[redacted]	[redacted]
Leaning Juniper	Standard	67	[redacted]	[redacted]	[redacted]	[redacted]
Glenrock I	Standard	58	[redacted]	[redacted]	[redacted]	[redacted]
Marengo II	Standard	39	[redacted]	[redacted]	[redacted]	[redacted]
McFadden Ridge	Standard	19	[redacted]	[redacted]	[redacted]	[redacted]
Rolling Hills	Standard	42	[redacted]	[redacted]	[redacted]	[redacted]
Seven Mile Hill I	Standard	57	[redacted]	[redacted]	[redacted]	[redacted]
Seven Mile Hill I	Dynamic	9	[redacted]	[redacted]	[redacted]	[redacted]
Glenrock III	Standard	13	[redacted]	[redacted]	[redacted]	[redacted]
High Plains	Standard	66	[redacted]	[redacted]	[redacted]	[redacted]
Seven Mile Hill II	Standard	13	[redacted]	[redacted]	[redacted]	[redacted]
Dunlap	Standard	74	[redacted]	[redacted]	[redacted]	[redacted]
Rolling Hills	Dynamic	6	[redacted]	[redacted]	[redacted]	[redacted]
Glenrock III	Dynamic	7	[redacted]	[redacted]	[redacted]	[redacted]

Q. What do you conclude about the risk of not qualifying for PTCs due to failure to meet the 80/20 test?

A. The risk of not qualifying for PTCs due to failure to meet the 80/20 test is low. Mr. Peaco raised this risk in his surrebuttal testimony filed in November 2017, in which he also noted that he had not reviewed the Ernst & Young preliminary valuation reports in detail. Having now had several additional months to review those reports, Mr. Peaco has not raised any additional concerns in his response testimony about those reports, the valuation methodology upon which they are based, or the ability of the repowered turbines to meet the 80/20 test. Further, given the methodology described in the valuation reports—which relies upon a cost approach to value the retained components—Mr. Peaco has provided no support to the risk he previously identified that the valuation could increase 10 percent. Given the cost approach of the valuation methodology, and the fact that the Company's costs for the wind facilities is known and fixed, there is no reasonable basis to conclude that the valuation could increase 10 percent as Mr. Peaco speculated.

SUFFICIENCY OF INFORMATION PROVIDED WITH THE COMPANY'S APPLICATION AND IN DISCOVERY

Q. Dr. Zenger faults the Company for filing its case "before much due diligence and preparatory work was completed." (Zenger Resp., lines 290–291.) Do you agree with this assessment?

A. No. Before its initial filing in June 2017, the Company had completed engineering design and review for 10 of the 12 projects, including foundation suitability assessments. The Company had verified the suitability of the repowering equipment at those 10 facility locations, obtained energy production estimates for all the projects using best available information, and the Company had filed requests to modify its interconnection agreements to reflect the new capacity of the repowered facilities. The Company had also made substantial progress in negotiating its contracts to execute the repowering project-and has now made the final form of turbine supply and retrofit contracts available. As I note above, it is ironic that Dr. Zenger's direct testimony faulted the Company for doing too much work to implement repowering before filing its application, and now Dr. Zenger faults the Company for doing too little.

The Company has provided an extraordinary amount of information in its filings, testimony, and discovery responses, completed a significant amount of engineering and technical analysis before filing its application, and made this engineering and due diligence information available to all parties. As additional engineering work has been completed, the Company has filed supplemental data responses to provide the latest information available. The Company has laid out the technical work that has been completed (e.g., turbine suitability evaluations, energy production assessments, foundation suitability analyses), and has described the further technical due diligence that will be obtained, such as the third-party design certification.

Moreover, it is unclear what additional due diligence and preparatory work Dr. Zenger believes the Company should have completed before filing. Dr. Zenger provides a single example of "work and analysis that remains outstanding"—the third-party design certifications. (Zenger Resp., lines 307–348.) But as the Company explained in discovery, third-party design certification is provided pursuant to the turbine supply and retrofit contracts that the Company has not yet executed. Thus, Dr. Zenger faults the Company for having not obtained deliverables from the turbine suppliers pursuant to contracts the Company has not yet executed.

Q. Dr. Zenger further suggests that requests for approval of a voluntary resource decision related to wind projects should strictly comply with the filing requirements developed after the conclusion of Docket No. 09-035-23 for recovery of wind project costs. (Zenger Resp., lines 365–380.) How do you respond?

A. I disagree that the Company's request was lacking in detail, and I disagree that the additional information Dr. Zenger requests applies to a voluntary request for approval of a resource decision like repowering. As I understand it, the issue in Docket No. 09-

035-23 involved how to present sufficient detail on wind project costs to allow for a meaningful prudence review in a general rate case. Thus, the information that the Company agreed to provide includes information like the turbine purchase price, turbine purchase date, final turbine placement, pricing and terms for the land lease associated with a wind project, and description of change orders occurring during project implementation. *See* Exhibit 1.2-RESP. Reviewing the information the DPU wants indicates that much of it is known only after a wind project is completed and placed in-service. It makes little sense to require an application for preapproval to include this information when, by definition, it does not yet exist. In addition, very little of the information that Dr. Zenger claims is lacking from the Company's filing is included in the requirements set forth in Exhibit 1.2-RESP.

Q. Does Dr. Zenger point to any other specific items that *are* included in Exhibit 1.2-RESP that DPU has not been able to review?

A. No.

SUFFICIENCY OF THE DATA USED FOR ENERGY PRODUCTION ESTIMATES

Q. Dr. Zenger claims that the Company's energy production estimates are "seemingly supported by relatively little data." (Zenger Resp., lines 209–212.) Do you agree with this assessment?

A. I strongly disagree, and note that Dr. Zenger offers no basis for her claim. The Company's estimates are based on energy production data for every single turbine at each facility for every 10-minute interval over a four-year period. I am not aware of any more accurate method—nor is the Company's engineering consultant Black & Veatch—that could be used to forecast the increased energy production expected from repowering. Dr. Zenger herself proposes no alternative approach.

Q. Mr. Peaco states that there is uncertainty in the Company's energy production estimates because only four years of operating history was used to assess the expected increase in energy production. (Peaco Resp., lines 620–622.) Do you believe that four years of historical data is sufficient to assess long-term energy increases with repowering?

A. Yes. The Company's estimates of the increased energy production from repowering are based on four years of historical operations data from 2013–2016, incorporating the actual production history of every single wind turbine at the facilities that will be repowered. The Company used the 2013–2016 historical period because this allows energy production to be assessed over a long enough period to cover variability in wind conditions, and thus annual generation, and align with long-term averages.

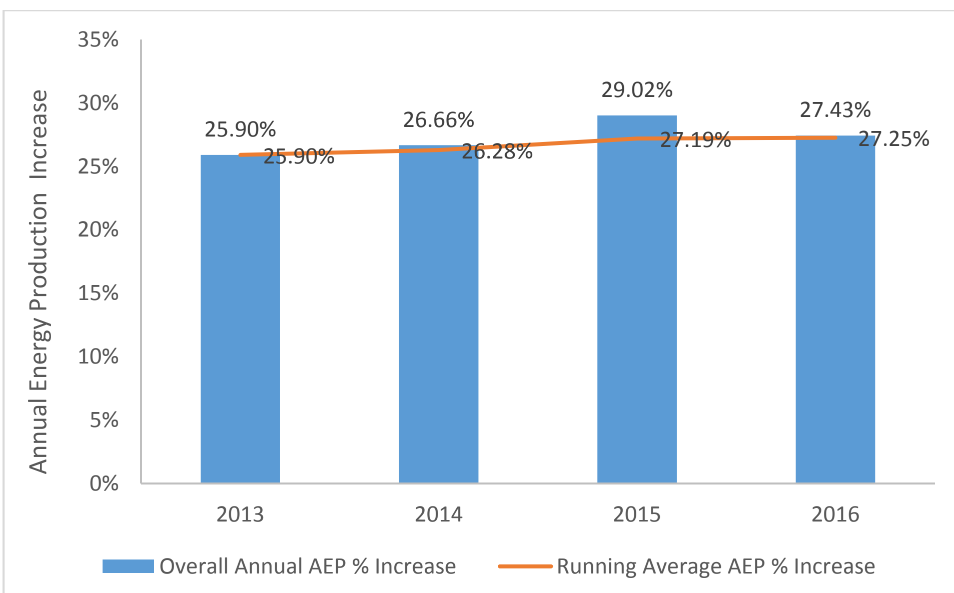
As shown in Table 2, the generation from this four-year period reflects a range of year types from below-average winds to above-average winds. In all, the generation from this 2013–2016 period reflects 98.7 percent of the long-term average generation from the facilities, indicating the energy production estimates developed from this period should be representative of those expected over the long term.

Table 2: Existing Wind Project Generation by Year

Year	Annual Generation (MWh)	% of Long Term Avg. Generation
2013	3,002,312	104.6%
2014	2,936,207	102.3%
2015	2,508,055	87.4%
2016	2,878,792	100.3%
2013-2016 Average	2,831,341	98.7%
Existing Long Term Average Generation	2,869,016	

Additionally, the operational regime of the wind projects in this recent history is most representative of current facility operations, as compared to earlier years. For example, the first full year of operational curtailments to address avian impacts began in 2013 at Seven Mile Hill I, Seven Mile Hill II, Glenrock I, Glenrock III and Rolling Hills. Further, the Company joined the California Independent System Operator ("CAISO") energy imbalance market ("EIM") on November 1, 2014, which has impacted the economic dispatch of the Company's wind projects relative to the marginal cost of other resources in the EIM market. Finally, Figure 1 also shows that there is very little inter-annual variability in the estimated overall annual energy production increase associated with repowering. That is, the annual energy production increase is relatively insensitive to the number of years of data used to generate the estimate.

Figure 1: Variability in Annual Energy Production ("AEP") Increase by Year



Q. Mr. Peaco faults the Company for not separately analyzing the economic benefits of repowering only turbines that are likely to experience failed components. (Peaco Resp., lines 445–448.) Can you explain why the Company has not prepared this analysis?

A. First, the analysis Mr. Peaco suggests presents many challenges as it would be inconsistent with negotiated contracts with turbine suppliers to repower all turbines at its facilities that can be repowered and qualify for PTCs.

Second, repowering certain turbines but not others at the project sites would implicate the service and maintenance agreements that have been negotiated for these sites.

Third, for project sites [redacted].

Fourth, repowering only certain turbines at a facility—and retiring the turbines not repowered earlier than those that are repowered—may impact the land rights under which the facilities operate. The landowners may consider early decommissioning of some turbines and not others on their property as a breach of the lease agreements because it frustrates their purpose in the wind energy lease to maximize royalty payments from wind energy production.

Fifth, at the end of the useful lives of the original equipment that is not repowered, it would also be more challenging—and perhaps infeasible—to repower the site because some turbine locations would continue generating for another 10 years, while others would cease operation. Given the larger size of modern turbine rotors and the greater spacing required between them, it would not be easy to integrate newer turbines into the projects. Because of these unknowns—and unknown costs even if these issues could be overcome—it would be pure speculation to develop an estimate of the costs and benefits of selectively repowered turbines over a new 30-year asset life as Mr. Peaco describes.

Q. Are there problems with Mr. Peaco's analysis in which he attempts to evaluate repowering benefits that may be attained by focusing only on turbines that would experience the most avoided capital expenditure if repowered?

A. Yes. Mr. Peaco's analysis ignores the fundamental nature of the optimization model used to support the Company's analysis by simplifying the results and parsing them in a static spreadsheet. Mr. Peaco's analysis comparing the economics of repowering turbines with impacted and non-impacted gearboxes at the Seven Mile Hill I and Leaning Juniper facilities does not acknowledge the fact that by altering the number of turbines repowered at a facility, the capacity factor, shape, total nameplate capacity, and generation output of the repowered facility also change.

Q. Mr. Peaco states that many of the "projects and turbines included in the repowering proposal do not have potential to deliver high likelihood of benefits." (Peaco Resp., lines 535–537.) Do you agree?

A. No. Mr. Peaco performed an analysis looking at only two facilities (Seven Mile Hill I and Leaning Juniper) to attempt to determine the relative benefits of repowering turbines that had impacted gearboxes. The analysis evaluated those facilities under the most conservative of nine price-policy scenarios in which the benefits of repowering would be the lowest. Additionally, the analysis did not demonstrate that repowering non-impacted gearboxes was not economic, only that repowering turbines facing expenditures to address an impacted gearbox is more favorable, as would be expected. The Company's analysis shows that repowering all turbines, including those that do not have a problem gearbox, creates net benefits.

Q. Mr. Peaco recommends the Company consider a revised program proposal that eliminates at least six of what he believes are the least attractive sites and limits the repowering to those turbines that have problematic gearbox equipment. (Peaco Resp., lines 670–690). Do you agree with this recommendation?

A. No. Reducing the scope of the repowering projects would deny customers the full net benefits of the project. Although the different projects offer varying levels of net benefits, they all still provide a net benefit, nevertheless. Furthermore, the analysis provided by Mr. Peaco does not demonstrate that it is uneconomic to repower the turbines with non-impacted gearboxes.

PROJECT NEED

Q. Dr. Zenger states that "considering the risk that the Company is asking ratepayers to bear, the short- and long-term impacts, and the fact that the new equipment is not needed for reliability or other purposes, the Division continues to find that the Company's proposal to repower is not prudent or in the public interest." (Zenger Resp., lines 71–74.) Do you agree with this assessment?

A. No. As outlined above and in my earlier testimony, the risks of the repowering project are clearly outweighed by the net benefits to customers. In addition, I fundamentally disagree that the new equipment is not needed for reliability purposes. My direct testimony spoke of the enhanced ability of the repowering turbines to provide voltage and inertial support to the transmission system in Wyoming. The Company has also provided studies to parties through discovery indicating a need for additional reactive power on the Company's transmission system that will be provided by the repowered facilities. Finally, as described by Mr. Link, the repowering project was included as a fundamental element of the Company's least-cost, least-risk resource portfolio in the 2017 IRP.

Q. Does this conclude your supplemental rebuttal testimony?

A. Yes.

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

Supplemental Rebuttal Testimony of Rick T. Link

April 2018

Q. Are you the same Rick T. Link who previously provided testimony in this case on behalf of Rocky Mountain Power, a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. I rebut challenges to PacifiCorp's economic analysis raised in the response testimonies of the Utah Division of Public Utilities ("DPU") witnesses Dr. Joni Zenger and Mr. Daniel Peaco; Office of Consumer Services ("OCS") witness Mr. Philip Hayet; and the Utah Association of Energy Users ("UAE") witness Mr. Kevin C. Higgins.

Q. Please summarize your supplemental rebuttal testimony.

A. My supplemental rebuttal testimony responds to concerns raised by parties in their response testimony, including criticisms of PacifiCorp's modeling assumptions and methodologies. My supplemental rebuttal demonstrates that:

- PacifiCorp's economic analysis summarized in my supplemental direct testimony was updated in accordance with its unopposed motion to amend the procedural schedule filed November 22, 2017.
- PacifiCorp filed a robust application and has provided extensive testimony, exhibits, and work papers with each filing to explain, demonstrate, and support its economic analysis.
- PacifiCorp improved its 20-year economic analysis by considering nominal production tax credit ("PTC") benefits and levelized capital revenue requirement costs, which conforms the treatment of PTCs to the treatment of other costs and benefits that are not actually spread over the life of the asset and appropriately weights the contribution of these elements in present value net-benefit calculations.
- Despite claims to the contrary, the independent analyses prepared by parties and summarized in their response testimony, while flawed, only validate and affirm the primary conclusions summarized in my supplemental direct testimony:

  1) 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;
>
> 2) 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.
>
> 3) these net and gross customer benefits are conservative, as they do not account for potential incremental benefits from renewable energy credits and understate the potential benefits from reduced carbon dioxide ("CO_2") emissions.
>
> 4) 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 PTCs, but does not account for the value of incremental energy output that will increase significantly beyond 2036.

ECONOMIC ANALYSIS ASSUMPTIONS

Q. In its supplemental direct filing, did PacifiCorp update its economic analysis supporting the wind repowering project?

A. Yes. My supplemental direct testimony summarized an updated economic analysis to reflect: (1) updated cost-and-performance assumptions for the wind repowering project; (2) more current price-policy scenario assumptions; and (3) recent changes in the federal tax rate for corporations.

Q. Dr. Zenger asserts that PacifiCorp "basically filed an entirely new case" when it should have only updated its economic analysis to reflect the recent change in federal tax legislation (Zenger Response, lines 124–128.) Do you agree?

A. No. In the unopposed motion to amend the procedural schedule filed by the company on November 22, 2017, parties authorized the company to represent that they supported the motion and agreed, among other things, that the company would file supplemental testimony that includes an updated economic analysis to reflect specific assumption updates. Unopposed Motion to Amend Procedural Schedule, ¶¶ 2, 4 (Nov. 22, 2017).

Q. Was DPU among the parties that authorized the company to represent they had agreed, among other things, that the company would file an updated economic analysis?

A. Yes.

Q. What specific assumptions did DPU and other parties agree should be reflected in the supplemental filing?

A. The parties agreed that the supplemental economic analysis would be performed on a project-by-project basis and be updated to reflect: 1) any determinative actions by Congress on tax reform; 2) official forward price curves ("OFPCs") effective as of January 1, 2018; 3) scenario analysis for, at minimum, the low natural gas, zero CO_2 and medium natural gas, medium CO_2 price-policy scenarios; and 4) updates for known changes to cost in wind repowering costs and performance, and projected changes in CO_2 costs. Unopposed Motion to Amend Procedural Schedule, ¶ 4.

Q. Did PacifiCorp's updated economic analysis summarized in your supplemental direct testimony reflect the specific assumption updates listed in the unopposed motion?

A. Yes. In fact, had PacifiCorp updated its economic analysis to only reflect changes to federal tax legislation, as Dr. Zenger asserts should have been the case, the company would not have satisfied its agreement with DPU and other parties. PacifiCorp's supplemental direct filing simply met the commitments outlined in the company's unopposed motion.

Q. Do other parties find that it was reasonable for PacifiCorp to update certain assumptions in the economic analysis described in your supplemental direct testimony?

A. Yes. Mr. Hayet states in his response testimony that he found it reasonable that PacifiCorp lowered its natural gas forecast. (Hayet Response, lines 360–369.)

Q. Dr. Zenger claims that PacifiCorp filed very little upfront in its application, that DPU had to conduct its analysis through discovery, and that this was compounded by the company's "failure to include discussion of these project in the 2017 IRP workshops" (Zenger Response, lines 279–289.) Is this accurate?

A. No. PacifiCorp filed a robust application and has provided extensive testimony, exhibits, and work papers with each filing to explain, demonstrate, and support its economic analysis. PacifiCorp also participated in the wind repowering technical conference on August 30, 2017, to present and address questions from parties related to the company's wind repowering application. During the confidential session of this technical workshop, I personally walked the parties through the extensive set of work papers that supported the economic analysis summarized in my direct testimony.

Dr. Zenger's claim that the wind repowering project was not discussed in 2017 Integrated Resource Plan ("IRP") workshops is simply not accurate. In February 2017, PacifiCorp finalized its IRP analysis of the wind repowering project. The scope of the wind repowering project and the accompanying economic analysis was discussed at a public input meeting held in early March 2017, before filing the 2017 IRP in early April 2017. The wind repowering project was also discussed in the 2017 IRP. Moreover, after the 2017 IRP was filed and before the wind repowering application was filed, PacifiCorp met with IRP stakeholders to discuss the wind repowering project; the meeting with DPU took place on May 10, 2017.

Q. Dr. Zenger states that "much of the early work in this case was wasted as analyses, assumptions and projections changed." (Zenger Response, lines 297–299.) How do you respond?

A. PacifiCorp updated its assumptions and projections to ensure that its economic analysis remains current. These updates are necessary to confirm that the wind repowering project will deliver customer benefits, despite changes to federal tax law and market forces that are beyond PacifiCorp's control. Moreover, all of the modeling updates that are described in my supplemental direct testimony conform to the updates that DPU and other parties agreed should be made. To facilitate the parties' review of PacifiCorp's filings, the company has been transparent, has thoroughly documented and explained its updated assumptions, and has provided extensive work papers that support all of the economic analyses presented in testimony and accompanying exhibits.

Q. Mr. Hayet testifies that updated medium CO_2 price assumptions reduce the CO_2 emission benefits from the wind repowering project and that it is possible that there will be no CO_2 benefits, particularly within the 20-year study period. (Hayet Response, lines 370–385.) How do you respond?

A. As described in my supplemental direct testimony, PacifiCorp updated its CO_2 price assumptions to align with the most current third-party projections. Relative to the CO_2 price assumptions applied in the economic analysis summarized in my direct and rebuttal testimony, the updated CO_2 price assumptions applied in the economic analysis summarized in my supplemental direct testimony begins in 2030 (five years later) and are slightly lower. Mr. Hayet's observation that the benefits from CO_2 emission reductions have dropped is accurate. However, as noted in my supplemental direct testimony, PacifiCorp inadvertently applied these assumptions in 2012 real dollars instead of in nominal dollars. Consequently, the CO_2 emission reduction benefits in the six price-policy scenarios that use a CO_2 price assumption are conservative.

I also agree with Mr. Hayet that it is possible there may not be a direct cost associated with CO_2 emissions within the 20-year study period, and consequently, it is possible there may not be any direct CO_2 emission benefits from the wind repowering project. This is precisely why the company included a set of price-policy scenarios that do not assume a CO_2 price. However, I do not agree with Mr. Hayet's assertion that the five-year shift in the assumed start year for base case CO_2 price assumptions justifies an expectation that CO_2 price assumptions will continue to be pushed out in future studies. In fact, I believe it is more likely than not that there will be some form of state or federal CO_2 policy that imputes either a direct or indirect cost on CO_2 emissions.

LEVELIZED PTCs

Q. Is the total PTC benefit associated with the wind repowering project over 10 years substantial?

A. Yes. Over 10 years, the total PTC benefit sums to approximately $1.2 billion.

Q. Mr. Hayet states that the change in treatment of PTCs in PacifiCorp's analysis did not strictly comply with the Commission's amended scheduling order and implies that the company may be "doing everything it can to ensure the projects appear to be economic in every analysis performed." (Hayet Response, lines 87–103.) Mr. Higgins makes similar claims. (Higgins Response, lines 282–285.) Do you agree?

A. No. PacifiCorp updated its economic analysis consistent with the agreement set forth in its unopposed motion to amend the procedural schedule. As described in my testimony in Docket No. 17-035-40, PacifiCorp refined its treatment of PTCs when analyzing bids offered into the 2017R Request for Proposals to ensure that bid selections would appropriately account for nominal PTC benefits, which is how PTCs are treated in rates. For this same reason, and to maintain consistency, PacifiCorp applied this more accurate treatment of PTCs in its updated economic analysis of the proposed wind repowering project. This more accurate treatment of PTC benefits was *not* implemented to ensure that projects appear to be economic in every analysis. The updated economic analysis of the wind repowering project simply demonstrates that these investments are economic in all price-policy scenarios and will provide substantial customer benefits.

Q. Mr. Higgins explains that the present-value results from PacifiCorp's 20-year IRP economic analysis included with the company's supplemental direct filing are not directly comparable to the results included in the company's direct and rebuttal filings. (Higgins Response, lines 166–169.) Do you agree with this assessment?

A. Yes. In my supplemental direct testimony, I explained that the updated economic analysis reflects a change in how the company applied federal PTC benefits in its 20-year analysis. (Link Supplemental Direct, lines 185–192.) When summarizing the results of the updated 20-year economic analysis, I explicitly noted that the reported present-value net benefits are higher than those summarized in my rebuttal testimony because the updated results were influenced by the use of nominal PTCs instead of levelized PTCs. (Link Supplemental Direct, lines 344–347.)

Q. Mr. Peaco claims that the nominal treatment of PTCs has the potential to bias model results and does not provide a reasonable estimate of the benefits of the repowering project. (Peaco Response, lines 204–209.) Mr. Higgins and Mr. Hayet similarly note that the treatment of capital costs continues to be measured on a real-levelized basis. (Higgins Response, lines 279–282; Hayet Response, lines 238–277.) How do you respond?

A. The rationale for applying PTC benefits on a nominal basis is reasonable and necessary to align the 20-year economic analysis with how PTC benefits will flow through to customers in rates. It is appropriate that the company continue to apply revenue requirement associated with capital costs on a levelized basis, because 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. In contrast, PTC benefits will flow to customers during the first 10 years after the new equipment is installed at the proposed wind facilities. Consequently, the timing of the PTC benefits should be appropriately weighted and accounted for in the present-value calculation of net benefits.

This is consistent with how PacifiCorp has historically conducted its economic analysis of specific resource decisions, where it has treated costs that are not spread over the life of an asset on a nominal basis. Typically this means that capital costs are levelized, while other costs like run-rate operating costs, are nominal. The refined modeling used in the updated economic analysis is more accurate as it conforms the treatment of PTCs to the treatment of other costs and benefits that are not actually spread over the life of the asset.

Q. Mr. Higgins claims that to maintain any reasonable nexus with the IRP process, the benefits of the repowering project should be measured using the same valuation methods that were applied in the IRP and that the change to nominal treatment of PTC benefits causes the wind repowering proposal to depart from the IRP framework. (Higgins Response, lines 395–472.) Do you agree?

A. No. While it is true that PacifiCorp levelized PTC benefits in its 2017 IRP, the company has since improved its methodology to more accurately reflect how PTC benefits will flow into customer rates, which in turn, provides a more accurate representation of the net benefits associated with the wind repowering project. By accounting for PTC benefits on a nominal basis, present-value calculations of customer benefits appropriately weight the front-end loaded PTC benefits resulting in a more accurate representation of present-value net benefits. This means that the present-value economic benefits of the wind repowering project that are presented in the 2017 IRP are understated, and this is why PacifiCorp intends to adopt the more accurate nominal treatment of PTCs in future IRPs.

Mr. Higgins's position of maintaining consistency with the IRP might have merit if a modeling improvement were later adopted that demonstrates a resource decision identified in the IRP should not have been an element of the least-cost, least-risk preferred portfolio. However, that is not the case in this instance. PacifiCorp's improved modeling approach simply demonstrates that, all else equal, the wind repowering project provides more present-value customer benefits than was originally estimated in the 2017 IRP, which only solidifies its inclusion as an element of the company's least-cost, least risk resource plan.

Q. Mr. Higgins calculates the 20-year wind repowering benefits using nominal capital costs with nominal PTCs and concludes that the benefits in each price-policy scenario drop by $39 million. (Higgins Response, lines 497–509.) How do you respond?

A. On its face, it is perfectly rational to consider nominal revenue requirement for capital investments over any time period. However, for the reasons described in my direct testimony (Link Direct, lines 412–431), it is not appropriate to include nominal revenue requirement from capital investments for assets having a depreciable life that extends beyond the 20-year IRP study period in *present-value* calculations. Mr. Higgins states that the 20-year analysis, with the application of levelized capital costs, understates revenue requirement and true rate impacts (Higgins Response, lines 478–480), and he inappropriately estimates the impact of this assumption in single present-value figure. Mr. Higgins fails to recognize that the present-value results from the IRP models are intended to assess the relative difference in system costs among different resource portfolios over a 20-year planning time frame. The present-value results from the IRP models are not configured to forecast annual rate impacts between different resource portfolios.

Throughout this proceeding, my testimony has presented an annual revenue requirement analysis of the wind repowering project to specifically address directional rate implications in nine different price-policy scenarios. In this analysis, it is appropriate to consider the nominal revenue requirement from capital costs in the present-value calculations because it spans the full 30-year life of the repowered wind facilities. Importantly, as summarized in my supplemental direct testimony, these present-value results demonstrate that the wind repowering project is expected to produce net customer benefits in all nine scenarios (Link Supplemental Direct, lines 381–398), that these results are conservative (Link Supplemental Direct, lines 399–314), and that under a base-case view, these benefits are expected to occur over both the near and long term. (Link Supplemental Direct, lines 414–435.)

Importantly, even if one were to assume that Mr. Higgins's present-value calculation showing a $39 million reduction in PacifiCorp's present-value net benefits is valid for the 20-year IRP analysis—and to be clear, the company is not saying this calculation is valid—the wind repowering project still generates net customer benefits in all nine price-policy scenarios. Mr. Higgins's own analysis shows that even in the lowest gross-benefit scenario that applies low natural gas and zero CO_2 price assumptions, the wind repowering project still generates between $103 million and $121 million in present-value net benefits for customers. (Higgins Response, Table KCH-7-RE.)

Q. Mr. Hayet concludes that while PacifiCorp's new modeling approach ensures that the entirety of PTC benefits will be captured in the 20-year economic evaluation, some of the repowering tax costs and other capital-related revenue requirements will be excluded from that 20-year analysis. (Hayet Response, lines 234–237.) Do you agree?

A. No. In the 20-year IRP analysis, application of nominal PTC benefits and levelized capital revenue requirement appropriately reflects the relative difference in the present-value benefits and costs from a resource portfolio that includes the wind repowering project with a resource portfolio that does not include the wind repowering project. Interestingly, in asserting that certain costs are not captured in PacifiCorp's 20-year IRP analysis, Mr. Hayet fails to mention that this analysis also does not capture any benefits that the wind repowering project will generate beyond the 20-year time frame.

Q. Mr. Hayet asserts that through the nominal treatment of PTCs and levelized treatment of capital costs, the company maximized the inclusion of PTC benefits but minimized the inclusion of capital revenue requirements in its economic analysis, thereby increasing the benefits of each project. (Hayet Response, lines 258–359.) Is this accurate?

A. No. As discussed above, PacifiCorp's approach to calculating the change in present-value system costs between resource portfolios with and without the wind repowering project in the 20-year IRP analysis is appropriate. It is only appropriate to include capital revenue requirement on a nominal basis in present-value calculations when those calculations cover the full life of the repowered wind facilities. That analysis is included in my supplemental direct testimony and demonstrates that the wind repowering project is expected to generate net customer benefits in all nine price-policy scenarios.

PROJECT-BY-PROJECT ANALYSIS

Q. Mr. Hayet presents an alternative 20-year project-by-project analysis that treats both capital-related revenue requirement and PTCs on a nominal basis. (Hayet Response, lines 545–550.) Is Mr. Hayet's alternative analysis more accurate than the approach used in PacifiCorp's economic analysis?

A. No. Mr. Hayet justifies his alternative 20-year project-by-project analysis as superior because it relies on a representation of capital revenue requirement he claims is consistent with the representation of PTCs. He also states that this alternative is consistent with the way costs and benefits flow through to customer rates. (Hayet Response, lines 560–563.)

One of Mr. Hayet's fundamental assumptions—that revenue requirement from capital and PTCs should be calculated on the same basis when performing present-value calculations in the 20-year IRP analysis—is flawed. As I have already discussed, it is not appropriate to calculate present-value costs from nominal capital revenue requirement when the study period is shorter than the life of the asset. In contrast, it is appropriate to consider nominal PTC benefits in the 20-year IRP analysis because these benefits will be realized within the 20-year timeframe of the study. Consequently, PacifiCorp's 20-year IRP analysis appropriately weights these front-end loaded benefits without disproportionately weighting capital costs in the present-value calculations. For this reason, the company's approach provides the most accurate representation of overall customer net benefits when calculated over the 20-year planning period used in the 2017 IRP.

Mr. Hayet also states that his alternative methodology is consistent with how costs and benefits flow through to customer rates. (Hayet Response, lines 560–563.) Mr. Hayet fails to recognize that the company's annual revenue requirement analysis is consistent with how costs and benefits flow through to customer rates, that it applies both capital revenue requirement and PTCs on a consistent (nominal) basis, and because the term of this annual revenue requirement analysis covers the full life of the repowered wind facilities, the present-value results of this analysis are valid. In short, Mr. Hayet fails to recognize that PacifiCorp has already performed an economic analysis that meets the stated goals of his proposed alternative methodology. This analysis demonstrates that each of the wind facilities show net benefits when using medium natural gas and medium CO_2 price-policy assumptions. And when the most conservative low natural gas and zero CO_2 price-policy assumptions are used, all repowered wind facilities show net benefits except for Leaning Juniper, where benefits equal costs. (Link Supplemental Direct, lines 252–263.)

Importantly, and as is the case with Mr. Higgins's alternative calculations, even if one were to accept that Mr. Hayet's methodology is valid for the 20-year IRP analysis—and to be clear, Mr. Hayet's approach is not valid or necessary—the conclusions drawn from this analysis are consistent with PacifiCorp's 20-year IRP analysis. Just like the economic analysis summarized in my supplemental direct testimony (Link Supplemental Direct, Table 2-SD), Mr. Hayet's own analysis shows that even in the lowest gross-benefit scenario that applies low natural gas and zero CO_2 price assumptions, the wind repowering project is expected to generate approximately

$110 million in present-value net benefits for customers. (Hayet Response, Table 5.)

Q. Based on his alternative methodology to use nominal costs for capital revenue requirement and PTCs in the 20-year analysis, Mr. Hayet concludes that six wind facilities should be excluded from the scope of the wind repowering project. (Hayet Response, lines 598–605.) Do you agree with Mr. Hayet's conclusion?

A. No. As discussed above, Mr. Hayet's alternative methodology is flawed and should not be used as the basis to determine whether specific wind facilities should be excluded from the scope of the wind repowering project. Based on this flawed analysis, Mr. Hayet appears to have arbitrarily drawn a line that suggests wind facilities expected to generate present-value net benefits at or below $5 million in the lowest gross-benefit scenario (assuming low natural gas and zero CO_2 price assumptions) should be eliminated from the project scope. The primary basis for Mr. Hayet's recommendation appears to be rooted in his assertion that certain wind facilities provide net benefits that are lower than others. But in making this recommendation, Mr. Hayet completely ignores the fact that his own analysis shows that the specific wind facilities he proposes be excluded are expected to generate net benefits even in the lowest gross-benefit scenario analyzed.

Q. Mr. Hayet presents an analysis that assumes a five-percent increase in total capital cost and a five-percent decrease in energy production.(Hayet Rebuttal, lines 650–714.) How do you respond?

A. First, Mr. Hayet's sensitivity analysis is applied to his alternative base case analysis, which for the reasons outlined above, is flawed. This alone renders any conclusions drawn from his sensitivity analysis irrelevant. Second, Mr. Hayet provides no basis to support the assumptions used in his sensitivity analysis. He does not provide any assessment of the company's wind repowering cost assumptions or the company's expected energy output projections. In short, Mr. Hayet does not explain why he believes PacifiCorp's cost-and-performance assumptions are not valid. Mr. Hayet again appears to have arbitrarily selected assumptions, applied those assumptions to a flawed analysis with an unwarranted focus on worst-case outcome, and used the results to support faulty conclusions.

As described by Mr. Hemstreet, nearly all of the wind repowering costs included in PacifiCorp's economic analysis are now firm and therefore the risk of a five percent cost increase is unlikely.

Q. Mr. Peaco critiques how energy-not-served ("ENS"), which is an output reported from the Planning and Risk model ("PaR"), influences PacifiCorp's economic analysis in the low natural gas, zero CO_2 price-policy scenario. (Peaco Response, lines 327–373.) Have you reviewed Mr. Peaco's critiques?

A. Yes. Mr. Peaco raises two concerns. First, Mr. Peaco asserts that the benefit attributed to the lower amount of ENS in a portfolio that contains all wind repowering projects relative to a portfolio that removes one of the wind repowering projects is a modeling artifact and does not represent an economic benefit that will actually accrue to ratepayers. (Peaco Response, lines 352–355.) Second, Mr. Peaco believes that the percentage of total benefits that are attributable to ENS benefits in the low natural gas, zero CO_2 price-policy scenario are inconsistent. (Peaco Rebuttal, lines 356–361.)

Q. What do the ENS outputs from PaR represent?

A. As described in my direct testimony, PaR is configured to analyze volatility and uncertainty in key system variables by using Monte Carlo sampling of load, wholesale electricity and natural gas prices, hydro generation, and thermal-unit outages. Consequently, PaR considers a distribution of system variable costs, including costs associated with energy or reserve deficiencies. (Link Direct, lines 207–218.) When PaR is configured to analyze these stochastic risks, there are certain combinations of variables that lead to low-probability outcomes where there are insufficient resources to meet load (*i.e.*, this is more likely to occur under high load, low hydro, and high thermal outage conditions).

PaR assigns a $1,000/megawatt-hour ("MWh") cost to ENS events, which serves two purposes. First, the ENS charge serves as a representative cost—tied to the historical cap established by the Federal Energy Regulatory Commission on supply offered into day-ahead and real-time markets—associated with having to make market purchases that could potentially be used avoid ENS events. Second, the ENS charge is sufficiently high to ensure that PaR does not "choose" ENS in its least-cost dispatch of system resources. For instance, if the ENS charge were set at $1/MWh, PaR would choose to reduce dispatch from system resources and market purchases to levels that would be insufficient to meet load because it would be lower cost.

Q. Are the ENS benefits that are included in PacifiCorp's economic analysis a benefit for customers?

A. Yes. PacifiCorp's project-by-project analysis compares system costs between two sets of resource portfolios—one portfolio with the full scope of repowered wind facilities and one portfolio where one of the wind facilities is assumed not to be repowered. The difference in system costs between these two cases represents the marginal system value of the wind facility that was removed. When a wind facility is removed from scope, there is less zero-fuel-cost energy output available to the system. This makes the system less reliable, and consequently, the ENS cost increases. Contrary to Mr. Peaco's claims, avoidance of this incremental ENS cost when repowering any given wind facility is a real and quantifiable customer benefit that is appropriately accounted for in PacifiCorp's economic analysis.

Mr. Peaco's concerns are based entirely on his review of ENS benefits in the low natural gas, zero CO_2 price-policy scenario. In this price-policy scenario, the net-power cost benefits from wind repowering are proportionately smaller than the net-power cost benefits in other price-policy scenarios that use a higher market-price forecast. Consequently, when calculated on a percentage basis, the relative contribution of other benefits from wind repowering, such as ENS benefits, will be greater in the low natural gas, zero CO_2 price-policy scenario than in other price-policy scenarios that use a higher market-price forecast.

If one were to assess the proportionate contribution of ENS benefits to the net benefits under the medium natural gas, medium CO_2 price-policy scenario, one would expect the ENS benefits, expressed as a percentage of total benefits, would be smaller than in the low natural gas, zero CO_2 price-policy scenario. Table 1-SR shows the contribution of ENS benefits as a percentage of net benefits for each wind facility under the medium natural gas, medium CO_2 price-policy scenario. In this price-policy scenario, the average contribution of ENS benefits to the net benefits of each wind facility is about one percent. As expected, this is considerably smaller than the contribution of ENS benefits to the net benefits under the low natural gas, zero CO_2

price-policy scenario as calculated by Mr. Peaco.

Table 1-SR
Project-by-Project ENS Benefits in the Medium Natural Gas, Medium CO_2 Price-Policy Scenario (PaR Nominal Revenue Requirement Analysis)

Wind Facility	ENS Benefit ($ million)	Total Net Benefit ($ million)	ENS as % of Net Benefits
Glenrock 1	($1)	($33)	2%
Glenrock 3	($0)	($11)	0%
Seven Mile Hill 1	($1)	($41)	2%
Seven Mile Hill 2	($0)	($10)	0%
High Plains	($1)	($22)	5%
McFadden Ridge	($0)	($7)	0%
Dunlap Ranch	($1)	($39)	1%
Rolling Hills	($1)	($15)	4%
Leaning Juniper	($0)	($8)	0%
Marengo 1	$0	($50)	0%
Marengo 2	$0	($20)	0%
Goodnoe Hills	$0	($26)	0%

Q. Is it reasonable for the contribution of ENS benefits in the low natural gas, zero CO_2 price scenario to vary among specific wind facilities?

A. Yes. The range in benefits among wind facilities account for the unique characteristics of each project (*i.e.*, incremental energy output, hourly generation profiles, *etc.*), and these unique characteristics contribute to a unique package of benefits. For instance, Mr. Peaco claims that two wind facilities—Seven Mile Hill 1 and High Plains—should have similar ENS benefits because they are nearly identical in project size and are geographically close to each other. (Peaco Response, lines 356–360.) However, Mr. Peaco fails to acknowledge that the expected repowered energy output from Seven Mile Hill 1 is approximately nine percent higher than the repowered energy output expected from High Plains. Moreover, Seven Mile Hill 1 is expected to be repowered four months earlier than High Plains. Considering the unique characteristics of each wind facility, variation in the contribution of ENS benefits to total net benefits among the wind facilities is expected and is not an indication that PacifiCorp's economic analysis is flawed.

Q. Mr. Hayet notes that PacifiCorp acknowledged there was an error in Table 3-SD of my supplemental direct testimony that affects the Marengo 1 project. (Hayet Response, lines 490–492.) Do you agree?

A. Yes. The net-present value benefits for Marengo 1 listed in Table 3-SD of my supplemental direct testimony were overstated by approximately $25 million. I agree that Mr. Hayet has made the appropriate corrections in Table 4 of his response testimony, which shows the Marengo 1 wind facility is expected to generate $50 million in net benefits under the medium natural gas, medium CO_2 price-policy scenario and $22 million in net benefits under the low gas, zero CO_2 price-policy scenario. The corrected result is also shown in Table-1SR above.

Q. Mr. Peaco claims that PacifiCorp has not explained differences in project-by-project results. (Peaco Response, lines 362–364.) Do you agree?

A. No. In support of his claim, Mr. Peaco references PacifiCorp's response to DPU data request 31.2(b), which refers to the company's response to DPU data request 29.5(b). Neither of these data requests ask PacifiCorp to explain differences in project-by-project results. These data requests question differences in the *total* project-by-project results relative to the aggregate results for the wind repowering project. PacifiCorp provided a responsive reply to each of these data requests.

Q. Did Mr. Peaco present alternative project-by-project results in his response testimony?

A. Yes. Mr. Peaco presents three alternative sets of project-by-project results using benefit-cost ratios for individual wind facilities that are based on his own estimates of energy benefits for the low natural gas, zero CO_2 and medium natural gas, medium CO_2 price-policy scenarios. (Peaco Response, lines 374–402.) These alternative results are derived from costs and benefits that extend through 2050. Mr. Peaco draws three conclusions from his analysis: 1) there is a wide range of benefit-cost ratios and some wind facilities have higher margins than others; 2) the method used to determine benefits impacts the relative benefit-cost ratios among wind facilities, as well as the rank order of projects; and 3) even under a lower-energy-benefits scenario, several of the projects exhibit positive benefit-cost ratios with some margin. (Peaco Response, lines 404–410.)

Q. Do you agree with Mr. Peaco's analysis and conclusions?

A. No. By replacing PacifiCorp's model results *and* extrapolated results beyond 2036 with an alternative estimate of energy benefits, Mr. Peaco completely disregards the company's robust system modeling. This system modeling, which relies on the same models used to establish a least-cost, least-risk resource portfolio in PacifiCorp's IRP process, accounts for the specific characteristics of each repowered wind facility and how each interacts with other system resources over time. For instance, the incremental energy that will be generated by the repowered wind facilities is not the same across all seasons, months, days, and hours. Importantly, the market value of energy is not the same across all seasons, months, days, and hours.

Incremental energy benefits from repowered wind facilities will be affected by the volume of incremental energy and the market price of energy in any given time interval. Mr. Peaco's simplified cost-benefit analysis does not capture this dynamic.

Incremental energy benefits from repowered wind facilities will further be influenced by a complex web of system variables, including the availability and dispatch cost of both existing and future generating resources, load, and transmission, which can limit access liquid markets. Mr. Peaco's analysis does not capture these interactions either. Consequently, Mr. Peaco's analysis should be viewed as a high-level and simplified representation of PacifiCorp's more detailed and accurate analysis. When viewed in this light, Mr. Peaco's high-level analysis can be used as a means to validate whether PacifiCorp's more accurate analysis is reasonable.

Q. Does Mr. Peaco's cost-benefit analysis validate that PacifiCorp's economic analysis is reasonable?

A. Yes. Table 2-SR summarizes the simple average, low, and high cost-benefit ratios among the 12 wind facilities, as calculated by Mr. Peaco and summarized in his response testimony. (Peaco Response, Table 5.) A cost-benefit ratio greater than one indicates that benefits exceed costs, and a cost-benefit ratio less than one indicates that costs exceed benefits.

In the medium natural gas, medium CO_2 price-policy scenario, Mr. Peaco's high-level analysis shows higher cost-benefit ratios than those he calculated from PacifiCorp's more accurate economic analysis. In the low natural gas, zero CO_2 price-policy scenario, Mr. Peaco's high-level estimate produces a cost-benefit ratio that is, on average, slightly higher than those he calculated from PacifiCorp's more accurate economic analysis. Moreover, the range in cost-benefit ratios from Mr. Peaco's high-level analysis is similar to the range in cost-benefit ratios that he calculated from PacifiCorp's more accurate analysis.

Table 2-SR
Comparison of Mr. Peaco's Cost-Benefit Analysis

	Medium Natural Gas, Medium CO_2		**Low Natural Gas, Zero CO_2**	
	Mr. Peaco's Cost-Benefit Ratio from PacifiCorp's Economic Analysis	**Mr. Peaco's Cost-Benefit Ratio from his High-Level Estimate**	**Mr. Peaco's Cost-Benefit Ratio from PacifiCorp's Economic Analysis**	**Mr. Peaco's Cost-Benefit Ratio from his High-Level Estimate**
Simple Average	1.29	1.42	1.17	1.19
Low	1.07	1.11	1.00	0.92
High	1.47	1.62	1.37	1.36

Q. What conclusions do you draw from Mr. Peaco's cost-benefit analysis?

A. Mr. Peaco's cost-benefit analysis validates that PacifiCorp's economic analysis is reasonable. Consistent with my findings from the company's economic analysis, Mr. Peaco's independent and high-level cost-benefit analysis shows that all of the repowered wind facilities are expected to generate net customer benefits when applying medium natural gas, medium CO_2 price-policy assumptions. Even in the most extreme low natural gas, zero CO_2 price-policy scenario, 11 of 12 wind facilities are expected to generate net customer benefits.

Moreover, the single project that does not show customer net benefits in the low natural gas, zero CO_2 price-policy scenario, shows a net benefit when the results from the medium natural gas, medium CO_2 price-policy scenario and low natural gas, zero CO_2 price-policy scenario are averaged together. In a previous voluntary resource decision request filed by the Company, DPU used this approach to evaluate the economics of the resource decision because, according to DPU's expert witness in that case, using the simple average of the price-policy scenario results produced a reasonable "risk-weighted benefit" that assumes each of the price-policy results is "equally likely." *In the Matter of the Voluntary Resource Request of Rocky Mountain*

Power for Approval of a Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4, Docket No. 12-035-92, DPU Exhibit 2.0 SR, lines 52–58 (Feb. 28, 2013). DPU's expert explained that using a simple average to produce a risk-weighted benefit was a "pretty good way" to do it because it was "neutral" and "doesn't attempt to say that lower gas prices are more likely or less likely in the future, just that they are equally likely with the base and high gas price forecasts." *In the Matter of the Voluntary Resource Request of Rocky Mountain Power for Approval of a Resource Decision to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 and 4*, Docket No. 12-035-92, Transcript, page 165, lines 1–10 (Mar. 7, 2013).

Q. Why did you not assess Mr. Peaco's high-level estimate of his cost-benefit ratios derived assuming energy benefits at 70 percent of Palo Verde market prices?

A. As discussed above, Mr. Peaco's cost-benefit analysis does not reflect the contemporaneous changes in energy output with changes in market prices, nor does it capture how these repowered wind facilities will interact with other system resources over time. For this reason, Mr. Peaco's cost-benefit analysis is best viewed as a simplified representation of PacifiCorp's more detailed and accurate analysis. In this capacity, Mr. Peaco's cost-benefit analysis derived by assuming a 30 percent reduction from Palo Verde market prices is not directly comparable to the company's results for these same price-policy scenarios. In fact, Mr. Peaco's cost-benefit analysis that assuming a 30 percent reduction in Palo Verde market prices from prices in the low natural gas, zero CO_2 price-policy scenario is effectively a high-level estimate of cost-benefit ratios assuming a significant and sustained reduction from the most extreme and lowest gross-benefit scenario analyzed by the company.

Q. Does Mr. Peaco provide any support explaining why he chose to reduce Palo Verde prices by 30 percent?

A. Not really. Mr. Peaco states that he applied this discount consistent with analysis presented in my testimony. (Peaco Response, 393–395.) This is not accurate. In my rebuttal and supplemental direct testimony, recognizing that long-term benefits are more difficult to forecast, I did present an analysis that replaced extrapolated system-benefit results beyond 2036 with Palo Verde market prices. And in developing this analysis, I did assume a case where Palo Verde prices were reduced by 30 percent. However, I did not apply this assumption to assess its impact on energy benefits before 2036, as was done by Mr. Peaco. It is one thing to assume that prices might drop by 30 percent from base case projections of the long term. It is entirely different to assume that market prices will drop by 30 percent from a low-price scenario over the near-term. It is highly unlikely that market prices will fall by nearly a third from a *low* price forecast over the near term.

ANNUAL REVENUE REQUIREMENT MODELING THROUGH 2050

Q. Dr. Zenger asserts that a project in excess of one billion dollars represents a large investment for a project "that is not needed" and that customer benefits are "small relative to the investment's size." (Zenger Rebuttal, lines 158–161.) Do you agree?

A. No. Dr. Zenger's assertion is not supported by facts. The wind repowering project is a key element of PacifiCorp's least-cost, least-risk plan to deliver reasonably priced and reliable service for customers. All of PacifiCorp's economic analysis presented in this proceeding relies on the same modeling tools used to produce the company's IRP. Each of the model runs for all price-policy scenarios used to calculate customer benefits-runs with and without the repowered wind facilities-achieve the same target planning reserve margin (13 percent) used in PacifiCorp's IRP in each year of the 20-year planning period. None of the model runs that include the repowered wind facilities achieves a planning reserve margin above 13 percent in any year of the 20-year forecast period. Contrary to Dr. Zenger's claims, the repowered wind facilities are needed, and resource portfolios that include the repowered wind facilities are lower cost and lower risk than resource portfolios that do not include the repowered wind facilities.

Dr. Zenger's claim that customer benefits are small relative to the size of the investment is also not supported by facts. The company's economic analysis shows *net* customer benefits based on the economic analysis over the remaining life ranging between $121 million and $466 million. The *gross* benefits are anything but small. The present-value *gross* benefits for the repowered wind facilities exceed project costs and conservatively range between $1.14 billion and $1.48 billion.

Q. Mr. Hayet argues that PacifiCorp's extrapolation of energy benefits during the 2037 to 2050 time frame overstates those benefits relative to what would have been derived using an expansion planning and production cost modeling approach. (Hayet Rebuttal, lines 386–428.) Do you agree?

A. No. It is perfectly reasonable to extrapolate system benefits during the 2037 to 2050 timeframe. 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. I also recognize that the value of this incremental energy can be assessed in different ways, and presented a long-term benefit sensitivity analysis that replaced extrapolated benefits with Palo Verde market prices. (Link Rebuttal, lines 421–447.) I updated this long-term benefit sensitivity in my supplemental direct testimony. (Link Supplemental Direct, lines 436–462.)

Mr. Hayet's criticism is based on calculating system benefits derived from approximately 739 gigawatt-hours ("GWh") of incremental annual energy before 2037 and then applying these benefits to approximately 3,478 GWh of incremental energy per year over the 2037 to 2050 time frame. Mr. Hayet argues that the replacement cost for a smaller amount of energy will generally lead to a higher per-unit value than it would for a larger amount of energy. All else equal, I agree with Mr. Hayet's observation. However, all else is not equal.

Beyond 2036, when the wind facilities would have otherwise hit the end of their lives, PacifiCorp will need to replace approximately 1,000 megawatts ("MW") of wind resource capacity with other resources if the wind facilities are not repowered. Consequently, in roughly the 2037 time frame, the repowered wind facilities will avoid the need to acquire new resources, which in turn, will further reduce system costs. Because the company is using modeled results over the 2028–2036 time frame, before resource deferral benefits are accounted for, to extrapolate system benefits in 2037 and beyond, PacifiCorp's extrapolated benefits are not overstated. If anything, the company's extrapolated benefits over the 2037–2050 timeframe are likely conservative because they do not capture customer savings associated with deferring resource-replacement costs.

Q. Mr. Hayet also expresses a concern that benefits over the 2037–2050 time frame are overstated because the extrapolation does not reflect a long-term, optimal resource-expansion plan. (Hayet Response, lines 467–480.) Do you agree with his conclusion?

A. No. Mr. Hayet incorrectly states that the company assumes no other resources will be added to the system over this period. (Hayet Response, lines 468–470.) I agree with Mr. Hayet that such an assumption would be unrealistic. Clearly, it is likely that PacifiCorp will need new resources beyond the 2036 IRP planning period. PacifiCorp's extrapolation methodology used in the annual revenue requirement analysis simply assumes that system impacts over the 2028–2036 time frame, inclusive of impacts to the resource portfolio, are a reasonable, and as discussed above, conservative proxy for system benefits that can be expected over the 2037–2050 time frame.

I also agree with Mr. Hayet that absent wind repowering (referred to as the "status quo" case by Mr. Hayet), PacifiCorp would have to replace approximately 1,000 MW of wind resource capacity that would otherwise have reached the end of its life. (Hayet Response, lines 473–477.) I do not agree with Mr. Hayet that this overstates the wind repowering net benefits. (Hayet Response, lines 477–480.) To the contrary, and as noted above, benefits from the wind repowering project would only improve from the values reported in the company's economic analysis if they accounted for avoided resource-deferral costs over the 2037–2050 time frame.

Q. Does Mr. Hayet discuss the long-term benefit sensitivity summarized in your supplemental direct testimony?

A. Yes. As noted above, my supplemental direct testimony summarizes an updated long-term benefit sensitivity where the extrapolated benefits are replaced with flat Palo Verde market prices under three scenarios—130 percent of Palo Verde, 100 percent of Palo Verde, and 70 percent of Palo Verde. Mr. Hayet dismisses the 130 percent and 100 percent scenarios because they result in levelized per-unit benefits that are higher than the company's the extrapolated values. (Hayet Response, lines 452–459.) Mr. Hayet's assessment of the 70 percent Palo Verde scenario is that it "resulted in a wind repowering net benefit of $213 million, which was much lower than the $351 million net benefit that Mr. Link discussed, it was also lower than the net benefit from his original extrapolation methodology, which was $273." (Hayet Response, lines 459–462.) Based on this observation, Mr. Hayet concludes that "these highlight the fact, that without performing proper modeling analyses, it would be speculative to even consider the 70% of PV case result reasonable." (Hayet Response, lines 462–464.)

Q. Is Mr. Hayet's conclusion reasonable?

A. No. I agree with Mr. Hayet's assessment that the $213 million net benefit from the 70 percent Palo Verde sensitivity is lower than the $351 million net benefit from the 100 percent Palo Verde sensitivity and that it is also lower than the $273 million net benefit when using extrapolated benefits. However, I do not understand how these basic facts lead Mr. Hayet to conclude that it is speculative to consider the 70 percent case result reasonable. If anything, the basic facts support the exact opposite conclusion.

When energy benefits are assumed to be reduced by 30 percent, one would expect that net benefits from the wind repowering project will be lower. This is precisely what the sensitivity results show—net benefits from the 100 percent Palo Verde sensitivity drop from $351 million to $213 million when net benefit assumptions are reduced in the 70 percent Palo Verde sensitivity. Similarly, when assumed energy benefits under the 70 percent Palo Verde sensitivity are lower than those assumed in the extrapolated results, one would expect the net benefits from the wind repower project to be directionally lower. Again, this is precisely what the sensitivity analysis shows—net benefits from the extrapolated results drop from $273 million to $213 million when net benefits are reduced in the 70 percent Palo Verde sensitivity. These results do not support Mr. Hayet's conclusion. Rather, they show that if one believes the extrapolated results are overstated, which they are not, then an even more conservative estimate of long-term benefits shows that the wind repowering project is *still* expected to generate significant net benefits for customers.

Q. Mr. Peaco questions PacifiCorp's use of Palo Verde prices in its long-term benefits sensitivity study and concludes that the implied market heat rate is unreasonable. (Peaco Response, lines 230–273.) How do you respond?

A. As described in my supplemental direct testimony, medium natural gas price assumptions are derived from PacifiCorp's OFPC. When producing the OFPC for natural gas and wholesale electricity prices, the first six years (through January 2024) reflect observed forward market prices as of December 29, 2017, which were validated against third-party broker quotes. In year seven (from February 2024 through January 2025), natural gas and wholesale electricity prices are a blend of the prior-year forward price and the fundamentals-based price in the subsequent year. Beyond year seven (beginning February 2025), natural gas and wholesale electricity prices in the OFPC reflect a fundamentals-based forecast. (Link Supplemental Direct, lines 79–107.) Mr. Peaco calculates an implied heat rate of 11,455 million British thermal units "(MMBtu")/MWh for 2022, and states that it is highly unlikely that a natural-gas-fired unit at this heat rate would be the marginal unit in the market. (Peaco Response, lines 264–271.)

Considering that PacifiCorp's OFPC reflects observed market forwards for natural gas and wholesale electricity prices through January 2024, Mr. Peaco's criticism of the implied market heat rate is not so much a criticism of a company assumption, but a criticism of the market itself. Contrary to Mr. Peaco's assertion, PacifiCorp's Palo Verde prices are not too high and inconsistent with natural gas price forecasts. (Peaco Response, lines 268–271.) PacifiCorp's OFPC for natural gas and wholesale electricity prices in 2022, and consequently the implied market heat rate in 2022, is not only consistent with natural gas price forecasts, it is based entirely on market information. As prices in the OFPC transition to a fundamentals-based forecast, the implied market heat rate begins to drop. By 2037, when I started using Palo Verde prices in the long-term benefits sensitivity study, I calculate the implied market heat rate under the medium natural gas scenario to be 9,260 MMBtu/MWh (ranging between 7,653 MMBtu/MWh in March 2037 and 10,831 MMBtu/MWh in August 2037). Consequently, the implied market heat rate calculated off of Palo Verde prices in the time frame that these prices were used in the long-term benefits sensitivity is more closely aligned with Mr. Peaco's expectations.

Q. Did Mr. Peaco recommend that PacifiCorp's economic analysis should be adjusted based on his review of market implied heat rates?

A. No.

CONCLUSION

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

A. The updated economic analysis summarized in my supplemental direct testimony continues to support 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 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 rebuttal testimony?

A. Yes.

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 Rebuttal Testimony of Joelle R. Steward

April 2018

Q. Are you the same Joelle R. Steward who previously submitted testimony in this proceeding on behalf of Rocky Mountain Power ("the Company"), a division of PacifiCorp?

A. Yes.

PURPOSE AND SUMMARY OF SUPPLEMENTAL REBUTTAL TESTIMONY

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

A. In support of the Company's application asking the Utah Public Service Commission ("Commission") to approve innovative or non-traditional ratemaking treatment for the wind repowering project, I respond to regulatory policy issues raised in the response testimonies of the Utah Division of Public Utilities ("DPU") witness Dr. Joni S. Zenger, DPU witness Mr. Charles E. Peterson, DPU witness David Thomson, Office of Consumer Services ("OCS") witness Cheryl Murray, OCS witness Donna Ramas, and Utah Association of Energy Users ("UAE") witness Mr. Kevin C. Higgins.

Q. Please summarize your testimony.

A. The repowering project provides substantial net benefits for customers and should be approved by the Commission. Over the course of this case, the benefits have been repeatedly tested by changing market conditions, changes to the federal income tax code, and yet, despite these changes, the benefits persist. Because repowering provides benefits to customers, the Company should be allowed the opportunity to recover all its prudently incurred costs. Therefore:

- The Commission should reject proposed cost recovery conditions because they would unreasonably punish the Company for pursing the least-cost, least-risk resource decision.

- The Commission should approve the proposed Resource Tracking Mechanism (“RTM”), which is a straightforward proposal designed to more accurately match the costs and benefits of repowering, while allowing the Company to minimize the need for complex and resource intensive rate cases.

The Company provided the Commission and parties with a thorough and comprehensive filing detailing the proposed repowering project. Over the course of this case, parties have conducted in-depth discovery to test the Company’s modeling and the reasonableness of the Company’s risk mitigation strategies for the repowering project. The Company reasonably updated its economic analysis February 2, 2018 to reflect changes in the tax code and the most up-to-date market and cost and performance information, as outlined in the November 22, 2017 Unopposed Motion to Amend Procedural Schedule. Compared to June 2017, when the Company made its initial filing, the benefits of repowering are more certain, risks have decreased, and the Company has demonstrated that repowering is most likely to provide the lowest reasonable cost utility service.

REPOWERING COST RECOVERY

Q. Mr. Higgins recommends several conditions that he believes the Commission should apply if it approves the repowering project. (Higgins Resp., lines 58-118.) Are Mr. Higgins’ proposed conditions reasonable?

A. No. I will address each of his proposed conditions below, but, conceptually, the premise underlying Mr. Higgins’ proposed conditions is that repowering is an “opportunity investment” that requires an entirely different analytic process for review and approval.

On the contrary, repowering is straightforward-the Company has the opportunity to upgrade its existing facilities and reduce costs to customers. The allocation of risk between the Company and customers should be no different for repowering than it would be without repowering.

Q. What is Mr. Higgins' first proposed condition?

A. Mr. Higgins recommends that the Commission condition cost recovery on the Company's "ability to demonstrate that construction costs have come in at or below its estimated costs in this case, and that, measured over a reasonable period of time, the megawatt-hours produced by the repowered facilities are equal to or greater than the forecasted production provided in this proceeding." (Higgins Resp., lines 61-66.) Mr. Higgins recommends that, notwithstanding a prudence determination in this case, if this condition is not met "the Commission expressly reserve the right in a future rate case to reduce the Company's recovery of costs." (Higgins Resp., lines 66-71.)

Q. How do you respond to this condition?

A. Mr. Higgins' cost and performance condition is entirely unprecedented and unnecessary in this case. Notably, Mr. Higgins points to no other circumstance where the Commission has conditioned a prudence determination on the future performance of a resource or applied a cost cap to a utility investment. Again, repowering is no different in this respect from any utility investment and does not warrant extraordinary and unprecedented conditions.

Moreover, as described in the testimony of Company witness Mr. Timothy J. Hemstreet, the Company has largely mitigated the risks within its control of construction cost over-runs and schedule delays that would adversely impact customers, and has also negotiated contracts that mitigate, to the extent feasible, the performance risk associated with the repowered facilities. Thus, the specific risks identified by Mr. Higgins have been reasonably addressed by the Company and do not require the extraordinary conditions Mr. Higgins recommends.

Q. What is Mr. Higgins second proposed condition?

A. As in his Direct Testimony, Mr. Higgins again recommends that if the Commission approves the wind repowering project, the approval should be made conditional on a reduction of 200 basis points to the authorized rate of return on the undepreciated balance of the retired plant. (Higgins Resp., line 72 to line 85.)

Q. Is this proposed condition reasonable?

A. No. If the Commission determines that the wind repowering project provides customer benefits, including the amortization of the existing plant, there is no justification to provide different recovery than any other prudent investment. As explained in the Company's October 2017 rebuttal testimony, this condition is contrary to Commission precedent. (*See* Larsen Reb., lines 129-145.)

The Company's economic analysis, including recovery of existing plant, demonstrates that repowering is the lowest cost alternative for supplying energy to customers. Reducing the return on the replaced equipment would penalize the Company for developing and implementing a resource strategy that reduces costs for customers.

Q. Mr. Higgins claims that his condition limiting the return on the retired plant is necessary to better balance, upfront, the potential benefits from this proposition for both customers and the Company. (Higgins Resp., lines 795-797.) How do you respond to this claim?

A. Mr. Higgins' premise is that the Company's recovery of its cost of service, including a regulated return on its capital costs, is a benefit subject to reallocation to customers. This premise is contrary to basic ratemaking. The cost of capital is no different than any other prudent cost recoverable in rates if incurred to provide utility service. Mr. Higgins' position that some of the Company's costs of the repowering project are an allocable benefit to customers is really a proposal to partially disallow cost recovery, notwithstanding a Commission determination the investment is prudent and beneficial to customers.

By focusing only on the Company's cost of capital and comparing it to the customer *net* benefits, Mr. Higgins' presents a distorted view of the benefits of the repowering project. The Company's analysis shows that present-value *gross* customer benefits over the remaining life of the repowered facilities range between $1.14 billion and $1.48 billion, which compares to the present-value costs of $1.02 billion. Because repowering provides *net* benefits, customers will receive more than they pay for and therefore there is no need to better balance the costs and benefits as Mr. Higgins claims.

Q. Mr. Philip Hayet also proposes two conditions. (Hayet Resp., lines 794-802.) Are his conditions reasonable?

A. No. First, Mr. Hayet recommends that the Company's future cost recovery should be limited to the capital expenditures and O&M costs used in the economic analysis in this case. Mr. Hayet does not provide any explicit basis for this recommendation. As described above, however, because the repowering project is comparable to any other utility investment included in the Company's least-cost, least-risk resource portfolio, there is no reason to apply such an unprecedented condition on approval of the resource decision.

Second, Mr. Hayet recommends that the Company guarantee the PTC and energy benefits at 95 percent of the amount included in the Company's economic analysis. Mr. Hayet claims that if the Company is confident in its projection, then this condition is reasonable. I disagree, however, that such an unprecedented condition is reasonable. To my knowledge, the Commission has never before imputed a performance guarantee of this type for a resource decision of this type, and there is no basis to do so here.

Q. Ms. Ramas requests that if approved, the Commission lock in Utah's allocated share of the repowering investment based on the Company's current interstate allocation methodology. (Ramas Resp., lines 303-337.) Is this a reasonable recommendation?

A. No. This is contrary to the 2017 Protocol currently approved for inter-jurisdictional cost allocation in the state of Utah, which uses dynamic allocation factors. Moreover, any change to inter-jurisdictional cost allocations in the future will be approved by the Commission and should not by restricted by this proceeding. In effect, Ms. Ramas is recommending that the Commission pre-determine the outcome of the current Multi-State Process, which would be detrimental to the continuing negotiations with stakeholders throughout the Company's service area.

In addition, if Utah's allocated costs associated with these projects are fixed, then the benefits, including production tax credits and reduced net power costs, must also be fixed. Any change of this type would require resource subscriptions which are not allowed under the 2017 Protocol.

Q. What is the Company's response to Mr. Peterson's suggestion that the retired assets be amortized over 10 years, instead of 30, to match the availability of PTC's? (Peterson Resp., lines 84-94.)

A. The Company's proposal to amortize the retired assets over the remaining life of the repowered facilities is consistent with typical ratemaking. The exact amortization period for those assets would be better addressed as part of the new depreciation study the Company will be filing later this year. As part of the depreciation study the DPU or other parties can propose a higher depreciation rate for the wind resources or other depreciation changes that they feel are appropriate.

Q. Mr. Peterson, in DPU Exhibit 4.1 RESP, determines that the present value difference between a 30-year amortization and a 10-year amortization of the Legacy equipment is approximately $200 million. Do you offer any additional observations on Mr. Peterson's exhibit?

A. Yes. While Mr. Peterson's calculations are technically correct, he is only calculating the present value on a portion of the revenue requirement associated with recovery of the legacy equipment-the amortization, or return of, the investment. Mr. Peterson has not included the return on investment in his comparison, which if he had would have mostly eliminated the net present value difference between the two amortization periods he is comparing. Additionally, Mr. Peterson shows that the Company's proposal to amortize the remaining plant over thirty years produces a net present value that is $200 million less than his proposal. Therefore, I believe Mr. Peterson's exhibit shows that the Company's proposal is reasonable because it results in a lower cost to customers.

RESOURCE TRACKING MECHANISM

Q. Mr. Higgins and Ms. Ramas recommend that the Commission reject the RTM and instead allow the Company to recover the costs of repowering through a general rate case filing. (Higgins Resp. lines 976-979 and Ramas Resp., lines 49-59.) How do you respond?

A. The Company still supports the proposed RTM because it will more accurately match the costs and benefits of the repowering project and prevent the need for multiple general rate cases. Moreover, contrary to Ms. Ramas' claim that the RTM shifts risk to customers, the Company has agreed to a cap so that the RTM will only act as a customer credit, thereby addressing concerns that it is an improper risk-shifting mechanism.

Q. Why does Mr. Higgins recommend that the Commission reject the RTM?

A. Although Mr. Higgins previously testified that the "RTM appears to be logically constructed and reasonably balances the interests of the Company and customers," (Higgins Direct, lines 440-442) he is concerned that the RTM undermines the Company's incentive to control costs because it is what he describes as a "single-issue tracker mechanism." (Higgins Resp., lines 1022-1028.)

Q. Mr. Higgins argues that ratemaking is not a "cost reimbursement" exercise and that regulatory lag is actually a good thing because it encourages efficient operations. (Higgins Resp., lines986-1028.) Do you agree?

A. For the most part, no. I agree that ratemaking is not "cost reimbursement," but I disagree that the RTM is a form of "cost reimbursement" as used by Mr. Higgins. It is well established that utilities are afforded a reasonable opportunity to recover their costs, and the RTM is designed to balance recovery of costs with benefits. The RTM is not an automatic pass through of costs. Rather, the RTM is a mechanism that tracks and matches costs and benefits on a timelier basis and allows parties and the Commission to determine that the costs were prudently incurred before being included in rates. Without the RTM, or a modification to exclude net power cost benefits from the Energy Balancing Account ("EBA"), customers would receive benefits without paying for the costs necessary to achieve those benefits. Moreover, the Company continues to bear the risk of prudent implementation of costs for the repowering project regardless of the recovery method chosen because imprudent implementation or management of resources would be subject to a disallowance. Accordingly, the Company continues to be motivated to manage the costs associated with repowering as well as all other costs.

In addition, the Company's proposed cap for the RTM provides a significant incentive to control costs.

Q. Mr. Higgins also recommends a three-part test that should be considered by the Commission before implementing a tracking mechanism like the RTM. (Higgins Resp., lines 1033-1044.) Do you agree with Mr. Higgins's proposed test?

A. No. Mr. Higgins recommends that the Commission consider whether the recoverable costs are (1) volatile, (2) beyond the Company's control, and (3) significant. Notably missing from his artificial test is any consideration of matching costs and benefits, which is one of the fundamental reasons that the Company has requested the RTM. His test also doesn't consider if the mechanism would create a process improvement to align cost drivers to minimize the frequency of general rate cases. Moreover, the three considerations outlined by Mr. Higgins may be reasonable for automatic pass-through mechanisms that receive no review. The RTM, however, is not an automatic pass-through mechanism because parties and the Commission will have an opportunity to audit all costs before they are included in rates through the RTM, similar to the Company's EBA. Even if the Commission were to consider Mr. Higgins's test, his considerations support approval of the RTM. First, the Company has recommended that the RTM remain in place after the repowering projects are in base rates to act as a PTC tracker mechanism. The PTCs generated by the repowered projects are potentially volatile and outside the Company's control-meeting the first and second component of Mr. Higgins's test. Third, the revenue requirement associated with the PTCs produced by the repowered facilities is significant enough to warrant automatic pass-through to customers.

Q. Mr. Higgins, Mr. Thomson, and Ms. Ramas question the validity of the Company's proposed cap on the RTM now that the Company has proposed to defer excess costs resulting from recent changes in the federal tax code. (Higgins Resp., lines 1098-1113; Thomson Resp., lines 28-52; and Ramas Resp., lines 139-150.) How do you respond to this testimony?

A. The Company proposed to cap repowering costs based on the economics of the repowering project when the federal corporate tax rate was 35 percent. In other words, the Company committed that the repowering RTM would not impose a surcharge on customers. The Company stands by that commitment. But the proposed cap on the RTM should not double-count the revenue requirement impact of tax reform, which is what would occur if the repowering cap does not take into account the impact of tax reform. If tax reform creates costs in excess of the RTM cap and those costs are not recoverable, then those unrecovered costs should not be refunded again when the overall impact of tax reform is accounted for in customer rates. To return only the tax savings associated with tax reform to customers while absorbing the tax increases was not intended by, and should not be the result of implementing the RTM. Furthermore, the Company is not seeking a Commission approval of the proposed deferred in this proceeding. The Company will make a filing when the costs are incurred.

Q. Ms. Murray claims that the RTM is problematic because it is difficult to know what amounts are included in base rates for purposes of determining the incremental costs and benefits of repowering that will be included in the RTM. (Murray Resp., lines 55-58.) How to you respond to this concern?

A. The incremental costs included in the RTM will be largely determined based on the known historical data that can be measured and verified by the parties before inclusion in customer rates. (S*ee, e.g.*, Larsen Rebuttal, lines 264-290.)

Q. Ms. Ramas states that the Company has not provided evidence that it would be unable to earn its allowed rate of return if the RTM is rejected. (Ramas Resp., lines 86-91.) Is an earnings test an appropriate measure to determine whether to establish a mechanism for cost recovery?

A. No. The fact that the Company's most recent historical earnings may have been sufficient to allow it to make the repowering investment without an RTM does not mean that the Company's future earnings will be sufficient. The RTM is designed to allow the Company to match the costs and benefits of the repowering project without needing to file multiple general rate cases.

Q. If the RTM is approved, does Mr. Higgins propose any modifications?

A. Yes. Mr. Higgins' proposes three modifications. (Higgins Resp., lines 106-118.)

First, Mr. Higgins recommends that the RTM should not be used as a PTC tracking mechanism once the full costs and benefits of repowering are included in base rates following the next general rate case. But tracking PTCs as an ongoing component of the RTM after all other components are included in rates ensures that customers receive the full benefits of the PTCs and therefore better matches the costs and benefits of repowering.

Second, Mr. Higgins would disallow the impact of tax reform to the extent it exceeded the proposed cap on the RTM. As explained above, such an approach improperly double-counts the benefits of tax reform.

Third, Mr. Higgins recommends that if the RTM includes incremental property tax expenses associated with the new plant, it also accounts for the reduction of property tax expenses related to the replaced equipment. This view is also held by Ms.

Murray. (Murray Resp., lines 61-62.) As described in the Company's October 2017 rebuttal testimony, even though a portion of the plant is being replaced, this will not directly reduce the Company's property tax expense. (*See* Larsen Rebuttal, lines 326-332.) The method the Company is proposing is a reasonable method for estimating the property tax impact using the average rate from the last general rate case.

SUFFICIENCY OF APPLICATION

Q. The DPU criticizes the Company's initial filing, claiming that the Company "filed very little in its Application" and therefore required parties to use discovery to analyze the Company's case. (Zenger Resp., lines 280-284.) Is this a fair representation of the Company's filing?

A. No. The Company's initial filing was 163 pages, including an Application and detailed supporting testimony from four witnesses. It is unclear what additional information Dr. Zenger believes should have been included but was not. Given the size and complexity of the repowering project, the Company could not reasonably be expected to anticipate all of the various questions that intervening parties may pursue discovery on prior to the application being filed. The Company has put forth its best efforts to be responsive to the various requests for information associated with a very large and complex project. Additionally, in order to expedite discovery for the Company's February 2, 2018 supplemental filing, the Company met with the Division, Office, and UAE in December 2017 and requested a list of what additional information or supplemental discovery responses the parties were like provided with the filing. The Company then provided the requested information with the February 2, 2018 supplemental filing.

The fact that the parties conducted thorough discovery does not indicate that the initial filing was lacking; rather, it indicates that this case has been thoroughly analyzed by the parties. The fact this case has been pending for nearly a year, allowing the parties to conduct thorough discovery and file multiple rounds of testimony, indicates that there is no basis to claim an insufficient opportunity to analyze the case.

Q. The DPU also claims that the Company filed its case "before much due diligence and preparatory work was completed." (Zenger Resp., lines 290-291.) Is this a fair statement?

A. No. The DPU's criticism rings hollow considering that Dr. Zenger's previous testimony faulted the Company for performing too much due diligence before filing this case. (*See* Zenger Direct, lines 88-108.) To be clear, the Company performed extensive due diligence prior to filing this case, and continued throughout the pendency of this case, as described in Mr. Hemstreet's testimony. The continued due diligence and project implementation has now made the benefits of repowering more certain and reduced customer risk. The Company has not, however, unequivocally committed itself to the repowering project and has prudently negotiated off-ramps in the event of changing circumstances or adverse regulatory outcomes.

Q. The DPU also claims that the Company's case "has evolved with material changes in the project or the Company's analysis three times now." (Zenger Resp., lines 112-113.) Do you agree with this characterization?

A. No. The Company reasonably updated its economic analysis in its October 2017 rebuttal testimony to account for updated loads, market prices, and cost and performance assumptions for the repowered facilities based on events occurring subsequent to the initial filing. The Company then updated its analysis again in February 2018 to account for updated market prices, cost and performance assumptions, and the impact of tax reform, consistent with the November 22, 2017 Unopposed Motion to Amend Procedural Schedule. The DPU's implication that the Company should not have updated its analysis based on changing market circumstances and tax policy is entirely unreasonable as the elements for the filing included in the motion were agreed upon by parties prior to filing the motion. If the Company had not provided the updates, we would have been criticized for using inaccurate and dated information. The Commission should review the economics of the repowering project based on the most accurate and up-to-date information.

The DPU's criticism is also undermined by the fact that some of the additional analysis provided by the Company in its responsive testimony was directly responsive to DPU's own requests. Mr. Daniel Peaco's direct testimony specifically requested that he "Company provide[] a new analysis" and address customer risks associated with repowering. (Peaco Direct, lines 72-75.) It is unfair and frustrating that Dr. Zenger now criticizes the Company for doing precisely what DPU requested.

Q. The DPU further criticizes the Company for proposing additional rounds of testimony to account for changes in the federal corporate income tax rate that were expected to occur in late 2017. (Zenger Resp., lines 113-122.) Is this a fair criticism?

A. No. First, all of the parties—including DPU—agreed to the additional testimony specifically because the parties—including DPU—stressed in their testimony that tax reform could have a substantial impact on the economics of the repowering project. (*See*, *e.g.*, Peaco Surrebuttal, lines 504-530.)

Second, the parties—including DPU—agreed to the specific additional analysis that they wanted the Company to provide in its supplemental filing. So Dr. Zenger cannot now criticize the Company for providing the analysis that DPU requested and that the Company agreed to perform.

Third, there is no basis for Dr. Zenger to claim that "certain updates and analysis" that were included in the supplemental testimony filed in February 2018 "should have been filed in the Company's initial Application." (Zenger Resp., lines 120-122.) The parties agreed that the Company's supplemental testimony would provide updated analysis that accounted for tax reform (which could not have been included in the June 2017 filing), official forward price curves effective as of January 1, 2018, or the most recent official price curve available (which could not have been included in the June 2017 filing), and updates for known changes in wind repowering costs and performance, and projected changes in CO_2 costs (which could not have been included in the June 2017 filing). Additionally, the Company agreed to the timeline that parties requested to review the supplemental analysis—two months—and delayed several project milestones in order to accommodate parties' review.

Q. Does this conclude your second supplemental rebuttal testimony?

A. Yes.