REDACTED
Docket No. 20000-520-EA-17
Witness: Rick T. Link

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Supplemental Direct Testimony of Rick T. Link

January 2018

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

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

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

A. In my testimony, I summarize the results of the 2017R Request for Proposals ("RFP"). I also provide updates to the economic analysis that demonstrate increasing customer benefits from the new wind resources ("Wind Projects") and construction of the Aeolus-to-Bridger/Anticline line and network upgrades ("Transmission Projects") (collectively, the "Combined Projects").

Q. Please summarize your supplemental direct testimony.

A. The 2017R RFP generated robust and competitive responses from market participants. The final shortlist includes four new wind projects located in Wyoming from three different bidders. The total capacity of the four projects is 1,170 megawatts ("MW") including three of the benchmark facilities (TB Flats I and II, now combined as a single project, and McFadden Ridge II), and two new facilities (Cedar Springs and Uinta). Uinta is a build-transfer agreement ("BTA") totaling 161 MW, Cedar Springs is one-half BTA and one-half power purchase agreement ("PPA"), for a total of 400 MW, and TB Flats I and II and McFadden Ridge II are Company-built facilities, totaling 500 MW and 109 MW, respectively.

The results of the 2017R RFP and the extensive modeling that supports it confirm that the Combined Projects are the least-cost, least-risk path available to serve the Company's customers by meeting both near-term and long-term needs for additional resources. My supplemental direct testimony explains the following:

- The Combined Projects provide net customer benefits under all scenarios studied through 2036, and in seven of the nine scenarios through 2050.
- Customer benefits increase to $177 million in the medium case through 2050 (as compared to $137 million in the original filing), and range from $311 million to $343 million in the medium case through 2036.
- The analysis reflects changes in federal tax law that were enacted in December 2017, and updated best-and-final pricing from bidders received December 21, 2017, after the federal tax law changes were known.
- The treatment of production tax credits ("PTCs") in the system modeling scenarios extending out through 2036 has been changed to better reflect how the PTCs will flow through to customers, which makes the treatment consistent with the nominal revenue requirement results that extend out through 2050.
- Sensitivity analysis shows substantial benefits of the Combined Projects persist when paired with PacifiCorp's wind repowering project and are not displaced when considering the potential procurement of solar PPA bids submitted into the on-going RFP for solar resources, the 2017S RFP.

2017R RFP RESULTS

Q. When did PacifiCorp issue the 2017R RFP?

A. PacifiCorp issued the 2017R RFP on September 27, 2017, after it was approved by the Public Service Commission of Utah ("Commission") on September 22, 2017, and the Public Utility Commission of Oregon ("Oregon Commission") on September 27, 2017.

Q. Was the scope of the 2017R RFP modified before it was issued to include non-Wyoming wind projects?

A. Yes. The Company's original proposal limited the RFP to wind resources capable of interconnecting to or delivering on a firm basis to the Company's transmission system in Wyoming. In response to issues raised in the RFP approval process, and consistent with the recommendations of Merrimack Energy Group, Inc., the Utah independent evaluator ("IE"), the Company expanded the 2017R RFP to allow bids from non-Wyoming wind projects capable of interconnecting to or delivering on a firm basis to anywhere on the Company's transmission system.

Q. In response to the Commission's approval order, did the Company decide to issue a solar RFP to run concurrently with the 2017R RFP?

A. Yes. In its order approving the 2017R RFP, the Commission suggested, but did not require, a modification to expand the 2017R RFP to solicit solar resource bids. To maintain the 2017R RFP schedule while addressing the Commission's suggestion, the Company issued a separate solicitation process for solar resources, the 2017S RFP, on November 15, 2017. The 2017S RFP sought bids for solar resources up to 300 MW per individual project that can deliver energy and capacity to the Company's transmission system.

Similar to the 2017R RFP, the Company retained London Economics International, LLC ("Solar RFP IE") as the IE to oversee the solar RFP process. The 2017S RFP schedule allowed the Company to: (1) evaluate how solar resource bids might impact the economic analysis of bids selected to the final shortlist in the 2017R RFP without delaying the schedule for the 2017R RFP; and (2) explore whether new solar resource opportunities might provide all-in economic benefits for customers.

Q. When did the Company receive initial bids in the 2017R RFP?

A. The Company received initial bids for Wyoming wind projects on October 17, 2017, and initial bids for non-Wyoming wind projects on October 24, 2017. The 2017R RFP was well received by the market, as indicated by the fact the Company received Wyoming wind proposals from nine bidders offering 49 bid alternatives for 13 wind projects. The Company also received non-Wyoming wind proposals from five bidders offering 15 bid alternatives for six wind projects. In aggregate, 5,219 MW of new wind resource capacity was bid into the 2017R RFP (4,624 MW of Wyoming wind and 595 MW of non-Wyoming wind).

Q. When did the Company complete its initial shortlist evaluation?

A. The Company completed its initial shortlist evaluation and scoring and began a capacity factor evaluation process, performed by Sapere Consulting, on November 12, 2017. The Utah IE and Bates White, LLC, the Oregon IE, completed their review of the initial shortlist on November 17, 2017. Once the IEs completed their review of the initial shortlist, the Company notified bidders whether their proposed projects were selected to the initial shortlist and provided an opportunity for bidders selected to the initial shortlist to update pricing. On November 22, 2017, the Company received best-and-final pricing for bids selected to the initial shortlist.

Q. Did the Company use the best-and-final pricing received on November 22, 2017, to establish the 2017R RFP final shortlist?

A. No. On November 16, 2017, shortly after best-and-final pricing was received, the U.S. House of Representatives passed H.R. 1, which included changes in federal tax law reasonably expected to affect bid pricing. On December 2, 2017, the U.S. Senate passed its own version of a tax-reform bill, setting the stage for a conference committee to reconcile differences between the two bills. On December 7, 2017, the Company notified bidders that it would request updated pricing to reflect potential changes in federal tax law once the reconciliation process initiated by Congress was completed. On December 15, 2017, the conference committee approved its report on H.R. 1, and on December 18, 2017, the Company notified bidders that updated best-and-final pricing reflecting federal tax provisions outlined in the conference committee's report on H.R. 1 must be submitted by December 21, 2017. The updated best-and-final pricing received on December 21, 2017, was used to establish the 2017R RFP final shortlist.

Q. Were the provisions in the conference committee's report on H.R. 1 ultimately passed by Congress and signed by the President?

A. Yes. Congress passed H.R. 1 on December 20, 2017. The bill became law on December 22, 2017 when it was signed by President Trump.

Q. How did the Company select which bids to include in the 2017R RFP final shortlist?

A. Consistent with the bid evaluation and selection process outlined in the Commission-approved RFP, the final shortlist selection process was implemented in two basic phases--the portfolio-development phase and the scenario-risk phase.

Q. Please describe the portfolio-development phase.

A. The portfolio-development phase identifies the least-cost combination of bids using a methodology that is consistent with the approach used to produce resource portfolios in the integrated resource plan (“IRP”). The portfolio-development phase was initiated by processing best-and-final pricing for each bid into the cost-and-performance data required as inputs to the System Optimizer ("SO") model and the Planning and Risk model ("PaR").

The SO model was then used to develop bid portfolios containing the least-cost combination of bids over a twenty-year planning horizon (2017 through 2036). When choosing the least-cost combination of bids, the SO model was configured to select from all of the bids and bid alternatives included in the initial shortlist and all other proxy-resource alternatives used to develop resource portfolios in the PacifiCorp's 2017 IRP (*i.e.*, front-office transactions or "FOTs", demand-side management resources, new thermal resources, *etc.*). The Company did not force the SO model to select any bid or any combination of bids.

The Company developed bid portfolios for nine price-policy scenarios, which, as described in my direct testimony, are developed by pairing three natural-gas price forecasts (low, medium, and high) with three carbon dioxide ("CO_2") price forecasts (zero, medium, and high). I describe updates made to these price-policy scenarios since the Company's original filing later in my testimony.

For each price-policy scenario, the Company also calculated the present-value revenue-requirement differential ("PVRR(d)") between two system simulations–one that includes 2017R RFP bids and the Transmission Projects and one without. These studies were prepared using the SO model and PaR and are used to quantify the economic impact of top-performing bid portfolios.

The combination of bids selected by the SO model across each of the nine price-policy scenarios and the accompanying PVRR(d) results, calculated using the SO model and PaR, identifies the bid portfolios expected to deliver economic benefits for customers. Specific to the 2017R RFP, this process identified two bid portfolios that were then further evaluated in the scenario-risk analysis phase of the bid-selection process.

Q. When developing bid portfolios, how much new wind capacity could the SO model select in eastern Wyoming?

A. Consistent with the assumptions in my direct testimony, the Company assumed that the Aeolus-to-Bridger/Anticline transmission line will enable interconnection of up to 1,270 MW of additional wind resources to PacifiCorp's transmission system in eastern Wyoming. Considering that there is a transmission customer in the interconnection queue with an executed interconnection agreement for a 240 MW qualifying facility ("QF") in the area, the Company assumed that sufficient interconnection capacity must be reserved for this transmission customer. Consequently, the Company restricted new wind resource bids in eastern Wyoming to 1,030 MW (1,270 MW less 240 MW).

Q. Please describe the scenario-risk-analysis phase of the final shortlist bid-evaluation process.

A. The scenario-risk phase of the bid-evaluation process ensures that the two top-performing bid portfolios identified in the portfolio-development phase of the selection process are analyzed among all nine price-policy scenarios. For instance, one of the bid portfolios identified in the portfolio-development phase includes a consistent set of bids selected by the SO model in five of the nine price-policy scenarios. The second bid portfolio, which includes the same bids that are in the first bid portfolio plus an additional bid, was selected by the SO model in the other four price-policy scenarios.

In the scenario-risk phase of the bid-selection process, the first bid portfolio was analyzed in the four price-policy scenarios where it was not selected as the least-cost bid portfolio. Similarly, the second bid portfolio was analyzed in the five price-policy scenarios where it was not selected as the least-cost bid portfolio.

As in the portfolio-development phase, these studies were performed using the SO model and PaR. The outputs from these studies were used to calculate the PVRR(d) between two system simulations—one that includes 2017R RFP bids and the Transmission Projects and one without. The Company then used the PVRR(d) results to initially identify the least-cost, least-risk bid portfolio.

Q. Did the Company identify any issues in the modeling initially used in the portfolio-development phase and scenario-risk phase of the bid-selection process?

A. Yes. On-going due-diligence review of the least-cost, least-risk bid portfolio allowed the Company to identify two issues with specific bids that affected the initial economic analysis. First, the Company discovered that capacity factor adjustments applied to two bids were only partially captured in the SO model and PaR simulations. Consistent with recommendations from Sapere Consulting, the net capacity factor for two projects were assessed at 92 percent of the net capacity factor proposed by [redacted]. When applying the net-capacity-factor adjustment in the SO model and PaR, its impact on federal PTC benefits and bid costs were accurately captured. However, its impact on the expected energy output was not captured. This had the effect of overstating net power cost ("NPC") benefits associated with these bids, one of which was included in the initial least-cost, least-risk bid portfolio.

The second issue was identified when reviewing redline edits made by [redacted] to the 2017R RFP pro-forma BTA. Specifically, the Company noticed that [redacted], which submitted several BTA bids, with two of these bids initially included in the least-cost, least-risk bid portfolio, struck language specifying that it would be responsible for applicable sales taxes. [redacted] subsequently confirmed that its price proposals did not include sales tax, and the Company confirmed that it did not include sales tax in its evaluation of costs for any of the [redacted] BTA bids.

Q. How did the Company evaluate the impact of these two issues in the bid-selection process?

A. The Company first corrected the net-capacity-factor inputs for the two projects proposed by [redacted] and included the estimated cost of sales tax on all of the [redacted] BTA bids. Once these corrections were made, the Company reran the SO model portfolio-development studies for two price-policy scenarios–one pairing low natural gas prices with zero CO_2 prices and one pairing medium natural gas prices with medium CO_2 prices.

Q. Did the correction to the net-capacity-factor inputs for the [redacted] bids cause a change in the bid portfolio in these updated SO model studies?

A. No. The [redacted] bid that was included in the original least-cost, least-risk bid portfolio continued to be selected by the SO model in both price-policy scenarios.

Q. Did the application of sales tax to the [redacted] BTA bids cause a change in the bid portfolio in these updated SO model studies?

A. Yes. When sales tax was added to the cost of the [redacted] BTA bids, one of its two projects that was originally included in the initial least-cost, least-risk bid portfolio was replaced with another bid. Specifically, [redacted] BTA bid for the [redacted] was replaced with [redacted] for the [redacted].

Q. Did the Company update its economic analysis to account for this update to the bid portfolio?

A. Yes. The economic analysis among all nine price-policy scenarios was refreshed to reflect this updated bid portfolio, representing the 2017R RFP final shortlist, with corrected cost-and-performance inputs. This analysis was updated using the SO model and PaR. I describe the Company's updated economic analysis, for the Combined Projects including the 2017R RFP final shortlist, later in my testimony.

Q. Did the Company inform the Utah and Oregon IEs of changes to the 2017R RFP final shortlist resulting from the corrections applied to the modeling described above?

A. Yes. When issues related to the application of net-capacity factor adjustments and the omission of sales tax in the economic analysis were discovered, the Company notified the Utah and Oregon IEs to explain the impact on the 2017R RFP final shortlist and the impact on the economic analysis.

Q. Did the Oregon IE request any additional sensitivity studies during its review of the 2017R RFP final shortlist analysis?

A. Yes. As I will address more fully later in my testimony, the Company's bid-selection modeling, performed using the SO model and PaR, reflects nominal federal PTC inputs, to be consistent with how federal PTC benefits will flow into customer rates, where applicable, rather than levelized federal PTC inputs. To understand the impact of this assumption on bid selections, the Oregon IE requested that the Company produce an SO model sensitivity, with levelized PTCs, using medium natural gas price and medium CO_2 price assumptions to understand how treatment of federal PTCs affects bid selection. The Utah IE also expressed interest in seeing this sensitivity.

Q. What were the findings from this IE sensitivity?

A. When federal PTCs applicable to BTA bids and benchmark bids are levelized, the SO model replaces two BTA bids and a benchmark bid with two PPA bids. The PVRR(d) net benefits in the IE sensitivity, calculated from projected system costs through 2036 from the SO model, are lower in the IE sensitivity than they are in the economic analysis using the 2017R RFP final shortlist. In reviewing these results with the IEs, the Company also highlighted that the bid portfolio in the IE sensitivity produces higher nominal costs when compared to the economic analysis based on the 2017R RFP final shortlist.

Q. Did the Company change its 2017R RFP final shortlist based on the IE sensitivity?

A. No. While the IE sensitivity shows a change in the bid portfolio, this portfolio is selected based on federal PTC inputs that are inconsistent with how PTC benefits will be treated in customer rates. Moreover, the net benefits from the bid portfolio in the IE sensitivity produce lower PVRR(d) benefits and lower near-term nominal net-benefits than the bid portfolio reflected in the 2017R RFP final shortlist.

Q. Please describe the final shortlist of winning bids from the 2017R RFP.

A. The 2017R RFP final shortlist includes four new wind projects located in Wyoming from three different bidders. The total capacity of the four projects is 1,170 MW. The projects included in the final shortlist are summarized in Table 1-SD.

Table 1-SD. 2017R RFP Final Shortlist Projects

Project Name (Bidder)	Location	Capacity (MW)
TB Flats I & II (PacifiCorp)	Carbon & Albany Counties, WY	500
Cedar Springs (NextEra Energy	Converse County, WY	400
McFadden Ridge II (PacifiCorp)	Carbon & Albany Counties, WY	109
Uinta (Invenergy Wind	Uinta County, WY	161

Q. Are any of the winning bids the Company's benchmark resources?

A. Yes. The TB Flats I and II and McFadden Ridge II projects are Company-benchmark resources that will be developed under engineer, procure, and construction ("EPC") agreements. The Uinta project is being developed by Invenergy Wind Development under BTA. The Cedar Springs project is being developed by NextEra Energy Acquisitions as a 50-percent BTA and a 50-percent PPA. In total, the final shortlist includes 361 MW that will be developed under BTAs, 609 MW of benchmark capacity that will be developed under EPC agreements, and 200 MW that will deliver energy and capacity under a PPA.

Q. Please summarize the cost-and-performance attributes of the winning bids.

A. The total in-service capital cost for the winning bids is $1.30 billion, down from the $1.37 billion assumed in the Company's initial filing. Considering that the winning bids represent an increase in total owned-wind capacity (from just over 860 MW in the Company's initial filing to approximately 970 MW), the per-unit capital cost for final shortlist bids is down approximately 17 percent from $1,590/kW to $1,320/kW.

In addition to these capital costs, the PPA price that will be paid to NextEra Energy Acquisitions for 50 percent of the output from the Cedar Springs project is expected to add approximately [redacted] to total-system NPC [redacted] These costs are significantly lower than proxy PPA costs that were based off of certain QF projects that were included in the Company's initial filing, which were assumed to add [redacted] to total-system NPC beginning 2022, rising to [redacted] by the end of 2041. This proxy QF project, which requires interconnection facilities beyond the Aeolus-to-Bridger/Anticline transmission line that cannot be built until 2024, is no longer included in the Company's economic analysis of the Combined Projects.

In aggregate, the winning bids are expected to operate at a capacity-weighted average-annual capacity factor of 40.3 percent.

The in-service cost for network upgrades required to interconnect the final shortlist projects total [redacted] and the cost to build the Aeolus-to-Bridger/Anticline transmission line remains at [redacted]. The expected cost-and-performance attributes for the winning bids and the Transmission Project is summarized in more detail in Confidential Exhibit RMP__(RTL-1SD).

Q. How did the Company verify the forecasted capacity factors in its review of bids during the 2017R RFP?

A. The Company retained an independent third-party expert, Sapere Consulting, to evaluate the capacity factors proposed for each bid selected to the initial shortlist. Sapere Consulting's report is attached as Confidential Exhibit RMP__(RTL-2SD).

Q. Did the Company adjust any of the performance data for bids included in the initial shortlist based on the report prepared by Sapere Consulting?

A. Yes. Consistent with recommendations from Sapere Consulting, the net capacity factor for the [redacted] bids were assessed at 92 percent of the net capacity factor proposed by [redacted] No adjustments were applied to any of the other bids.

Q. As part of the 2017R RFP process, did the Company perform any preliminary viability assessments for the projects included in the final shortlist?

A. Yes. The Company reviewed each project's place in the transmission interconnection queue and how each project will qualify for federal PTCs. The Company also reviewed bid materials to evaluate site control, progress in collecting avian data, and permitting timelines. All of the projects have either initiated or received system impact studies and are expected to be able to execute interconnection agreements that support the proposed commercial operation dates. All of the projects will qualify for the full value of PTCs by having secured safe-harbor equipment and by meeting continuity-of-construction requirements, as described in Ms. Nikki L. Kobliha's testimony, by coming online by the end of 2020. All of the final shortlist projects have demonstrated they have site control, have reasonable permitting timelines that will allow the projects to be place in service by the end of 2020 and have initiated collection of avian data.

Q. What is the status of the 2017S RFP?

A. The Company received initial bids for new solar resources on December 11, 2017. On

January 8, 2018, PacifiCorp established an initial shortlist, considering both price and non-price scoring elements, which was subsequently submitted to the Solar RFP IE for review. As was the case with the 2017R RFP, the market response to the 2017S RFP was robust. The Company received solar resource proposals from 31 bidders offering 109 bid alternatives for 46 solar projects. In aggregate, 6,496 MW of new solar resource capacity was bid into the 2017S RFP. After completing its bid-eligibility screening, a process that ensures all bids satisfy minimum-bid requirements that are specified in the 2017S RFP, the Company disqualified 32 bid alternatives, which equates to 3,039 MW of new solar resource capacity.

Q. Did the Company review those bid alternatives that did not meet minimum-bid requirements with the Solar RFP IE?

A. Yes. The Solar RFP IE reviewed the Company's minimum-eligibility criteria and determined that these criteria are consistent with other renewable resource RFPs. The Solar RFP IE also reviewed the specific bid alternatives that were disqualified, and in all instances, found that the disqualified bids clearly did not meet the minimum-eligibility criteria listed in the RFP.

Q. Has the Solar RFP IE commented on any other elements of the on-going RFP process?

A. Yes. On January 10, 2018, the Solar RFP IE submitted its first status report, where it concluded that the 2017S RFP documents are clear and the 2017S RFP has been conducted in a clear and transparent manner.

Q. Please summarize the bids selected to the initial shortlist from the 2017S RFP.

A. The 2017S RFP initial shortlist includes PPAs bids from 10 projects proposed by seven bidders totaling 1,629 MW. The majority of the projects (1,414 MW) are located in Utah, and the remaining initial shortlist bids are located in Oregon (114 MW) and Washington (100 MW). All of the bids on the 2017S RFP initial shortlist have proposed PPAs with commercial operation dates ranging between November 2020 and January 2021– approximately one year before the initial ramp down in investment-tax credits.

Q. Has the Company determined whether it will pursue any bids from the 2017S RFP?

A. No. The Company continues to evaluate potential bids in the 2017S RFP and has not yet established a final shortlist. There are several outstanding milestones that have to be met before establishing a final shortlist. Under the 2017S RFP schedule, the Solar RFP IE will complete its review of the initial shortlist no later than January 29, 2018, and then bidders will be asked to submit best-and-final pricing no later than February 5, 2018. Once best-and-final pricing is received, the Company plans to identify a final shortlist by mid-March 2018.

Q. Has the Company analyzed how the potential selection of bids from the 2017S RFP might affect the economic analysis of the 2017R RFP final shortlist?

A. Yes. Using cost-and-performance data from the bids submitted into the 2017S RFP, the Company has analyzed how the potential selection of these bids would impact the economic analysis of the winning bids from the 2017R RFP. I describe this sensitivity analysis later in my testimony.

UPDATED ECONOMIC ANALYSIS

Q. What assumptions did the Company update before refreshing its economic analysis of the Combined Projects?

A. The models were updated to reflect: (1) cost-and-performance assumptions for the Wind Projects consistent with the winning bids selected to the 2017R RFP final shortlist as summarized earlier in my testimony; (2) current load-forecast projections; (3) current price-policy scenario assumptions; and (4) recent changes in federal tax rate for corporations.

Q. Please describe the updated cost-and-performance estimates for the Wind Projects.

A. The updated economic analysis includes the capital costs associated with the winning bids, the costs associated with the Cedar Springs PPA, and the updated net capacity factors, as described above. The updated economic analysis also captures terminal-value benefits from BTA and EPC-benchmark bids, where the Company retains control of the site at the end of the asset life. These benefits were considered in the 2017R RFP bid-selection process, consistent with the bid-evaluation methodology described in the RFP, and therefore, they are applied in the updated economic analysis.

Q. What is captured by the terminal value applied to BTA and EPC-benchmark bids?

A. When a wind asset reaches the end of its life (assumed to be 30 years), equipment associated with the wind asset itself has been fully depreciated. However, transmission assets required to interconnect the wind facility have a longer life (assumed to be 62 years). At the time the wind asset reaches the end of its life, the transmission assets required for interconnection have approximately 32 years of additional life remaining.

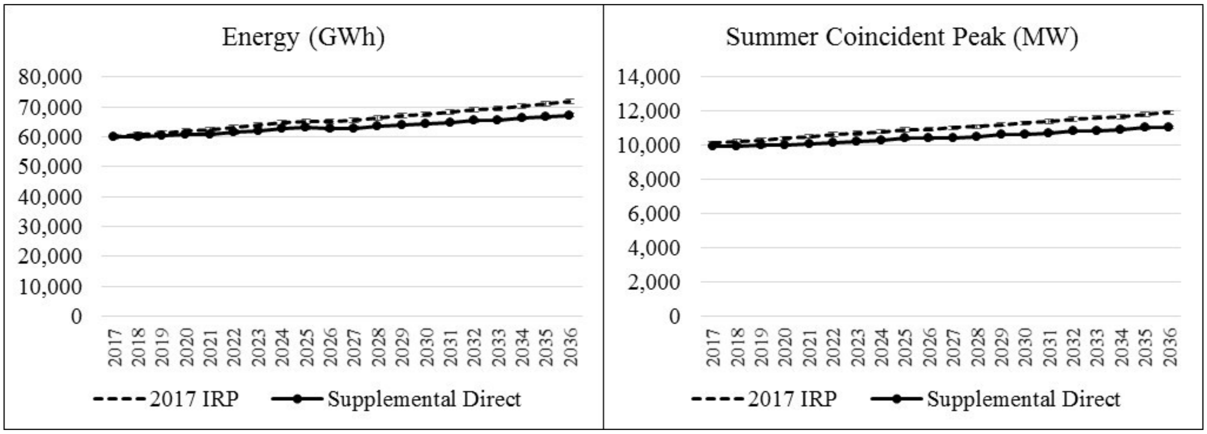
With an owned-wind facility where the Company retains control of the site, whether developed as a BTA or an EPC-benchmark, that site can be redeveloped using existing transmission assets that have not been fully depreciated. Consequently, relative to the future development of a new greenfield wind project, the redevelopment of an existing site limits incremental transmission interconnection costs. Similarly, with an owned facility, an existing site can be redeveloped with limited incremental project-development costs, thereby reducing the cost to acquire development rights relative to a new site. These terminal-value benefits are not applicable to a PPA bid, where a third-party retains control of the site.

Q. Please describe the new load forecast assumptions included in the updated economic analysis.

A. The load forecast used in the economic analysis summarized in my direct testimony is the same load forecast used in PacifiCorp's 2017 IRP. This 2017 IRP load forecast was finalized in December 2016. The updated economic analysis uses the Company's new load forecast completed in the summer of 2017, after the Company made its initial filing.

Figure 1-SD compares the load forecast from the 2017 IRP used in my original economic analysis to the new load forecast. The updated system energy forecast is down by 2.2 percent in 2021 and down by 6.3 percent in 2036 relative to the 2017 IRP forecast. The updated coincident summer peak forecast is down by 4.1 percent in 2021 and down by 7.2 percent in 2036 relative to the 2017 IRP forecast.

Figure 1-SD. Comparison of the 2017 IRP and Updated Load Forecast Assumptions



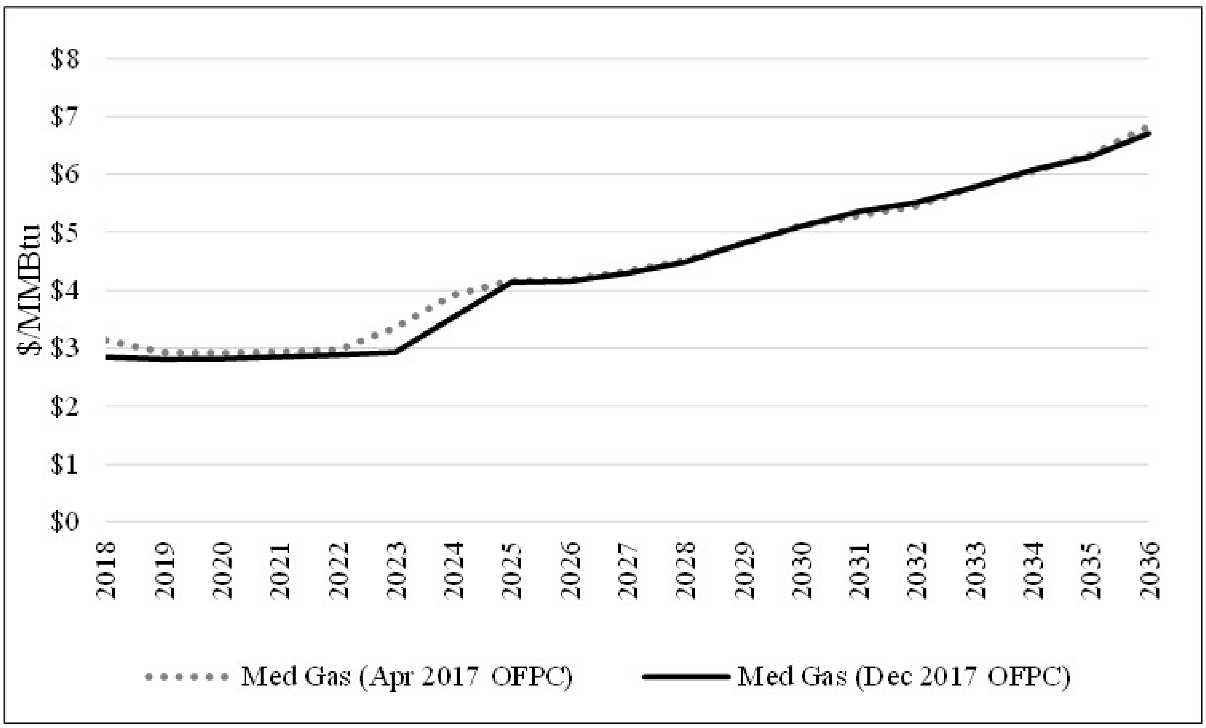
Changes in the load forecast are primarily driven by: (1) a reduction in Utah and Wyoming industrial loads principally due to reduced usage projections for a number of large customers; (2) increases in the growth of customer generation from 2017 to 2018, contributing to reductions in Utah residential customer usage; and (3) updated appliance saturation and efficiency assumptions with refinements to miscellaneous device sales data (*i.e.*, televisions, pool heaters, personal computers, and other plug-in devices), contributing to reductions in Utah residential customer usage.

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

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

The Company's most recent OFPC is dated December 30, 2017, which reflects more current market forwards and an updated forecast from [redacted] Figure 2-SD compares Henry Hub natural-gas prices from the April 26, 2017 OFPC, as used to support the economic analysis in my direct testimony, with Henry Hub natural-gas prices from the updated December 30, 2017 OFPC. Over the period 2018 through 2036 and using the most current discount rate, the nominal levelized price for Henry Hub natural-gas prices has decreased by approximately three percent from $4.06/MMBtu to $3.94/MMBtu. .

Figure 2-SD. Comparison of the April 2017 and December 2017 OFPC Henry Hub Natural Gas Price Forecasts



The updated OFPC reflects market forwards as of December 30, 2017 over the period January 2018 through January 2024. The decrease in levelized prices between the updated OFPC and the April OFPC used in the Company's original economic analysis is primarily driven by a reduction in market forwards. Prices in the updated market fundamentals forecast from [redacted], which are used exclusively in the OFPC beyond January 2025, track closely with those assumed in the April 2017 OFPC.

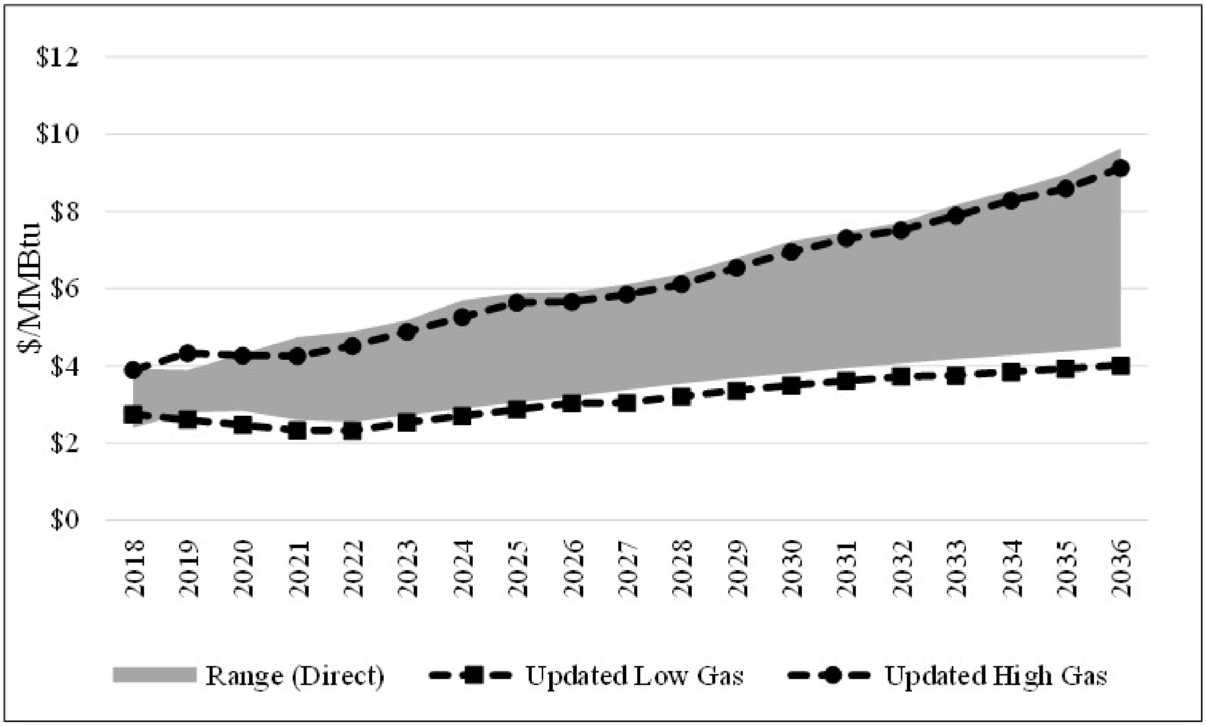
The Company continues to blend market forwards from month 61 (February 2023) through month 72 (January 2024) with the fundamentals-based forecast from month 85 (February 2025) through month 96 (January 2026) to establish prices in month 73 (February 2024) through month 84 (January 2025).

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

A. Yes. Consistent with the Company's approach to develop low and high natural-gas price scenarios used in the original economic analysis, low and high natural-gas price assumptions were updated after reviewing the range in more recent forecasts developed by [redacted], [redacted] and the U.S. Department of Energy's Energy Information Administration. Exhibit RMP__(RTL-3SD) shows the range in natural-gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios in the Company's updated economic analysis of the Combined Projects.

Figure 3-SD shows the range between the low and high natural-gas price scenarios used in the Company's original economic analysis alongside the updated low and high natural-gas price assumptions. Nominal levelized prices in the low and high scenarios are $2.95/MMBtu (down by approximately seven percent) and $5.60/MMBtu (down by approximately four percent), respectively.

Figure 3-SD. Updated Low and High Natural-Gas Price Assumptions



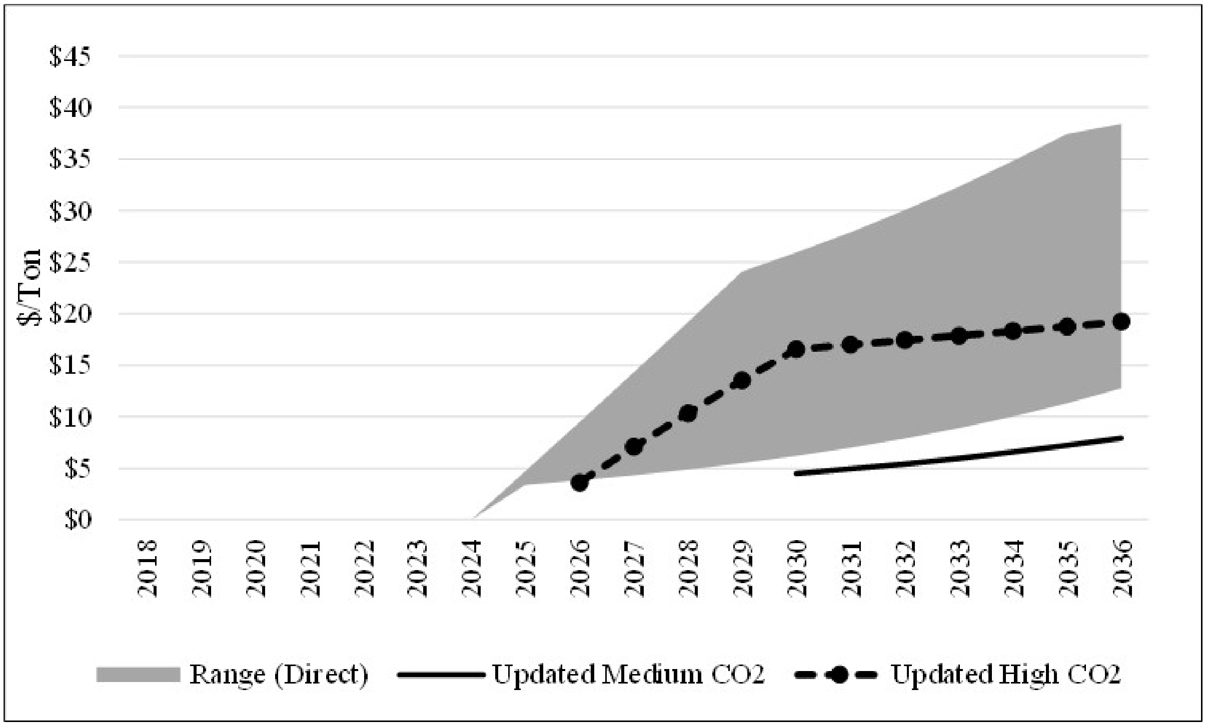
Q. Did the Company update its CO_2 price scenarios used in its updated economic analysis?

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

Figure 4-SD shows the range between the medium and high CO_2 price scenarios used in the Company's original economic analysis alongside the updated medium and high CO_2 price assumptions. The updated medium and high CO_2 price assumptions are

lower and start later relative to the assumptions summarized in my direct testimony. Updated CO_2 prices in the medium scenario begin in 2030 (five years later) at $4.49/ton and rise to $7.95/ton by 2036. Updated prices in the high scenario begin in 2026 (one year later) at $3.62/ton, rise to $16.55/ton by 2030, and reach $19.23/ton by 2036.

Figure 4-SD. Updated Medium and High CO_2 Price Assumptions



Q. Please describe the updated federal tax rate for corporations that was included in the updated economic analysis of the Combined Projects.

A. The Company's updated analysis assumes a 21 percent federal income tax rate. Based on an assumed net state income tax rate of 4.54 percent, the effective combined federal and state income tax rate used in the updated analysis is 24.587 percent.

Q. Please describe how the effective combined federal and state income tax rate assumption is applied in the SO model and PaR in the updated economic analysis.

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

The modified income tax rate also affects the capital revenue requirement for all new resource options available for selection in the SO model, including the selection of bids from the 2017R RFP. As described in my direct testimony, capital revenue requirement is levelized in the SO and PaR models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. This is achieved through annual capital recovery factors, which are expressed as a percentage of the initial capital investment for any given resource alternative in any given year. Capital recovery factors, which are based on the revenue requirement for specific types of assets, are differentiated by each asset's assumed life, book-depreciation rates, and tax-depreciation rates. Because capital revenue requirement accounts for the impact of income taxes on rate-based assets, the capital recovery factors applied to new resource costs in the SO model were updated for each of the Company's system simulations.

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

PTC-eligible resource alternatives available in the SO model.

Q. How were these assumption updates captured in the updated economic analysis of the Combined Projects?

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

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

A. Yes. When establishing the 2017R RFP final shortlist, the Company applied PTC benefits for applicable bids (BTAs and benchmark-EPC bids) on a nominal basis rather than on a levelized basis. This approach better reflects how the federal PTC benefits for these bids will flow through to customers and aligns the treatment of federal PTC benefits in the system modeling results extending out through 2036 with the nominal revenue requirement results extending out through 2050. It also ensures the 2017R RFP bid selections from the SO model more accurately reflect the difference in how BTA and benchmark-EPC bids are expected to impact customer rates.

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

configured to forecast system costs through 2036?

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

UPDATED SYSTEM MODELING PRICE-POLICY RESULTS

Q. Please summarize the updated PVRR(d) results calculated from the SO model and PaR through 2036.

A. Table 2-SD summarizes the updated PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without the Combined Projects, reflecting winning bids from the 2017R RFP, are shown for the SO model and for PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP___(RTL-4SD).

Table 2-SD Updated SO Model and PaR PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO2	$(145)	$(104)	$(109)
Low Gas, Medium CO2	$(186)	$(124)	$(131)
Low Gas, High CO2	$(297)	$(258)	$(272)
Medium Gas, Zero CO2	$(306)	$(246)	$(258)
Medium Gas, Medium CO2	$(343)	$(311)	$(327)
Medium Gas, High CO2	$(430)	$(388)	$(406)
High Gas, Zero CO2	$(619)	$(509)	$(535)
High Gas, Medium CO2	$(636)	$(539)	$(567)
High Gas, High CO2	$(696)	$(605)	$(636)

Over a 20-year period, the Combined Projects reduce customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) net benefits range between $311 million, when derived from PaR stochastic-mean results, and $343 million, when derived from SO model results.

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

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

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

A. Yes. Consistent with my direct testimony, the PVRR(d) results presented in Table 2-SD do not reflect the potential value of RECs generated by the incremental energy output from the Wind Projects. Accounting for the updated performance estimates discussed above, customer benefits for all price-policy scenarios would improve by approximately $31 million for every dollar assigned to the incremental RECs that will be generated from the Wind Projects through 2036 (up from $26 million in my original analysis). Quantifying the potential upside associated with incremental REC revenues is simply intended to simply communicate that the net benefits from the Combined Projects could improve if the incremental RECs can be monetized in the market.

Q. Is there additional upside to the net benefits shown in Table 2-SD?

A. Yes. Before receiving bids submitted into the 2017R RFP, the Company locked down with the IEs default operations and maintenance (“O&M”) assumptions that were applied to BTA and benchmark-EPC bids beyond proposed O&M agreement periods. These assumptions were based on the Company's experience in operating and maintaining the existing fleet of owned-wind facilities and were used in the bid-selection process and the economic analysis summarized above.

Since construction of the Company's existing fleet of wind facilities, wind technology has evolved and turbine sizes have increased. With the increase in turbine size, O&M costs are expected to be lower than actual experience because there are fewer turbines on a given site. The range in cost savings is expected to vary between 31 to 42 percent of certain O&M cost elements (*i.e.*, materials and O&M contract costs). Two of the winning bids–Invenergy Wind Development's Uinta project and PacifiCorp's TB Flats I and II project–will use larger-turbine equipment for a portion of the wind turbines on each site. If the O&M cost elements applicable to the larger-turbine equipment are reduced by 42 percent, which is equivalent to an approximately 18 percent reduction in total O&M costs, beyond the proposed O&M agreement period, customer benefits calculated through 2036 for all price-policy scenarios would improve by approximately $13 million.

UPDATED REVENUE REQUIREMENT MODELING PRICE-POLICY RESULTS

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

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

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

A. Table 3-SD summarizes the updated PVRR(d) results for each price-policy scenario calculated off of the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit RMP__(RTL-5SD).

Table 3-SD. Updated Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO2	$169
Low Gas, Medium CO2	$133
Low Gas, High CO2	$(105)
Medium Gas, Zero CO2	$(60)
Medium Gas, Medium CO2	$(177)
Medium Gas, High CO2	$(301)
High Gas, Zero CO2	$(437)
High Gas, Medium CO2	$(479)
High Gas, High CO2	$(585)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned-wind projects included in the 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios. Customer benefits, range from $60 million in the medium natural gas, zero CO_2 scenario to $585 million in the high natural gas, high CO_2 scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits of the Combined Projects are $177 million. The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas prices are paired with zero or medium CO_2 prices. These results show that upside benefits far outweigh downside risks.

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

A. Yes. Consistent with my direct testimony, the PVRR(d) results presented in Table 3-SD do not reflect the potential value of RECs generated by the incremental energy output from the Wind Projects. Accounting for the updated performance, customer benefits for all price-policy scenarios would improve by approximately $39 million for every dollar assigned to the incremental RECs that will be generated from the Wind Projects through 2050 (up from $34 million in my original analysis).

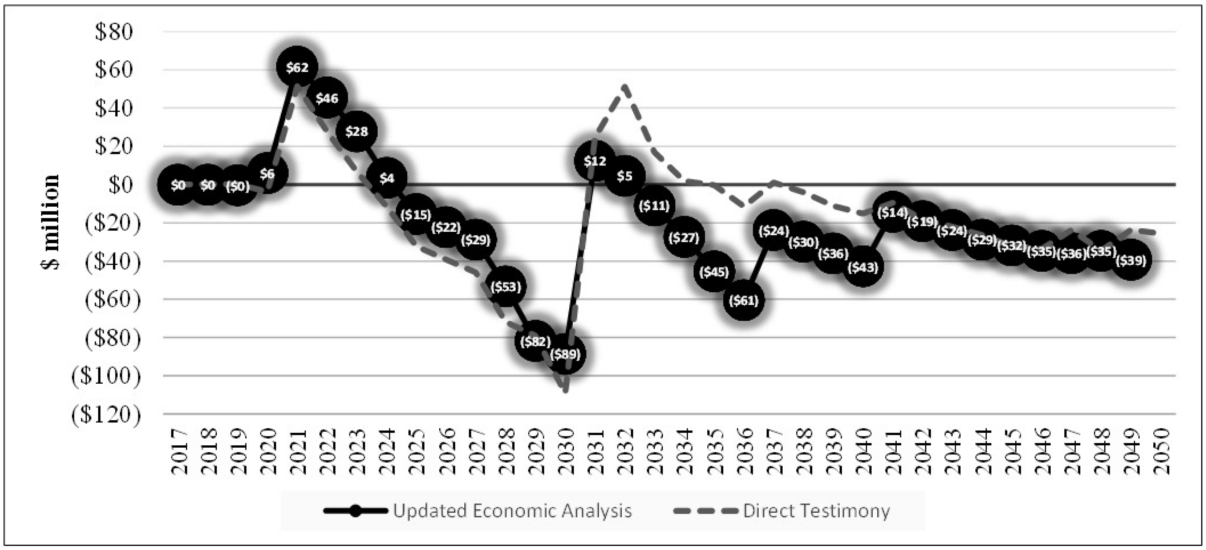
Q. Is there additional potential upside to these PVRR(d) results associated with reduced O&M costs?

A. Yes. As discussed above, the Company anticipates O&M costs for those projects that will install larger turbine equipment to be lower than what has been reflected in the updated economic analysis. Accounting for these cost savings, customer benefits for all price-policy scenarios would improve by approximately $22 million when calculated from projected operating costs through 2050.

Q. Please describe the change in annual nominal revenue requirement from the Combined Projects.

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

Figure 5-SD Updated Total-System Annual Revenue Requirement
With the Combined Projects (Benefit)/Cost ($ million)



The data shown in this figure for the updated economic analysis have the same basic profile as the data from the original economic analysis summarized in my direct testimony. This profile shows that despite a reduction in PTC benefits associated with changes in federal tax law, the reduced costs from winning bids from the 2017R RFP continue to generate substantial near-term customer benefits, reduce the magnitude and shorten the duration over which costs increase after federal PTCs for new wind resources expire, and continue to contribute to customer benefits over the long-term.

The year-on-year reduction in net benefits from 2036 to 2037 is driven by the Company's conservative approach to extrapolate benefits from 2037 through 2050 based on modeled results from the 2028 through 2036 timeframe. This leads to an abrupt reduction in the benefits in 2037, and a subsequent year-on-year reduction to net benefits, which breaks from the trend observed in the model results over the 2033 to 2036 time frame, This extrapolation methodology is conservative because it results in project benefits not matching the levels observed in the model results for 2036 until 2044.

SOLAR SENSITIVITY

Q. Please describe the sensitivity studies that analyzed the impact of the solar bids received in the 2017S RFP on the economics of the Combined Projects.

A. The Company's solar sensitivity analysis used the SO model and PaR simulations to determine the PVRR(d) based on two model runs–one with solar PPA bids and the Combined Projects and one with solar PPA bids but without the Combined Projects. In the sensitivity where PPA bids are pursued with the Combined Projects, the SO model continues to choose the winning bids included in the 2017R RFP final shortlist as part of the least-cost bid portfolio. Depending upon the price-policy scenario, between 1,118 MW and 1,315 MW of solar PPA bids, from new projects all located in Utah, are added to the system by the SO model.

Q. What were the results of the solar sensitivity where solar PPA bids are assumed to be pursued in lieu of the Combined Projects?

A. Table 4-SD summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued without any investments in the Combined Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined

Projects were evaluated without solar PPA bids.

Table 4-SD Solar Sensitivity with Solar PPAs Included in lieu of the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	$(334)	$(343)	$9
PaR Stochastic Mean	$(203)	$(311)	$108
PaR Risk Adjusted	$(213)	$(327)	$114
Low Gas, Zero CO2			
SO Model	$(206)	$(145)	$(61)
PaR Stochastic Mean	$(126)	$(104)	$(22)
PaR Risk Adjusted	$(133)	$(109)	$(24)

In the medium natural gas, medium CO_2 price-policy scenario, a portfolio with the Combined Projects delivers greater customer benefits relative to a portfolio that adds solar PPA bids without the Combined Projects. Customer benefits are greater when the resource portfolio includes the Combined Projects without solar PPA bids by $114 million in the medium natural gas, medium CO_2 price-policy scenario based on the risk-adjusted PaR results. In the low natural gas, zero CO_2 price-policy scenario, the portfolio with solar PPA bids and without the Combined Projects has higher net customer benefits relative to a portfolio containing just the Combined Projects. The increase in net benefits in the solar PPA portfolio is $24 million based on the risk-adjusted PaR results.

Q. What were the results of the solar sensitivity where solar PPA bids are pursued with the Combined Projects?

A. Table 5-SD summarizes PVRR(d) results for the solar sensitivity where solar PPA bids are assumed to be pursued along with the proposed investments in the Combined

Projects. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without solar PPA bids.

Table 5-SD Solar Sensitivity with Solar PPAs Included With the Combined Projects (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	$(602)	$(343)	$(259)
PaR Stochastic Mean	$(442)	$(311)	$(131)
PaR Risk Adjusted	$(464)	$(327)	$(137)
Low Gas, Zero CO2			
SO Model	$(286)	$(145)	$(141)
PaR Stochastic Mean	$(185)	$(104)	$(81)
PaR Risk Adjusted	$(195)	$(109)	$(86)

When the solar PPAs are pursued in addition to the Combined Projects, the total benefits increase, but are diluted (*i.e.*, the aggregate net benefits are less than the sum of the benefits for the cases where Combined Projects or solar PPAs are pursued independently).

Q. What conclusions can you draw from these solar sensitivity analyses?

A. These sensitivities demonstrate that should the Company choose to pursue solar bids through the 2017S RFP, the resulting solar PPAs would not displace the Combined Projects as an alternative means to deliver economic savings for customers.

While the sensitivity with a portfolio containing solar PPAs without the Combined Projects produces a PVRR(d) with net benefits that are slightly higher than a portfolio without the solar PPAs in the low natural-gas, zero CO2 price-policy scenario, both portfolios deliver customer benefits. This sensitivity does not support an alternative resource procurement strategy to pursue solar PPA bids in lieu of the Combined Projects. This would leave the significant benefits from the Combined Projects, which include building a much-needed transmission line, on the table. Importantly, the sensitivity that evaluates the Combined Projects with the solar PPAs produces net benefits that are greater than the net benefits from the Combined Projects without the solar PPAs. This confirms that near-term renewable procurement is not a matter of whether the company should pursue the Combined Projects or the solar PPAs, but whether the company should consider both opportunities. At this time, it is clear that the Combined Projects provide significant net benefits, and that these benefits are not eliminated if the company were to also pursue solar PPA bids through the 2017S RFP.

WIND REPOWERING SENSITIVITY

Q. Has the Company updated its sensitivity analysis related to the wind repowering project?

A. Yes. Based on the updates discussed above, coupled with the updated cost-and performance-estimates for the wind repowering project (described in Docket No. 20000-519-EA-17), the Company performed a sensitivity that includes the repowered wind facilities assuming they continue to operate within the limits of their large generator interconnection agreements ("LGIAs").

Q. What were the results of the wind-repowering sensitivity?

A. Table 6-SD summarizes PVRR(d) results for this wind-repowering sensitivity. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural gas, medium CO_2 and the low natural gas, zero CO_2 price-policy scenarios. The results are shown alongside the benchmark study in which the Combined Projects were evaluated without wind repowering.

Table 6-SD Wind-Repowering Sensitivity (Benefit)/Cost ($ million)

	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO2			
SO Model	$(541)	$(343)	$(198)
PaR Stochastic Mean	$(475)	$(311)	$(164)
PaR Risk Adjusted	$(498)	$(327)	$(171)
Low Gas, Zero CO2			
SO Model	$(313)	$(145)	$(169)
PaR Stochastic Mean	$(255)	$(104)	$(152)
PaR Risk Adjusted	$(268)	$(109)	$(159)

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

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

A. The results of the 2017R RFP confirm that the Combined Projects are the least-cost, least-risk customer resources available to serve the Company's customers. The substantial volume of bids into the 2017R RFP produced competitive project costs, allowing the Company to obtain greater wind generating capacity at lower overall capital costs, with increased net benefits for customers. The Combined Projects show net customer benefits under all price-policy scenarios through 2036 and in seven of nine scenarios through 2050. The Company's updated sensitivities further demonstrate that the Combined Projects are not displaced by solar resources that bid into the 2017S RFP, and that the economics of the Combined Projects become more favorable when combined with wind repowering.

Q. Does this conclude your supplemental direct testimony?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND NONTRADITIONAL RATEMAKING FOR WIND AND TRANSMISSION FACILITIES	)))))))	DOCKET NO. 20000-520-EA-17 (RECORD NO. 14781)

AFFIDAVIT, OATH AND VERIFICATION

Rick T. Link (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the Vice President for PacifiCorp, which is a party in this matter.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in his official capacity as Vice President.

Further Affiant Sayeth Not.

Dated this 12th day of January, 2018

Rick T. Link
Vice President
825 NE Multnomah St.
Portland, OR 97232
(503) 813-7163

STATE OF OREGON)
) SS:
COUNTY OF MULTNOMAH)

The foregoing was acknowledged before me by Rick T. Link on this 12th day of January, 2018. Witness my hand and official seal.

Notary Public

My Commission Expires: 10/26/2021

OFFICIAL STAMP
KELLY ANN WIGGINS
NOTARY PUBLIC-OREGON
COMMISSION NO. 968113
MY COMMISSION EXPIRES OCTOBER 26, 2021