ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 310
Salt Lake City, Utah 84114

VIA ELECTRONIC FILING

August 31, 2017

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. 17-035-23 In the Matter of the Application of Rocky Mountain Power for Approval of Solicitation Process for Wind Resources

Pursuant to Utah Public Service Commission order dated August 29, 2017, in the above referenced matter, the Company hereby submits for electronic filing its Supplemental Testimony. The filing consists of the testimony and exhibits of one witness.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding these filings be addressed to the following:

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Informal inquiries may be directed to Bob Lively at (801) 220-4052.

Sincerely,

Jeffrey K. Larsen

Jeffrey K. Larsen
Vice President, Regulation

Rocky Mountain Power
Docket No. 17-035-23
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Supplemental Testimony of Rick T. Link

August 2017

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

A. Yes.

TESTIMONY PURPOSE

Q. What is the purpose of your testimony?

A. My testimony responds to the August 22, 2017 Order and Notice of Scheduling Conference ("Order") issued by the Public Service Commission of Utah ("Commission") in which it expressed concern about an insufficient record upon which to make a determination on the company's 2017 Renewable Resources Request for Proposals ("2017R RFP"). The 2017R RFP seeks up to approximately 1,270 MW of new wind resources capable of interconnecting to PacifiCorp's transmission system in Wyoming ("Wyoming wind").

Specifically, my testimony supplements the record and demonstrates that 1) the 2017R RFP for Wyoming wind will produce a resource that meets the "lowest reasonable cost" standard; 2) we have revised the 2017R RFP in response to input from stakeholders and the independent evaluator ("IE") to ensure robust market participation; 3) approval to the 2017R RFP will not prejudge other related regulatory proceedings; and 4) the Commission and stakeholders will have additional opportunities to weigh in on the company's acquisition of Wyoming wind resources. I believe that the information in this testimony, along with the information that has already been submitted in this docket, will allow the Commission to conclude that the company's 2017R RFP "will most likely result in the acquisition, production, and delivery of electricity at the lowest reasonable cost to the retail customers of an affected electrical utility located in this state," as required by Utah Code § 54-17-201(2)(c)(ii)(A).

THE 2017R RFP PROCEDURAL SCHEDULE

Q. Is the company requesting a Commission decision within a certain timeframe?

A. Yes. We respectfully request that the Commission issue an order at the conclusion of the hearings, but no later than September 25, 2017, approving the company's solicitation process. Utah Code Ann § 54-17-201 requires that the Commission issue an order within 60 days of the filing of an RFP. The original schedule established in this proceeding already provided one additional week beyond the 60-day statutory timeline, and the additional process arising from the Order could add another five weeks to the schedule. As a result, the remaining 2017R RFP schedule must be compressed by shortening the time between issuing the 2017R RFP to market and establishing the final shortlist of bids by early January 2018. The timing of the shortlist is critical to informing the Utah preapproval filing and the certificate of public convenience and necessity approval processes in Idaho and Wyoming.

Q. Have any other state commissions approved the 2017R RFP?

A. Yes. At a special public meeting held August 29, 2017, the Public Utility Commission of Oregon ("Oregon Commission") conditionally approved the 2017R RFP with certain modifications. While a written order has not been issued as of the filing date of this testimony, the Oregon Commission held that the RFP is approved as modified, but conditioned the approval order on acknowledgment of the related action items in the 2017 Integrated Resource Plan ("IRP"), which will be considered by the Oregon Commission in November 2017. As part of that approval, the company also agreed to modify the 2017R RFP document and evaluation process in response to several items proposed by the Oregon IE. Those modifications include:

1. Expansion of the 2017R RFP repowered project eligibility. An existing wind project that currently has a power purchase agreement ("PPA") with PacifiCorp that will expire before December 31, 2020, will be eligible to bid into the 2017R RFP if the project is proposed to be repowered.

2. Clarification of the 2017R RFP to state that benchmark bids are responsible for a Success Fee if selected to the final short list. PacifiCorp will clarify in its 2017R RFP that all benchmark and market bids will be responsible for all appropriate bidder fees through the full RFP process including any Success Fees assigned to the final short list bids in the 2017R RFP.

3. Modification of the 2017R RFP minimum qualification requirements regarding litigation. PacifiCorp will modify item 8 under Section 6.H to be consistent with what was used in the final draft of PacifiCorp's All Source RFP for a 2016 Resource issued April 4, 2012. The Oregon Commission determined that there should be a materiality threshold of $5 million and the Oregon IE should use discretion in its assessment of any determination to exclude a bid due to litigation. PacifiCorp expects the Oregon Commission to provide guidance regarding specific litigation language in its written order.

THE 2017R RFP FOR WYOMING WIND WILL PRODUCE A RESOURCE THAT MEETS THE LOWEST REASONABLE COST STANDARD

Q. Please describe your understanding of the Commission's concerns as described in the Order.

A. The Commission concluded that it needed additional information to determine whether "the decision to limit the RFP to a wind resource so apparently satisfies the 'lowest reasonable cost' standard that it warrants bypassing the opportunity to test that decision in the open market against other bidders who might choose to bid different resource types."[1]

[1] Order at 2-3.

Q. Has the company analyzed whether the Wyoming wind projects identified in the 2017R RFP will meet the "lowest reasonable cost" standard?

A. Yes. The August 2, 2017 informational update filed in the company's 2017 IRP proceeding in Docket No. 17-035-16 ("Energy Vision 2020 Update"), attached to this testimony as Exhibit RMP __ (RTL-S1), provides the most current economic analysis and related discussion regarding the benefits that will be provided by the Wyoming wind resources identified in the 2017R RFP, as I discuss in more detail below. The economic analysis summarized in the Energy Vision 2020 Update is identical to the economic analyses in the company's filings in Dockets No. 17-035-39 and No. 17-035-40.

This analysis, which uses proxy cost and performance assumptions for benchmark resources, demonstrates that customers are expected to realize significant net benefits from the proposed new wind and transmission projects. The 2017R RFP will solicit PPA and build-transfer agreement ("BTA") bids from market participants that will compete with benchmark bids. Upon receipt of bids, PacifiCorp will initiate a robust bid evaluation process, with oversight provided by the Utah and Oregon IEs, to identify the combination of market and benchmark bids that will maximize customer benefits. PacifiCorp will only execute agreements with bids selected to the final shortlist if those short-listed projects will deliver economic benefits for customers. Considering that benchmark bids will compete with PPA and BTA bids from other market participants and selection of these bids will be based on the combination of proposals that maximize customer benefits, the 2017R RFP is explicitly designed to deliver resources that meet the "lowest reasonable cost" standard.

Q. Does the economic analysis presented in PacifiCorp's Energy Vision 2020 Update consider a range of outcomes based on varying input assumptions?

A. Yes. The economic analysis supporting the new wind and transmission projects that is included in the Energy Vision 2020 Update considered nine scenarios with varying natural gas price and carbon dioxide ("CO_2") policy assumptions (price-policy scenarios). These two variables influence system variable costs, and so it is important to understand how these assumptions affect net power cost ("NPC") benefits expected from the new wind and transmission projects. The price-policy scenarios consider a range of natural gas price assumptions (low, medium, and high) and a range of CO_2 policy assumptions[2] implemented through an assumed CO_2 price forecast (zero, medium, and high).[3] Table 1 summarizes the nine price-policy scenarios used in the company's Energy Vision 2020 Update.

Table 1. Price-Policy Scenarios

Price-Policy Scenario	**Natural Gas Prices (Levelized $/MMBtu)***	**CO_2 Price Description**
Low Gas, Zero CO_2	$3.19	$0/ton
Low Gas, Medium CO_2	$3.19	$3.41/ton in 2025 growing to $14.40/ton in 2036
Low Gas, High CO_2	$3.19	$4.73/ton in 2025 growing to $38.42/ton in 2036
Medium Gas, Zero CO_2	$4.07	$0/ton
Medium Gas, Medium CO_2	$4.13	$3.41/ton in 2025 growing to $14.40/ton in 2036

[2] Each natural gas price scenario is accompanied by a unique and consistent forecast of wholesale power prices.
[3] Since PacifiCorp filed the 2017 IRP, it has become increasingly unlikely that the Clean Power Plan will be implemented in its current form. However, it is still possible that future CO_2 policies targeting electric sector emissions could be adopted and impose incremental costs to drive emission reductions.

Medium Gas, High CO_2	$4.13	$4.73/ton in 2025 growing to $38.42/ton in 2036
High Gas, Zero CO_2	$5.83	$0/ton
High Gas, Medium CO_2	$5.83	$3.41/ton in 2025 growing to $14.40/ton in 2036
High Gas, High CO_2	$5.83	$4.73/ton in 2025 growing to $38.42/ton in 2036

Q. What are the results from the economic analysis summarized in the Energy Vision 2020 Update?

A. Table 2 summarizes the present-value revenue-requirement differential (“PVRR(d)”) results for each price-policy scenario. The PVRR(d) between cases with and without the new wind and transmission projects are shown from the System Optimizer (“SO”) model and from the Planning and Risk model (“PaR”), which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). These are the same models used by PacifiCorp to evaluate resource portfolios over a 20-year forecast period (2017-2036) in the IRP. Over a 20-year period, the new wind and transmission projects reduce customer costs in seven out of nine price-policy scenarios.

Table 2. (Benefit)/Cost of New Wind and Transmission (2017-2036, $ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	$121	$77	$74
Low Gas, Medium CO_2	$73	$32	$26
Low Gas, High CO_2	($84)	($133)	($147)
Medium Gas, Zero CO_2	($19)	($57)	($66)
Medium Gas, Medium CO_2	($85)	($111)	($124)
Medium Gas, High CO_2	($156)	($224)	($242)
High Gas, Zero CO_2	($304)	($260)	($280)
High Gas, Medium CO_2	($318)	($272)	($293)
High Gas, High CO_2	($396)	($409)	($437)

The only price-policy scenarios without net customer benefits are those assuming the lowest natural-gas prices when paired with either medium or zero CO_2 price assumptions. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits range between \$85 million, when based upon SO model results, and \$124 million, when based upon PaR risk-adjusted results. The PVRR(d) results show that the benefits increase with natural gas prices and CO_2 prices, where the new wind and transmission projects help offset higher NPC and system emission costs.

Table 3 shows PVRR(d) results when the analysis is expanded through 2050, which covers the 30-year life of the new wind resources. As is the case with results based on forecasted system costs through 2036, when the analysis is extended over a longer time frame, the new wind and transmission reduce customer costs in seven out of nine price-policy scenarios. The only price-policy scenarios without net customer benefits are those assuming the lowest natural-gas prices when paired with either medium or zero CO_2 price assumptions. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefit is \$137 million.

Table 3. (Benefit)/Cost of New Wind and Transmission (2017-2050, $ million)

Price-Policy Scenario	**Extended PaR Stochastic-Mean PVRR(d)**
Low Gas, Zero CO_2	$174
Low Gas, Medium CO_2	$93
Low Gas, High CO_2	($194)
Medium Gas, Zero CO_2	($53)
Medium Gas, Medium CO_2	($137)
Medium Gas, High CO_2	($317)
High Gas, Zero CO_2	($341)
High Gas, Medium CO_2	($351)
High Gas, High CO_2	($595)

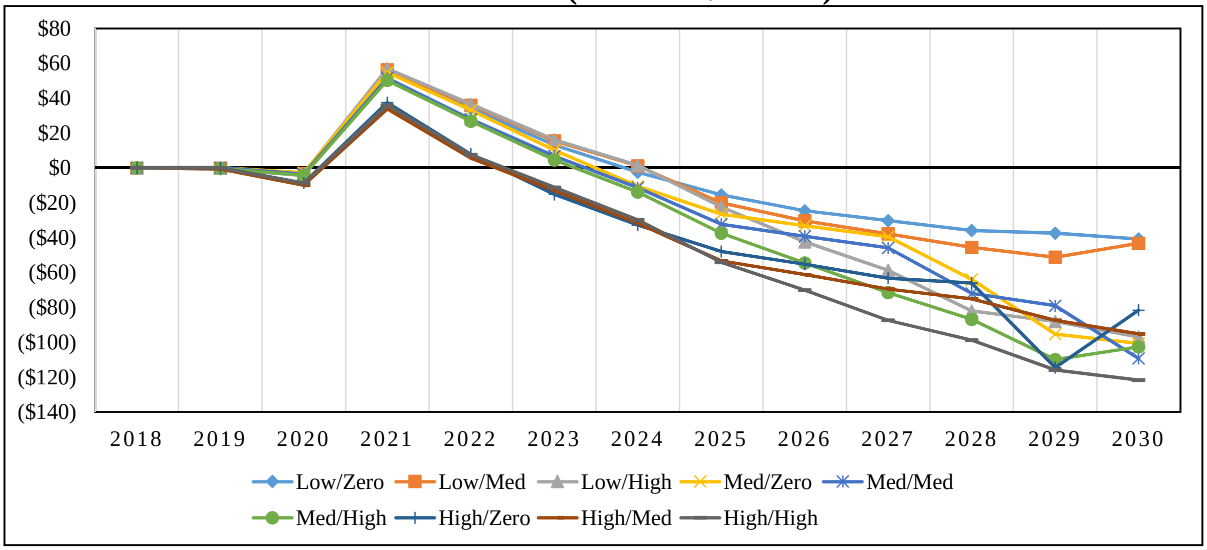
Q. What types of benefits will the new wind and transmission projects deliver?

A. PacifiCorp’s transmission system in eastern Wyoming is so constrained that no additional generation can be interconnected. Consequently, the new transmission enables interconnection of the new wind resources. The new transmission will relieve congestion, provide voltage support and improve reliability, enhance PacifiCorp's ability to comply with mandated reliability and performance standards, reduce line losses, and create potential for further increases to the transfer capability out of eastern Wyoming with construction of additional segments of the Energy Gateway transmission project. The economic benefits associated with the new wind, which includes reduced NPC and federal production tax credits ("PTCs"), offset the cost of the new transmission. Together, both projects can be completed with all-in economic savings for customers.

Q. Has PacifiCorp analyzed how the new wind and transmission projects are likely to affect revenue requirement over the near term?

A. Yes. As is the case with any investment having a relatively long life, there is more certainty in the projected benefits over the near term. In the case of the new wind resources, PTC benefits, which are not based on speculation, will provide significant customer benefits over the first 10 years of operation. Figure 1 shows that over the first 10 years, when PTC benefits will flow through to customers and as the assets begin to depreciate, the new wind and transmission projects provide annual revenue requirement benefits within three to four years of being placed in service across all nine price-policy scenarios presented in the Energy Vision 2020 Update.

Figure 1. (Reduction)/Increase in Annual Revenue Requirement with New Wind and Transmission (Nominal $ million)



Q. Will the presence or absence of these benefits impact the company's selection in the 2017R RFP, and ultimately impact the company's resource acquisition?

A. Yes. The IE will review and evaluate the resource(s) selected in the initial shortlist through the 2017R RFP. The IE will provide monthly status reports to the Commission, DPU and the company. The final shortlist will contain bids that the company, the IE, and the Commission will fully review to ensure that the projects will deliver least-cost, least-risk electricity to customers. As noted earlier, the company will only proceed with resource acquisitions if the benefits anticipated in the Energy Vision 2020 Update persist or improve through the 2017R RFP process.

Q. Please explain why the proposed RFP has been limited to Wyoming wind.

A. PacifiCorp uses the SO and PaR models to establish the least-cost, least-risk portfolio. The SO model is used to develop resource portfolios that meet planning-reserve margin targets and PaR is used to refine portfolio costs and assess portfolios risk. The SO model selects a portfolio of resources from a broad range of resource alternatives by minimizing the system present value revenue requirement ("PVRR"). The system

PVRR from the SO model reflects the cost of existing contracts, wholesale-market purchases and sales, the cost of new and existing generating resources (fuel, fixed and variable operations and maintenance, and emissions, as applicable), the cost of new demand-side management resources, and levelized revenue requirement of capital additions for existing resources and potential new generating resources. In developing the least-cost, least-risk portfolio of resources, the SO model optimizes the quantity, the type, and location of new resources over a 20-year time frame. In establishing a portfolio, the SO model has considered all available resource options, such as solar in Utah or wind in Oregon, and assessed their relative benefits (*i.e.*, capacity contribution and NPC value) against the resource costs (*i.e.*, capital costs, operations and maintenance costs, fuel costs, etc.).

All of the resource portfolios produced during the initial stages of the portfolio development phase of the 2017 IRP contained new Wyoming wind resources in 2021 and very few portfolios included wind resources outside of Wyoming in 2021.[4] None of the resource portfolios included other renewable resource technologies or other thermal generating resources in the 2017-2021 timeframe. Table 4 summarizes new generating resource selections in resource portfolios presented in the 2017 IRP that were not developed by forcing certain types of technologies or forcing near-term renewable resource acquisitions to specifically meet renewable portfolio standards in Oregon and Washington.[5] These findings clearly indicate that near-term procurement

[4] For modeling purposes, new wind resources in 2021 were used as a proxy on-line date for PTC-eligible wind achieving commercial operation by the end of 2020.
[5] The cases and data summarized Table 4 are based upon the case summaries and resource portfolios presented in Volume II, Appendix K of the 2017 IRP.

of Wyoming wind is most likely to deliver least-cost, least-risk electricity to Utah customers.

Table 4. Generating Resource Selections Before 2022 Included in 2017 IRP Resource Portfolios

Case	Wyoming Wind (MW)	Idaho Wind (MW)	Other Renewable (MW)	Thermal (MW)
REF	299	0	0	0
RH-1	300	0	0	0
RH-2	300	0	0	0
RH-3	235	0	0	0
RH-4	288	0	0	0
RH-5	229	0	0	0
RH-6	179	0	0	0
OP-1	229	0	0	0
OP-NT3	300	150	0	0
OP-REP	300	128	0	0
OP-GW4	1,200	0	0	0
RH2a	300	0	0	0
LD-1	300	0	0	0
LD-2	0	0	0	0
LD-3	300	0	0	0
PG-1	211	0	0	0
PG-2	300	0	0	0
CPP-C	300	0	0	0
CPP-D	9	0	0	0
FOT-1	300	0	0	0
CO_2-1	300	0	0	0
NO-CO_2	300	0	0	0
BP	300	150	0	0
GW-1	300	150	0	0
GW-2	300	150	0	0
GW-3	300	0	0	0
GW-4	1,200	0	0	0
Battery	1,100	0	0	0
CAES	1,100	0	0	0
FS-REP	300	103	0	0
FS-GW4 (Preferred Portfolio)	1,100	0	0	0
Total	**12,479**	**831**	**0**	**0**

In reviewing the new resources included in portfolios from the portfolio development phase of the 2017 IRP, it became clear that the amount of Wyoming wind included was limited by transmission constraints. The presence of the Wyoming wind resources across portfolios led the company to assess whether additional wind resources enabled by sub-segments of Energy Gateway West would further lower system costs. The company incorporated the Aeolus-to-Bridger/Anticline line as a specific sensitivity case in its broader Energy Gateway sensitivity analysis. The company's modeling of four Energy Gateway transmission sensitivities indicated there were potential benefits to including the Aeolus-to-Bridger/Anticline line in the portfolio.

While PacifiCorp analyzed a number of alternative resource portfolios in the 2017 IRP portfolio-development process, no other resource portfolio indicated that renewable resources delivered into other parts of the company's transmission system would provide economic benefits comparable to the benefits expected with the new wind and transmission projects included in the preferred portfolio. Capacity expansion modeling across the nine price-policy scenarios consistently selected Wyoming wind as a significant component of the optimal least-cost, least-risk portfolio.

Q. Did the company discuss including the Wyoming wind in the IRP pre-filing stakeholder process?

A. Yes. At the March 2017 public input meeting, the company presented this analysis and next steps to stakeholders, communicating the company's intention to further refine key assumptions for this sensitivity case. While the pre-filing stakeholder review process for the new wind and transmission projects was necessarily limited by the timing of the company's analysis, it was in customers' interest to consider these resources and ultimately include them in the 2017 IRP. The company explicitly chose to share the results of its analysis with stakeholders as they were being produced. Given the time-sensitivity of these resource opportunities, delaying the IRP to allow additional pre-filing review was not a viable option. Instead, the company expeditiously completed the necessary analysis and shared it with IRP stakeholders.

Q. Please explain why the company is not proposing an all-source RFP.

A. The company did not propose an all-source RFP for the following reasons:

(1) The 2017 IRP identified Wyoming wind as a time-limited opportunity for least-cost, least-risk resource(s);

(2) Results from the 2016R RFP—which produced competitive bids for over 6,000 MW of wind, solar, and geothermal projects under a range of commercial structures—confirmed that none of those proposals would deliver all-in economic benefits for customers; and,

(3) Broadening the scope of the 2017R RFP would create an untenable delay that would jeopardize the ability to capture the full value of PTCs to provide benefits to customers, and potentially undermine the viability of the 2017R RFP.

Q. Please describe how the 2017R RFP is fair and transparent and will facilitate robust market participation.

A. The company has tried to make the 2017R RFP as fair and transparent as possible. The IE and stakeholders had multiple opportunities, both in person and in writing, to provide feedback and recommendations on the 2017R RFP. The IE provided a thorough and comprehensive analysis of the filed 2017R RFP in its August 11, 2017 report, and parties provided detailed written comments on August 7, 2017, and again on August 18, 2017. This review and analysis, and the separate review and comments by the Oregon IE and stakeholders, led the company to make numerous changes to the 2017R RFP. The 2017R RFP, as revised, will encourage and produce substantial market response.

Specifically, the Company made the following changes that will enhance and encourage market participation:

- Revised the system impact study ("SIS") requirement to require the bidder to demonstrate that it has initiated the study phase of the interconnection process (*i.e.*, signed agreement and paid deposit to begin feasibility study), and added a condition requiring a SIS by the initial shortlist to confirm costs and interconnection consistent with the December 31, 2020 commercial operation date ("COD"). This change will allow bidders more time to comply with the requirement, while still providing the information required to fairly evaluate bids.

- Modified the PTC requirement to allow bidders to deliver projects that qualify for less than 100 percent of the federal PTCs, while maintaining the December 31, 2020 COD deadline. This change expands the range of projects that can compete in the 2017R RFP.

- Added clarifying language to the 2017R RFP in Section 4.B and 4.C to emphasize that PPAs and BTAs are negotiated agreements meant to address risk on both sides of the transaction with the ability to redline and modify the terms and conditions in the pro forma documents. This change will allow bidders to negotiate PPA or BTA terms that they may otherwise consider to be deal-breakers, which will encourage broader participation in the 2017R RFP.

- Expanded the 2017R RFP resource-type eligibility to include both new and repowered existing wind resources because both are considered eligible for PTC benefits under IRS guidelines. But bids submitted with repowered wind resources will not be allowed if the existing wind resource currently has a PPA with the company for the offtake of the energy. This change will promote diversity in the Wyoming wind projects that may compete in the 2017R RFP.

- Changed the 2017R RFP provision in Section 3.G that a base bid and one alternative can be submitted for the $10,000 bid fee to instead allow for the base bid and two alternatives without additional fees. This change will allow enhanced participation by allowing bidders more opportunities to bid for the same base bid fee.

- Added credit requirements to the RFP to allow bidders to reflect the credit requirements in their bids and evaluate how requirements may affect their decision to compete. The company also expanded the use of contract terms and milestones to manage down the security for early achievement of the commercial operation date. This change will allow bidders to make a more informed decision whether to compete.

- Expanded contract terms for PPA bidders to provide an equivalent evaluation life between a PPA and BTA, allowing PPA bidders to offer a 20-year contract with up to a 10-year extension at a firm price that can be exercised at the company at the end of the 20-year term. This change puts the PPA bid term on equal footing with the BTA asset life and will promote participation by PPA bidders.

Q. What level of market participation does the company anticipate for the 2017R RFP?

A. Thousands of megawatts of Wyoming wind resource capacity are currently seeking interconnection service from PacifiCorp's transmission function, suggesting adequate and increasing wind development activity in Wyoming to support a robust response to the 2017R RFP. To date, many different project developers have participated in the 2017R RFP bidder workshops and several of these developers have communicated an intent to participate in the 2017R RFP. In addition, at the August 29, 2017 special public meeting where the Oregon Commission conditionally approved the 2017R RFP, the Northwest and Intermountain Power Producers Coalition and Renewable Northwest (organizations whose membership include developers) both stated that their members have indicated a strong desire to participate in the 2017R RFP. The company expects that the revisions to the 2017R RFP, described above, may further enhance participation.

Q. Aside from the reasons you've stated above, why does the company believe that an expansion of the 2017R RFP to an all-source RFP is not necessary or in customers' best interests?

A. The company recently tested the market in 2016 when it issued the 2016R RFP for renewable resources, which did not result in any resource acquisition. The results from the 2016R RFP, which resulted in over 6,000 MW in bids, confirmed that none of the proposals offered would provide all-in economic benefits to customers, and the company ultimately closed the 2016R RFP without executing any agreements to procure new resources. In addition, both renewable and non-renewable resource costs and benefits have been fully vetted in the 2017 IRP modeling, which demonstrates that a broadened geographic scope or technology scope would not be reasonably expected to deliver least-cost, least-risk electricity to Utah customers.

Q. Is the company considering initiating other RFPs in the near future to test the market?

A. Not at this time. As discussed above, the company's 2017R RFP is limited to the Wyoming wind resources that were identified in the preferred portfolio in the 2017 IRP. Given the IRP results, as well as the outcome of the 2016R RFP, the company is not planning to initiate a broader renewable resource RFP. But if the Commission and stakeholders prefer to test the market and assess a broader scope for potential renewable resource procurement opportunities, a separate RFP process that casts a wider net for resources across the company's system to seek other opportunities that provide an all-in economic benefit to customers can be initiated. This solicitation process could be initiated in early 2018, and the appropriateness of a second, broader RFP could be vetted through the on-going review of the 2017 IRP. If additional renewable resources identified through a second solicitation process provide all-in economic benefits for customers, those opportunities can be pursued in addition to, not instead of, the wind resource procurement proposed in the 2017R RFP, and the approach of initiating a second RFP would not jeopardize acquisition of least-cost, least-risk resources through the 2017R RFP.

Q. Does approval of the 2017R RFP prejudge the outcome of the 2017 IRP or prudence of the resource acquisition?

A. No. While the Commission expressed concern that the resource selection had not yet been thoroughly reviewed in the 2017 IRP proceeding in Docket No. 17-035-16,[6] that proceeding is on-going and the Commission's decision regarding the 2017R RFP will not prejudge the outcome. In addition, the significant energy resource decision proceeding is on-going in Docket No. 17-035-40. These two proceedings, though filed concurrently with the 2017R RFP proceeding, are progressing on their own independent schedules. Approval of the 2017R RFP is just one step in the regulatory review process, and will not be the Commission's final opportunity to weigh in on the acquisition of Wyoming wind resources. My understanding is that the Commission has recognized that the resource solicitation and acquisition decision approval processes are separate from the IRP acknowledgment process.[7]

Q. What is the significance of the Commission's approval of the 2017R RFP?

A. The Commission's approval will allow the company to issue the 2017R RFP with oversight from an IE that has been approved by the Commission. If the Commission approves the 2017R RFP, several additional steps are needed before any resource acquisition is made, and the timing of a decision to acquire resources will occur after the Commission has the opportunity to conclude its consideration of the 2017 IRP.

[6] Order at 2.
[7] *See, e.g. In the Matter of PacifiCorp's 2006 Integrated Resource Plan*, Docket No. 07-2035-01, Report and Order at 5-6 (Feb. 6, 2008).

Still more steps must occur before the company can seek a prudence determination and recovery of the costs of the resources in rates. For all of these additional steps, there will be ample opportunity for stakeholders and the Commission to thoroughly review and analyze the company’s investment decisions.

Q. Does this conclude your supplemental testimony?

A. Yes.

Rocky Mountain Power
Exhibit RMP___(RTL-S1)
Docket No. 17-035-23
Witness: Rick T. Link

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

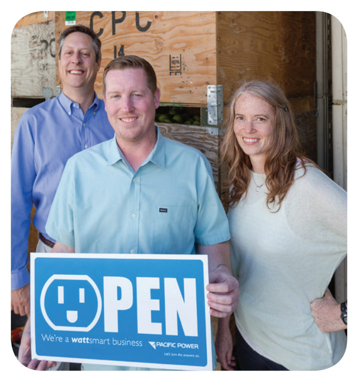
Exhibit Accompanying Supplemental Testimony of Rick T. Link
Energy Vision 2020 Update

August 2017

2017 INTEGRATED RESOURCE PLAN

Energy Vision 2020 Update

August 2, 2017



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SECTION 1– INTRODUCTION

In this informational filing, PacifiCorp presents an updated economic analysis supporting the wind repowering, new transmission, and new wind investments (collectively, the Energy Vision 2020 projects) identified in the 2017 IRP and the associated action plan, specifically action items 1a, 1b, and 2a. This updated economic analysis was developed to support a series of concurrent regulatory filings made with the Wyoming Public Service Commission (WPSC), the Utah Public Service Commission (UPSC), and the Idaho Public Utilities Commission (IPUC) on June 30, 2017. The updated economic analysis was prepared to ensure these filings were supported using the most currently available information and is being provided to IRP stakeholders so that all parties have access to the same analysis as they move forward with their on-going review of PacifiCorp's 2017 IRP. In making this informational filing, PacifiCorp has not modified its 2017 IRP preferred portfolio or action plan in any way.

Since filing its 2017 IRP on April 4, 2017, and consistent with the 2017 IRP action plan, PacifiCorp filed applications for certificates of public convenience and necessity (CPCNs) with the WPSC on June 30, 2017. These CPCN applications are required for the new wind and new transmission investments outlined in action items 1a and 2a of the 2017 IRP action plan. PacifiCorp also filed an application with the WPSC on June 30, 2017, seeking approval of its proposed ratemaking treatment for the wind repowering project. Concurrent with these filings, PacifiCorp filed separate applications for Energy Vision 2020 projects, seeking approval of its proposed ratemaking treatment with the UPSC and the IPUC. There are existing rate-recovery mechanisms in Oregon and Washington for investments in renewable resources that provide a path for cost recovery closer in time to project completion. In California, PacifiCorp is required to file a general rate case in 2019, which may include the costs and benefits of Energy Vision 2020 investments; alternatively, California's Post-Test Year Adjustment Mechanism may be used to recover costs after the 2019 general rate case.

Wind Repowering Overview

Wind repowering takes advantage of technological advancements that allow greater generation from existing wind resources. Wind repowering involves installation of new rotors with longer blades and new nacelles with higher-capacity generators. These plant upgrades significantly increase energy output without changing the footprint, towers, and foundations of the wind facilities. Longer blades allow wind turbines to produce more energy over a wider range of wind speeds. The nacelle is the housing that sits atop the tower and contains the gear box, low- and high-speed shafts, generator, controller, and brake. The new nacelles will include sophisticated control systems and more robust components necessary to handle greater loads that come with longer blades.

Together, the new rotor and nacelles are estimated to increase generation from the repowered turbines by 13 to 35 percent, resulting in an overall average increase in generation of 19 percent (or 21 percent if new interconnection agreements are executed).

On December 18, 2015, Congress enacted changes to the federal Internal Revenue Code that extended the full value of production tax credits (PTCs) for wind energy facilities that began construction in 2015 and 2016. The Internal Revenue Service (IRS) has issued guidance that establishes "safe harbor" for taxpayers to demonstrate the year a facility will be deemed to "begin construction," thereby setting the value of the PTC.

Repowering PacifiCorp's wind fleet now will allow the resources to requalify for PTCs, which will expire 10 years from the original commercial operation date of the resource (expiration dates range from 2016 through 2020). To maximize the PTC benefit, in December 2016, PacifiCorp contracted with General Electric, Inc., and Vestas-American Wind Technology, Inc., for the purchase of new wind-turbine generator equipment. These safe-harbor equipment purchases allow the repowered facilities to qualify for 100 percent of available PTC benefits if they are commercially operational within four calendar years—or by the end of 2020. PacifiCorp's purchases last year were important because wind facilities that begin construction after 2016 and come online after 2020 will receive a 20 percent decrease in the tax benefits that can be passed on to customers each year. Thus, a delay in acquiring safe-harbor equipment would have made the economics of repowering less attractive and deprived customers of the substantial benefits that can be achieved if repowering is completed by the end of 2020.

To meet the 2020 deadline, PacifiCorp plans to order the necessary equipment and execute the necessary contracts in early 2018 and complete much of the construction in 2019. The renewal of the PTC has dramatically increased the demand for materials, equipment, and labor for wind facilities. By completing the majority of the construction in 2019, PacifiCorp will mitigate the risk of construction delays, or delays associated with the procurement of equipment, and allow sufficient time to meet the 2020 deadline.

In addition, completing the majority of construction in 2019 will maximize the value of the existing PTCs, while minimizing the period between the expiration of the prior PTCs and the eligibility for new PTCs. By achieving commercial operation in 2019 for most of the facilities (Dunlap will be completed in 2020), PacifiCorp will also minimize the time during which the wind facilities are ineligible for PTCs.

The customer benefits resulting from wind repowering derive in part from the fact that repowering allows PacifiCorp's existing wind resources to requalify for PTCs—which are then passed through to customers. Customer benefits are expected to exceed the cost of wind repowering and save customers money. Wind repowering creates benefits by:

- Increasing energy production from wind facilities by 11 to 35 percent because of longer blades and higher-capacity generators;
- Reducing ongoing operating costs associated with aging wind turbines;
- Extending the useful lives of the wind facilities by at least 10 years;
- Reducing customer costs by requalifying the wind projects for PTCs for an additional 10 years; and
- Improving the ability of wind facilities to deliver cost-effective, renewable energy into the transmission system through enhanced voltage support and power quality.

PacifiCorp's updated economic analysis of the wind repowering project demonstrates that it will provide substantial customer benefits. As described in more detail in Sections 2 and 3 of this informational update, PacifiCorp analyzed nine different scenarios, each with varying natural gas and carbon dioxide (CO_2) price assumptions, and all nine scenarios show customer benefits ranging from $41 million when assuming low natural gas and zero CO_2 prices to $589 million when assuming high natural gas and high CO_2 prices. With medium natural gas price and CO_2 price assumptions, wind repowering results in customer benefits of $359 million.

New Wind and Transmission Overview

The new wind and transmission projects in the 2017 IRP preferred portfolio are central to PacifiCorp's current plans to use opportunities presented by the extension of the federal PTC to make major investments that provide significant savings to customers over the lives of the resources. The new wind and transmission projects are mutually dependent on one another. The new wind resources rely on the new transmission for interconnection into PacifiCorp's transmission system. In turn, the new transmission is supported by key economic attributes of the new wind: zero-fuel-cost generation that lowers net power costs (NPC) and provides ten years of PTCs. The new wind will also generate renewable energy credits (RECs), which can be sold in the market and lower net customer costs or otherwise be used to meet state renewable resource procurement targets. The new wind resources help decarbonize PacifiCorp's resource portfolio, mitigating long-term risk associated with potential future state and federal policies targeting CO_2 emissions reductions from the electric sector.

The new transmission also provides significant benefits to customers. The Aeolus-to-Bridger/Anticline transmission line is a sub-segment of PacifiCorp's Energy Gateway West transmission project, and is an integral component of the long-term transmission plan for the region. PacifiCorp, with stakeholder involvement, has pursued permitting of the Energy Gateway West transmission project since 2008. The new transmission will relieve congestion on the current transmission system in eastern Wyoming, provide voltage support to the Wyoming transmission network, improve overall reliability of the transmission system, enhance PacifiCorp's ability to comply with mandated reliability and performance standards, reduce line losses, and create the potential for further increases to the transfer capability across the Aeolus-to-Bridger/Anticline transmission line with the construction of additional segments of the Energy Gateway project.

Timing is critical for both the new wind and transmission projects. These assets must achieve commercial operation by the end of 2020 to qualify for the full benefits of the PTCs and maintain favorable economics. Thus, PacifiCorp must move quickly, particularly on the new transmission, which will take several years to fully permit, obtain the necessary rights-of-way, and construct. To complete construction of the new wind and transmission by December 31, 2020, PacifiCorp has requested expedited review of its CPCN applications.

Because of the time-sensitivity of the new wind and transmission projects, PacifiCorp is conducting its 2017R request for proposals (RFP) process simultaneously with its CPCN applications and on-going review of these investments by parties participating in PacifiCorp's 2017 IRP process. Although unusual, this approach is necessary in this case. If PacifiCorp waited until the conclusion of the 2017R RFP to seek CPCNs, or similarly, waited for conclusion of review of PacifiCorp's 2017 IRP to issue its 2017R RFP, the new wind and transmission projects could not be completed by the end of 2020, and customers would lose significant PTC benefits. To allow the new wind and transmission projects to move forward, PacifiCorp has pursued specific wind projects that will be benchmark resources in the 2017R RFP. These resources include three

250 MW facilities (referred to as Ekola Flats, TB Flats I, and TB Flats II) and a fourth 110 MW facility (McFadden Ridge II), all located in Wyoming. These proxy resources, in addition to 320 MW of qualifying facility (QF) resources enabled by the new transmission investment, are included in the updated economic analysis of the new wind and transmission projects.

PacifiCorp will update its economic analysis to reflect the specific resources selected to the 2017R RFP final shortlist, which the company plans to establish in early January 2018. If other resources are ultimately selected through the 2017R RFP, they will be equal to or better than the wind projects assumed in PacifiCorp's updated economic analysis.

The new transmission investment includes six major elements: (1) the 140-mile, Aeolus-to-Anticline 500 kV line, which includes construction of the new Aeolus and Anticline substations; (2) the five-mile Anticline to Jim Bridger 345 kV line, which includes modifications at the existing Jim Bridger substation to allow termination of the 345 kV line; (3) installation of a voltage control device at the Latham substation; (4) a new 16-mile 230 kV transmission line parallel to an existing 230 kV line from the Shirley Basin substation to the proposed Aeolus substation, including modifications to the existing Shirley Basin substation; (5) the reconstruction of four miles of an existing 230 kV line between the proposed Aeolus substation and the Freezeout substation, including modification as required at the Freezeout substation; and (6) the reconstruction of 14 miles of an existing 230 kV transmission line between the Freezeout substation and the Standpipe substation, including modifications as required at the Freezeout and Standpipe substations.

The benefits of the transmission project fall into three broad categories. First, the new transmission project will relieve congestion in eastern Wyoming, which will allow greater resource interconnection in that part of the state. PacifiCorp's current transmission system in eastern Wyoming is operating at capacity, which limits transfer of existing resources from eastern Wyoming and precludes the ability to interconnect additional resources east of the proposed Aeolus-to-Bridger/Anticline line. The new transmission will increase the transfer capability from east to west by 750 MW. When the new transmission project is complete, they it will allow interconnection of up to 1,270 MW of incremental wind resources.

Second, the new transmission will provide critical voltage support to the transmission system in southeastern Wyoming. Under certain operating conditions, voltage control issues have limited the ability to add additional resources, particularly wind resources. The addition of the new transmission will solve the voltage control issues.

Third, the transmission projects will also increase reliability, reduce capacity and energy losses on the transmission system, and provide greater flexibility to manage existing generation resources. Currently, outages on the existing 230 kV system in eastern Wyoming result in deration of the transfer capacity in the area and some outage scenarios require significant generation curtailment. The new 500 kV transmission segment will significantly reduce, if not eliminate, many of the impacts caused by the 230 kV outages.

PacifiCorp's updated economic analysis of the new wind and transmission projects demonstrates that these investments will provide substantial customer benefits. As described in more detail in Section 4 of this informational update, when using medium natural gas and CO_2 price assumptions, PacifiCorp's updated economic analysis shows a present-value reduction in revenue requirement due to the new wind and transmission projects of $137 million.

SECTION 2 – METHODOLOGY

System Modeling Methodology

In updating and refining its analytics for the Energy Vision 2020 projects, PacifiCorp relied upon the same modeling tools used to develop and analyze resource portfolios in its 2017 IRP. These modeling tools calculate system present value revenue requirement (PVRR) by identifying least-cost resource portfolios and dispatching system resources over a 20-year forecast period (2017–2036). Net customer benefits are calculated as the present-value revenue requirement differential (PVRR(d)) between two simulations of PacifiCorp's system. One simulation includes the relevant components of the Energy Vision 2020 projects (*i.e.*, either wind repowering or new wind and new transmission) and the other simulation excludes these investments. Customers are expected to realize benefits when the system PVRR with the Energy Vision 2020 projects is lower than the system PVRR without these investments. Conversely, customers would experience increased costs if the system PVRR with Energy Vision 2020 projects were higher than the system PVRR without them.

Models

PacifiCorp used the System Optimizer (SO) model and the Planning and Risk model (PaR) to develop resource portfolios and to forecast dispatch of system resources in simulations with and without the Energy Vision 2020 projects.

The SO model is used to develop resource portfolios with sufficient capacity to achieve a target planning-reserve margin. The SO model selects a portfolio of resources from a broad range of resource alternatives by minimizing the system PVRR. In selecting the least-cost resource portfolio for a given set of input assumptions, the SO model performs time-of-day, least-cost dispatch for existing resources and prospective resource alternatives, while considering the cost-and-performance characteristics of existing contracts and prospective demand-side-management (DSM) resources—all within or connected to PacifiCorp's system. The system PVRR from the SO model reflects the cost of existing contracts, wholesale-market purchases and sales, the cost of new and existing generating resources (fuel, fixed and variable operations and maintenance, and emissions, as applicable), the cost of new DSM resources, and levelized revenue requirement of capital additions for existing coal resources and potential new generating resources.

PaR is used to develop a chronological unit commitment and dispatch forecast of the resource portfolio generated by the SO model, accounting for operating reserves, volatility and uncertainty in key system variables. PaR captures volatility and uncertainty in its unit commitment and dispatch forecast by using Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. PaR uses the same common input assumptions that are used in the SO model, with resource-portfolio data provided by the SO model results. The PVRR from PaR reflects a distribution of system variable costs, including variable costs associated with existing contracts, wholesale-market purchases and sales, fuel costs, variable operations and maintenance costs, emissions costs, as applicable, and costs associated with energy or reserve deficiencies. Fixed costs that do not change with system dispatch, including the cost of DSM resources, fixed operations and maintenance costs, and the levelized revenue requirement of capital additions for existing coal resources and potential new generating resources, are based on the fixed costs from the SO model, which are combined with the distribution of PaR variable costs to establish a distribution of system PVRR for each simulation.

PacifiCorp uses the SO model and PaR to produce and evaluate resource portfolios in its IRP. PacifiCorp also uses these models to analyze resource-acquisition opportunities, resource retirements, resource capital investments, and system transmission projects. The models were used to support the successful acquisition of the Chehalis combined-cycle plant, to support selection of the Lake Side 2 combined-cycle resource through an RFP process, and to evaluate installation of emissions control equipment. These models will also be used to evaluate bids in the soon-to-be-issued 2017R RFP, which is being issued to solicit bids for new wind resources.

The SO model and PaR are the appropriate modeling tools when evaluating significant capital investments that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The SO model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource capital projects and is needed to understand how the type, timing, and location of future resources might be affected by Energy Vision 2020 projects. PaR provides additional granularity on how Energy Vision 2020 projects are forecasted to affect system operations, recognizing that key system conditions are volatile and uncertain. Together, the SO model and PaR are best suited to perform a net-benefit analysis for Energy Vision 2020 projects that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP.

Just as it evaluates resource-portfolio alternatives in the IRP, PacifiCorp uses the stochastic-mean PVRR and risk-adjusted PVRR, calculated from PaR study results, to assess the stochastic system cost risk of its proposed Energy Vision 2020 projects. With Monte Carlo sampling of stochastic variables, PaR produces a distribution of system variable costs. The stochastic-mean PVRR is the average of net variable operating costs from the distribution of system variable costs, combined with system fixed costs from the SO model. PacifiCorp uses a risk-adjusted PVRR to evaluate stochastic system cost risk. The risk-adjusted PVRR incorporates the expected value of low-probability, high-cost outcomes. The risk-adjusted PVRR is calculated by adding five percent of system variable costs, from the 95th percentile of the distribution of system variable costs, to the stochastic-mean PVRR.

When applied to its updated economic analysis, the stochastic-mean PVRR represents the expected level of system costs from cases with and without Energy Vision 2020 projects. The risk-adjusted PVRR is used to assess whether Energy Vision 2020 projects cause a disproportionate increase to system variable costs under low-probability, high-cost system conditions.

Price-Policy Scenarios

In addition to assessing stochastic system cost risk, PacifiCorp analyzed the wind repowering project under a range of assumptions regarding wholesale market prices and CO_2 policy (price-policy) assumptions. These assumptions drive benefits associated with NPC, and so it is important to understand how the net-benefit analysis is affected under a range of potential outcomes. Each pair of model simulations—with and without the relevant components of the Energy Vision 2020 projects, in both the SO model and PaR—was analyzed under varying combinations of these price-policy assumptions.

Wholesale-power prices, often set by natural gas prices, and the system cost impacts of potential CO_2 policies influence the forecast of net system benefits from the Energy Vision 2020 projects. Wholesale-power prices and CO_2 policy outcomes affect the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect NPC benefits, non-NPC variable cost benefits, and system fixed-cost benefits of the Energy Vision 2020 projects. Because wholesale-power prices and CO_2 policy outcomes are both uncertain and important drivers to the updated economic analysis, PacifiCorp studied the economics of the Energy Vision 2020 projects under a range of different price-policy scenarios.

Considering that there is a high level of correlation between wholesale-power prices and natural gas prices, the wholesale-power price scenarios were based on a range of natural gas price assumptions. This ensures consistency between power price and natural gas price assumptions for each scenario. PacifiCorp implemented its CO_2 policy assumptions through a CO_2 price, expressed in dollars-per-ton.

Since filing the 2017 IRP, it has become increasingly unlikely that the CPP will be implemented in its current form. However, it is possible that future CO_2 policies targeting electric-sector emissions could be adopted and impose incremental costs to drive emissions reductions. CO_2 price assumptions used in the price-policy scenarios are not intended to mimic a specific type of policy mechanism (*i.e.*, a tax or an allowance price under a cap-and-trade program), but are intended to recognize that there might be future CO_2 policies that impose a cost to reduce emissions. Table 2.1 summarizes the nine price-policy scenarios used to analyze the Energy Vision 2020 projects.

Table 2.1 – Price-Policy Scenarios

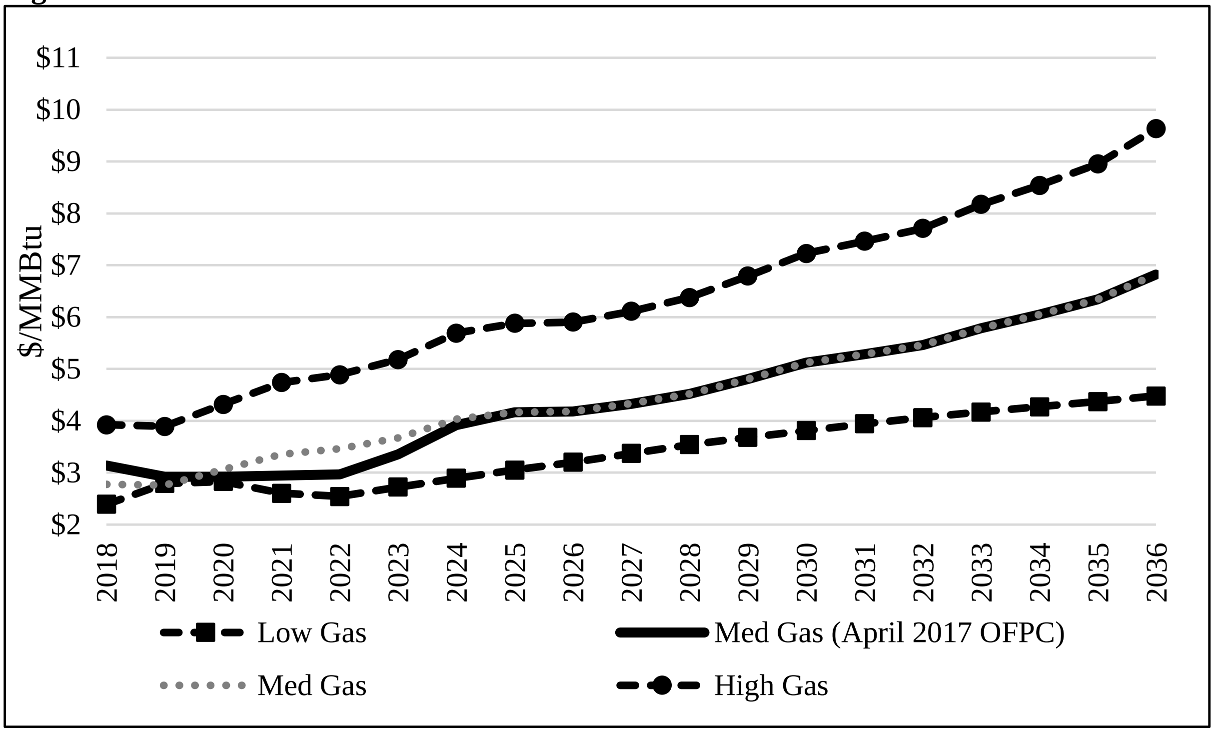
Price-Policy Scenario	Natural Gas Prices (Levelized $/MMBtu)*	CO_2 Price Description
Low Gas, Zero CO_2	$3.19	$0/ton
Low Gas, Medium CO_2	$3.19	$3.41/ton in 2025 growing to $14.40/ton in 2036
Low Gas, High CO_2	$3.19	$4.73/ton in 2025 growing to $38.42/ton in 2036
Medium Gas, Zero CO_2	$4.07	$0/ton
Medium Gas, Medium CO_2	$4.13	$3.41/ton in 2025 growing to $14.40/ton in 2036
Medium Gas, High CO_2	$4.13	$4.73/ton in 2025 growing to $38.42/ton in 2036
High Gas, Zero CO_2	$5.83	$0/ton
High Gas, Medium CO_2	$5.83	$3.41/ton in 2025 growing to $14.40/ton in 2036
High Gas, High CO_2	$5.83	$4.73/ton in 2025 growing to $38.42/ton in 2036

The medium-natural-gas-price assumptions that are paired with zero CO_2 prices reflect natural-gas prices from PacifiCorp's official forward price curve (OFPC) dated April 26, 2017. The OFPC uses observed forward market prices as of April 26, 2017, for 72 months, followed by a 12-month transition to natural-gas prices based on a forecast developed by an independent third party. The low-, medium-, and high-natural-gas price assumptions used for all other scenarios were chosen after reviewing a range of credible third-party forecasts. Attachment A to this informational filing shows the range in natural-gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios to evaluate the Energy Vision 2020 projects.

The low-natural-gas price assumption was derived from a low-price scenario developed by an independent third party, which is based on surging growth in price-inelastic associated gas, technology improvements, stagnant liquefied-natural-gas exports, and an ever-expanding resource base. The medium-natural-gas price assumption, which is used beyond month 84 in the April 2017 OFPC, and in all months when medium-natural-gas prices are paired with medium or low CO_2 price assumptions, is based on a base-case forecast from another independent third party that is reasonably aligned with other base-case forecasts. The high-natural-gas price assumption was based on a high-price scenario from this same forecaster. The high-price scenario is based on risk-aversion, whereby natural-gas developers are reluctant to commit capital before demand, and the associated price response, materializes. This gives rise to exaggerated boom-bust cycles (cyclical periods of high prices and low prices). PacifiCorp smoothed the boom-bust cycle in the third party's high-price scenario because the specific timing of these cycles are extremely difficult to project with reasonable accuracy.

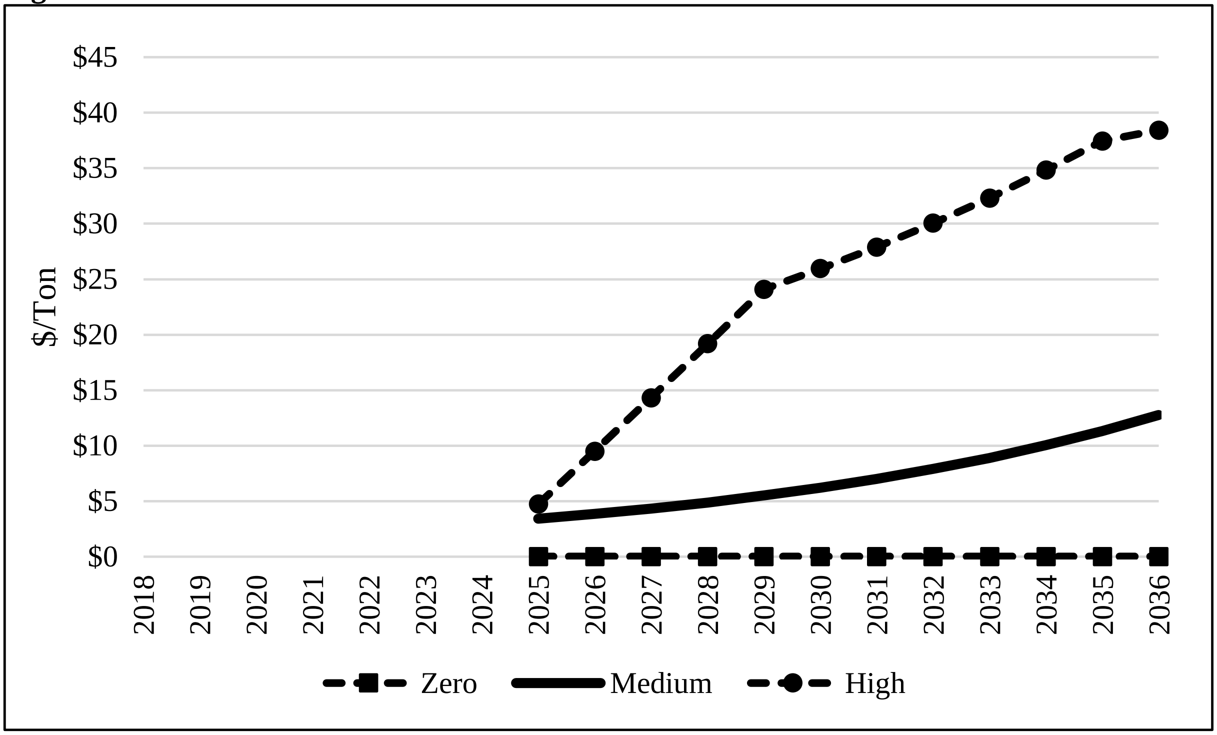
Figure 2.1 shows Henry Hub natural-gas price assumptions from the April 2017 OFPC, low-, medium-, and high-natural-gas price scenarios. The April 2017 OFPC forecast only differs from the medium-natural-gas-price assumption in that it reflects observed-market forwards through the first 72 months followed by a twelve-month transition to an independent third-party's base-case forecast.

Figure 2.1 -- Nominal Natural-Gas Price Scenarios



As with natural-gas prices, the medium- and high-CO_2 price assumptions are based on independent third-party projections assuming CO_2 prices start in 2025. To bracket the low end of potential policy outcomes, PacifiCorp assumes there are no future policies adopted that would require incremental costs to achieve emissions reductions in the electric sector. In this scenario, the assumed CO_2 price is zero. Figure 2.2 shows the three CO_2 price assumptions used to analyze the Energy Vision 2020 projects.

Figure 2.2 -- Nominal CO_2-Price Scenarios



Annual Revenue Requirement Modeling Methodology

The system PVRR from the SO model and PaR is calculated from an annual stream of forecasted revenue requirement over a 20-year time frame, consistent with the planning period in the IRP. The annual stream of forecasted revenue requirement captures nominal revenue requirement for non-capital items (*e.g.*, NPC, fixed operations and maintenance) and levelized revenue requirement for capital expenditures. To estimate the annual revenue requirement impacts of the Energy Vision 2020 projects, project capital costs need to be considered in nominal terms (*i.e.*, not levelized).

Levelization of capital revenue requirement is necessary in these models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. Without levelization, this potential distortion is driven by how capital costs are included in rate base over time. Capital revenue requirement is generally highest in the first year an asset is placed in service and declines over time as the asset depreciates.

Consider the potential implications of modeling nominal capital revenue requirement for a future generating resource needed in 2036, the last year of the 2017 IRP planning period. If nominal capital revenue requirement were assumed, the model would capture in its economic assessment of resource alternatives the highest, first-year revenue requirement capital cost without having any foresight on the potential benefits that resource would provide beyond 2036. If nominal capital costs were applied, the model's economic assessment of resource alternatives for the 2036 resource need would inappropriately favor less capital-intensive projects or projects having longer asset lives, even if those alternatives would increase system costs over their remaining life. Levelized capital costs for assets that have different lives and in-service dates is an established way to address these types of distortions in the comparative economic analysis of resource alternatives.

In the model simulations that exclude Energy Vision 2020 projects, the annual stream of costs for wind facilities that are within the wind repowering scope, including levelized capital, are removed from the annual stream of costs used to calculate the stochastic-mean system PVRR. Similarly, in the simulation that includes Energy Vision 2020 projects, the annual stream of costs for repowered wind facilities and new wind facilities, including levelized capital and PTCs, and costs associated with the new transmission project are temporarily removed from the annual stream of costs used to calculate the stochastic-mean PVRR. The differential in the remaining stream of annual costs, which includes all system costs except for those associated with the Energy Vision 2020 projects, represents the net system benefit caused by the Energy Vision 2020 projects.

These data are disaggregated to isolate the estimated annual NPC benefits, other non-NPC variable-cost benefits (i.e., variable operations and maintenance and emissions costs for those scenarios that include a CO_2 price assumption), and fixed-cost benefits. To complete the annual revenue requirement forecast, the change in fixed costs for Energy Vision 2020 projects, including nominal capital revenue requirement and PTCs, are added back in with the annual system net benefits caused by these investments.

Extension of Net Benefits Through 2050

The change in annual revenue requirement is estimated through 2050. This captures the full 30-year life of the new equipment installed on repowered wind facilities and the full 30-year life of new wind resources that are part of the Energy Vision 2020 projects.

The PaR forecast period runs from 2017 through 2036. The change in net system benefits caused by Energy Vision 2020 projects over the 2028 through 2036 time frame, expressed in dollars-per-MWh of incremental energy output from repowered and new wind facilities, were used to estimate the change in system net benefits from 2037 through 2050. This calculation was performed in several steps.

First, the net system benefits caused by Energy Vision 2020 projects were divided by the change in incremental energy expected from repowered and new wind facilities, as modeled in PaR over the 2028-through-2036 time frame. Next, the net system benefits per MWh of incremental energy from the repowered and new wind projects over the 2028-through-2036 time frame were levelized. These levelized results were extended out through 2050 at inflation. The levelized net system benefits per MWh of incremental energy output from the repowered and new wind projects over the 2037-through-2050 time frame were then multiplied by the change in incremental energy output from repowered and new wind projects over the same period.

Consistent with the 2017 IRP, PacifiCorp's updated economic analysis assumes the Dave Johnston coal plant, located in eastern Wyoming, retires at the end of 2027. When this plant is assumed to retire, transmission congestion affecting energy output from resources in eastern Wyoming, where many repowered wind resources are located and all of the new wind resources are located, is reduced. The incremental energy output from repowered and new wind resources provides more system benefits when not constrained by transmission limitations. Consequently, the net system benefits caused by repowered and new wind over the 2028-through-2036 time frame, after Dave Johnston is assumed to retire, is representative of net system benefits that could be expected beyond 2036.

Assumptions

Energy Vision 2020 Cost and Performance

Beyond the price-policy assumptions used to analyze a range of NPC-related benefits, the updated economic analysis reflects updated assumptions for up-front capital costs, run-rate operating costs, and energy output associated with Energy Vision 2020 projects. Table 2.2 summarizes updated cost and performance assumptions for Energy Vision 2020 projects. Additional detail is included in the confidential work papers supporting this informational filing.

Table 2.2 – Updated Cost and Performance Assumptions for Energy Vision 2020 Projects

	2017 IRP	Updated Analysis
In-Service Capital Cost	$3.54 billion	$3.21 billion
In-Service Incremental Annual Energy	4,431 GWh	4,823 GWh
Existing Wind Capacity in Repowering Scope	905 MW	999 MW
New Wyoming Wind Capacity	1,100 MW	1,180 MW
Transmission Transfer Capacity	750 MW	750 MW

Consistent with action item 1a in the 2017 IRP action plan and as discussed further in Section 3 below, PacifiCorp's updated economic analysis includes an assessment of the scope of the wind repowering project. Based on this assessment, the scope of the wind repowering project has been expanded to include the 94 MW Goodnoe Hills wind facility located in Washington.

PacifiCorp also updated its assumptions for new wind resource capacity to reflect specific wind projects, which includes 860 MW of wind resource capacity that the company will offer as benchmark resources in the 2017R RFP and 320 MW from certain QF wind projects that are located in the Aeolus area, have executed power purchase agreements (PPAs) with PacifiCorp, and have preferential positions in the transmission interconnection queue. These QF projects are reasonably expected to interconnect to PacifiCorp's transmission system after the new transmission project is placed in service and are assumed to achieve commercial operation at the end of 2021, consistent with the terms in their PPAs. Because these QF projects are not expected to be able to interconnect with PacifiCorp's transmission system without the new transmission investments, they are only included in SO model and PaR simulations that include Energy Vision 2020 projects.

Consistent with the assumptions used in the 2017 IRP, PacifiCorp's updated economic analysis continues to assume that the up-front capital costs for the new transmission will contribute to retail-customer rate base and that the revenue requirement for these investments will be partially offset by incremental revenue from other transmission customers. The up-front transmission cost will flow into PacifiCorp's formula transmission rate under its Open Access Transmission Tariff (OATT) and generate revenue credits that offset costs for retail customers.

PacifiCorp's merchant function, which uses PacifiCorp's transmission system to serve retail-customer load and manage retail-customer NPC through off-system market sales and purchases, is the largest user of PacifiCorp's transmission system. However, other transmission customers pay OATT-based transmission rates that generate revenue credits and offset the cost of PacifiCorp's transmission revenue requirement. The new transmission investment is considered a network transmission asset under PacifiCorp's OATT and therefore will be given rolled-in treatment under the company's transmission formula rate. Over recent history, these revenue credits have accounted for approximately 12 percent of PacifiCorp's transmission revenue requirement. Based on this recent history, PacifiCorp's analysis continues to assume its retail customers pay 88 percent of the revenue requirement from the up-front capital cost of the new transmission investment after accounting for an assumed 12 percent revenue credit from other transmission customers.

Avoided De-Rate Benefits

In its final 2017 IRP resource-portfolio screening process, PacifiCorp identified and quantified reliability benefits associated with the Aeolus-to-Bridger/Anticline transmission project. This new transmission project would eliminate de-rates caused by outages on 230-kV transmission system elements. Historical outages on this part of PacifiCorp's transmission system indicate an average de-rate of 146 MW over approximately 88 outage days per year, which equates to approximately one 146-MW, 24-hour outage every four days. Without knowing when these events might occur, de-rates on the existing 230-kV transmission system were captured in the SO model and PaR as a 36.5 MW reduction in the transfer capability from eastern Wyoming to the Aeolus area. In simulations that include the new wind and transmission, this de-rate assumption was eliminated when the new transmission project is assumed to be placed in service at the end of October 2020.

Line Loss Benefits

Line-loss benefits are only applicable if the Aeolus-to-Bridger/Anticline transmission project is built and therefore were only considered in the simulations that include the new wind and transmission. In these simulations, when the Aeolus-to-Bridger/Anticline transmission project is added in parallel to the existing transmission lines, resistance is reduced, which lowers line losses. With reduced line losses, an incremental 11.6 average MW (aMW) of energy, which equates to approximately 102 GWh, will be able to flow out of eastern Wyoming each year. The line-loss benefit was reflected in the SO model and PaR by reducing northeast Wyoming load by approximately 11.6 aMW each year.

EIM Benefits

In its final 2017 IRP resource-portfolio screening process, PacifiCorp described how the Energy Imbalance Market (EIM) can provide potential benefits when incremental energy is added to transmission-constrained areas of Wyoming. Unscheduled or unused transmission from participating EIM entities enables more efficient power flows within the hour. With increasing participation in the EIM, there will be increasing opportunities to move incremental energy from Wyoming to offset higher-priced generation in the PacifiCorp system or other EIM participants' systems. The more efficient use of transmission that is expected with growing participation in the EIM was captured in the updated economic analysis by increasing the transfer capability between the east and west sides of PacifiCorp's system by 300 MW (from the Jim Bridger plant to south-central Oregon). The ability to more efficiently use intra-hour transmission from a growing list of EIM participants is not driven by the Energy Vision 2020 projects; however, this increased connectivity provides the opportunity to move low-cost incremental energy out of transmission-constrained areas of Wyoming.

Investment Recovery

As was assumed in the 2017 IRP, the updated economic analysis continues to assume that PacifiCorp will fully recover the unrecovered investment in the original equipment on existing wind resources and earn its authorized rate of return on the unrecovered balance over the remainder of the original 30-year depreciable life of each repowered wind facility. PacifiCorp does not assume any salvage value for the equipment that will be replaced with repowering; however, any salvage value for the existing equipment would decrease the unrecovered investment and increase customer benefits.

SECTION 3 - WIND REPOWERING

Wind Repowering Scope

To assess the scope of the wind repowering project, PacifiCorp completed a series of SO model and PaR studies to determine how the system PVRR changes when a specific wind facility is added or removed from the scope of the wind repowering project. Starting with the wind repowering scope assumed in the 2017 IRP preferred portfolio, covering 905 MW of existing wind resource capacity, PacifiCorp first removed the Leaning Juniper facility from the wind repowering scope because it has the lowest expected annual average capacity factor among the owned wind facilities in PacifiCorp's wind fleet. A wind facility's capacity factor is a strong indicator of whether repowering is cost-effective because it is representative of energy output and is therefore tied to the amount of PTCs that will be generated if the facility is repowered. The risk-adjusted system PVRR from the case eliminating Leaning Juniper from the wind repowering project scope was $7 million higher than the risk-adjusted system PVRR from the case including Leaning Juniper in the project scope. Based on these results, Leaning Juniper remains within the scope of the wind repowering project considered in PacifiCorp's updated economic analysis.

Because repowering of the Leaning Juniper facility, which has the lowest expected annual capacity factor relative to other wind facilities in PacifiCorp's fleet, provides incremental net benefits, all remaining wind facilities within the project scope would generate more PTCs and provide even larger incremental net benefits if repowered. Consequently, PacifiCorp did not analyze any further reductions to the wind repowering scope beyond its analysis of Leaning Juniper.

PacifiCorp next evaluated how expanding the wind repowering scope to include Goodnoe Hills would affect the system PVRR. The risk-adjusted system PVRR from the case including Goodnoe Hills in the project scope was $20 million lower than the system PVRR from the case without Goodnoe Hills. Based on these results, Goodnoe Hills was added to the repowering project scope considered in PacifiCorp's updated economic analysis. With Goodnoe Hills included in the scope of the repowering project, the updated economic analysis covers 999.1 MW of existing wind capacity—594 MW of this capacity is located in Wyoming (Glenrock I and III, Rolling Hills, Seven Mile Hill I and II, High Plains, McFadden Ridge, and Dunlap), 100.5 MW is located in Oregon (Leaning Juniper), and 304.6 MW is located in Washington (Marengo I and II, and Goodnoe Hills).

System Modeling Price-Policy Results

Table 3.1 summarizes the PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without wind repowering are shown from the SO model and from PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data that was used to calculate the PVRR(d) results shown in the table are provided as Attachment B.

Table 3.1 – SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	$33	$43	$44
Low Gas, Medium CO_2	$0	$9	$8
Low Gas, High CO_2	($18)	($17)	($19)
Medium Gas, Zero CO_2	($33)	($24)	($25)
Medium Gas, Medium CO_2	($22)	($13)	($15)
Medium Gas, High CO_2	($41)	($35)	($36)
High Gas, Zero CO_2	($75)	($40)	($43)
High Gas, Medium CO_2	($64)	($34)	($37)
High Gas, High CO_2	($103)	($80)	($85)

Over a 20-year period, before accounting for the increase in incremental energy output beyond 2036, the wind repowering project reduces customer costs in seven out of nine price-policy scenarios. This trend occurs in the PVRR(d) calculated from both the SO model and PaR. The only price-policy scenarios without net customer benefits are those assuming the lowest natural gas prices when paired with either medium or zero CO_2 price assumptions. The PVRR(d) results show customer benefits under the price-policy scenario with low natural gas prices and high CO_2 prices, in all three of the medium-natural-gas-price scenarios, and in all three of the high-natural-gas-price scenarios. Under the central price-policy scenario, assuming medium-natural-gas prices and medium CO_2 prices, the PVRR(d) benefits range between $13 million, when based upon PaR-stochastic-mean results, and $22 million, when based upon SO model results.

The PVRR(d) results show that the benefits of the wind repowering project increase with natural gas prices and CO_2 prices. PVRR(d) results for scenarios where medium CO_2 prices are assumed with medium or high natural gas prices show a slight drop in benefits relative the zero-CO_2-price scenarios. This tends to be driven by changes to the timing of new resources in the outer years of the 20-year forecast period and would not likely persist if longer simulation periods were feasible.

The PVRR(d) results presented in Table 3.1 do not reflect the potential value of RECs generated by the incremental wind energy output from the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $4 million for every dollar assigned to the incremental RECs that will be generated from the repowered wind facilities through 2036.

Model Differences

The two models assess the system impacts of the wind repowering project in different ways. The SO model is designed to dynamically assess system dispatch, with less granularity than PaR, while optimizing the selection of resources to the portfolio over time. PaR is able to dynamically assess system dispatch with more granularity than the SO model and with consideration of stochastic risk variables; however, PaR does not modify the type, timing, size and location of resources in the portfolio in response to its more detailed assessment of system dispatch. In evaluating differences in annual system costs between the two models, PaR's ability to better simulate system dispatch relative to the SO model results in lower benefits from repowering being reported from PaR in the earlier years of the forecast horizon. Because PaR cannot modify resource selections in response to its assessment of system dispatch, this effect is softened over the longer term, when changes to the resource portfolio in response to wind repowering are more notable.

Note that SO and PaR, while different, are both useful in establishing a range of wind repowering benefits through the 20-year forecast period. Importantly, the PVRR(d) results from both models show customer benefits across the same set of price-policy scenarios with consistent trends in the difference in PVRR(d) results between price-policy scenarios. The consistency in the trend of forecasted benefits between the two models, each having its own strengths, shows that the wind repowering benefits are robust across a range of price-policy assumptions and when analyzed using different modeling tools.

The risk-adjusted PVRR(d) results are very similar to the stochastic-mean PVRR(d) results. This indicates that the wind repowering project does not materially affect high-cost, low-probability outcomes that can occur due to volatility in stochastic variables like load, wholesale-market prices, hydro generation, and thermal-unit outages.

Annual Revenue Requirement Price-Policy Results

Table 3.2 summarizes the 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 Attachment C.

Table 3.2 – Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

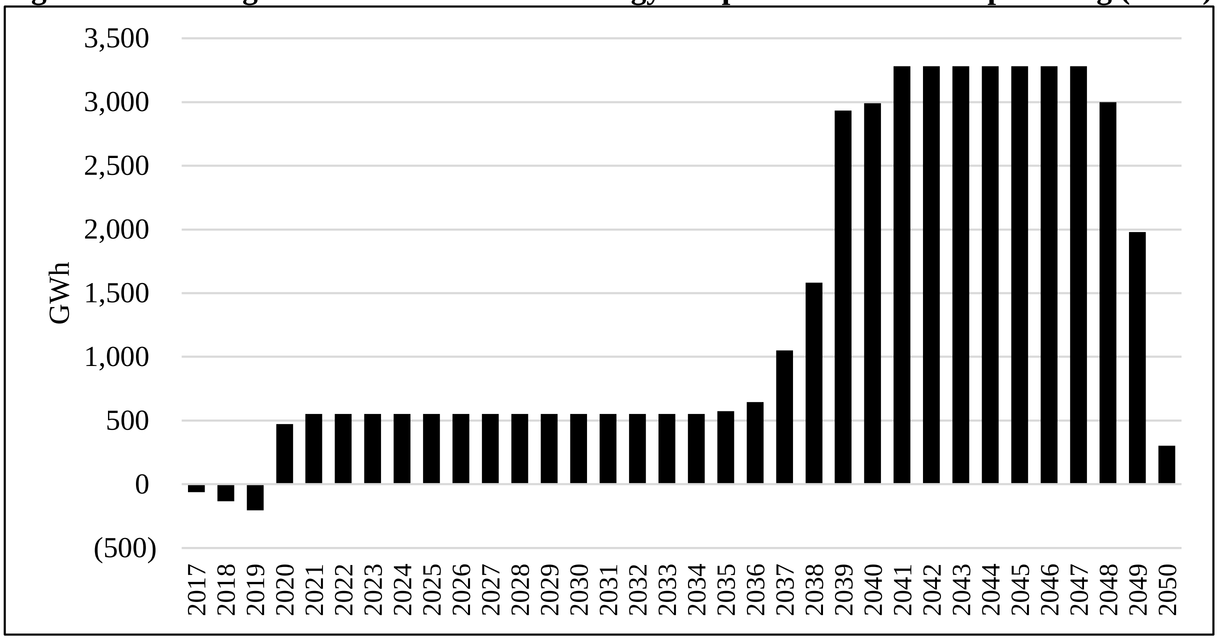
Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($41)
Low Gas, Medium CO_2	($245)
Low Gas, High CO_2	($344)
Medium Gas, Zero CO_2	($362)
Medium Gas, Medium CO_2	($359)
Medium Gas, High CO_2	($401)
High Gas, Zero CO_2	($400)
High Gas, Medium CO_2	($274)
High Gas, High CO_2	($589)

When calculated through 2050, which covers the remaining life of the repowered facilities, the wind repowering project reduces customer costs in all nine price-policy scenarios, with PVRR(d) benefits ranging from $41 million in the low- natural-gas-and-zero-CO_2 scenario to $589 million in the high-natural-gas-and-high-CO_2 scenario. Under the central price-policy scenario, assuming medium natural gas prices and medium CO_2 prices, the PVRR(d) benefits are $359 million.

The PVRR(d) calculated from estimated annual revenue requirement through 2050 picks up the sizable increase in incremental wind energy output beyond the 20-year forecast period analyzed with the SO model and PaR. As mentioned previously, the change in wind energy output between cases with and without wind repowering experiences a step change beyond this 20-year period, when the existing wind facilities would otherwise have hit the end of their depreciable life. Beyond the 20-year forecast period, the change in wind energy output between cases with and without repowering reflects the full energy output from the repowered wind facilities.

Figure 3.1 shows the incremental change in wind energy output resulting from the repowering project. Incremental energy output associated with wind repowering progressively increases over the 2036-through-2040 period, as wind facilities originally placed in service in the 2006-through-2010 time frame would have otherwise hit the end of their lives. Before 2036, and once all of the wind resources within the project scope are repowered, the average annual incremental increase in wind energy output is approximately 551 GWh. Beyond 2040, and before the new equipment hits the end of its depreciable life, the average annual incremental increase in wind-energy output is approximately 3,283 GWh.

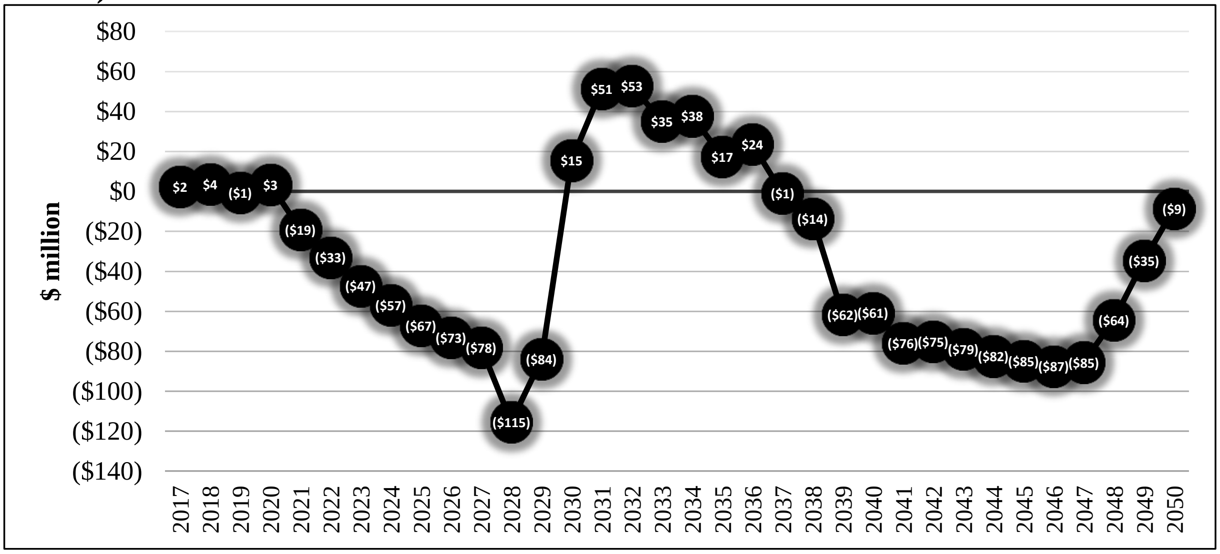
Figure 3.1 – Change in Incremental Wind Energy Output Due to Wind Repowering (GWh)



As in the case with the PVRR(d) results calculated from the SO model and PaR results through 2036, the PVRR(d) results presented in Table 3.2 do not reflect the potential value of RECs produced by the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $11 million for every dollar assigned to the incremental RECs that will be generated from the wind repowering project through 2050.

Figure 3.2 shows the estimated change in nominal revenue requirement due to wind repowering for the medium-natural-gas-and-medium-CO_2 price-policy scenario on a total-system basis. The change in nominal revenue requirement shown in the figure reflects project costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), operations and maintenance expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against system impacts of wind repowering, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the wind repowering project.

Figure 3.2 – Total-System Annual Revenue Requirement with Wind Repowering ($ million)



Before repowering, the reduction in wind energy output due to component failures on the existing wind resource equipment is assumed to reduce wind energy output for specific wind turbines until the time new equipment is installed. This contributes to a slight increase in revenue requirement in 2017 and 2018 ($2 million to $4 million, total system). All but the Dunlap facility, which is repowered toward the end of 2020, are repowered in 2019. Over the 2019-to-2020 time frame, project costs reflecting partial-year capital revenue requirement net of PTCs and system cost impacts cause slight changes to revenue requirement.

The wind repowering project reduces revenue requirement soon after the new equipment is placed in service in the 2019-to-2020 time frame. From 2021 through 2028, annual revenue requirement is reduced as PTC benefits increase with inflation and the new equipment continues to depreciate. On a total-system basis, annual revenue requirement is reduced by $19 million in 2021. The reduction in annual revenue requirement increases to $115 million by 2028. Revenue requirement increases once the PTCs expire toward the end of 2030. Annual revenue requirement is reduced over the 2037-through-2050 time frame when, as discussed previously, the incremental wind energy output associated with wind repowering increases substantially.

Sensitivity Studies

40-Year Life Sensitivity

The 40-year life sensitivity quantifies how the net benefits of wind repowering are affected by the depreciable life of repowered facilities. PacifiCorp's base analysis assumes that repowering will reset the 30-year depreciable life of the asset. Assuming the possibility that wind facilities with modern equipment might continue operating over a longer period, this sensitivity quantifies the economic impact if the depreciable life of new equipment on a repowered facility were reset at 40 years.

Table 3.3 summarizes the PVRR(d) results for the sensitivity assuming a 40-year life for new equipment. To assess the relative impact of the 40-year life, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study in which wind repowering was evaluated with a 30-year life. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 3.3 – 40-Year-Life Sensitivity (Benefit)/Cost ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($60)	($22)	($38)
PaR Stochastic-Mean	($50)	($13)	($37)
PaR Risk-Adjusted	($52)	($15)	($37)

If the new equipment were depreciated over a 40-year life, reduced book depreciation would drive lower annual revenue requirement. In this sensitivity, PVRR(d) benefits increase by approximately $37 million relative to the benchmark case assuming a 30-year life for the new equipment.

New Wind and Transmission Sensitivity

The new-wind-and-transmission sensitivity quantifies how the net benefits of wind repowering are affected when combined with 1,180 MW of new Wyoming wind resources (860 MW of owned resources and 320 MW of contracted resources) and the Aeolus-to-Bridger/Anticline transmission project. Consistent with PacifiCorp's CPCN applications for the new wind and transmission assets, this sensitivity assumes the new wind and transmission is operational by the end of October 2020.

Table 3.4 summarizes the PVRR(d) results for the sensitivity assuming wind repowering is implemented along with 1,180 MW of new Wyoming wind and the Aeolus-to-Bridger/Anticline transmission project. To assess the relative impact of the new wind and transmission, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study in which wind repowering was evaluated as a stand-alone project. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 3.4 – New Wind and Transmission Sensitivity (Benefit)/Cost ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($114)	($22)	($91)
PaR Stochastic-Mean	($104)	($13)	($90)
PaR Risk-Adjusted	($116)	($15)	($101)

When the wind repowering project is combined with 1,180 MW of new Wyoming wind and the Aeolus-to-Bridger/Anticline transmission project, PVRR(d) benefits increase by between $91 million to $101 million relative to the benchmark case. This sensitivity shows that wind repowering benefits persist when combined with new wind and new transmission, and that the new wind and new transmission will provide significant incremental benefits for customers.

Wind Repowering Capacity Sensitivity

The wind repowering capacity sensitivity builds on the new-wind-and-transmission sensitivity case by assessing how the net benefits of wind repowering are affected if the repowered facilities are able to operate at their full generating capability. This sensitivity assumes the additional capacity and energy is combined with the new wind and new transmission included in the prior sensitivity. PacifiCorp's base analysis assumes that the repowered wind facilities continue to operate within the limits of their existing large-generator interconnection agreements (LGIAs). The average incremental energy output is expected to increase by approximately 19.2 percent if the repowered facilities operate within their existing LGIA limits. If these limits are modified, the average incremental energy output rises to 20.8 percent. PacifiCorp is studying whether these LGIAs can be modified to increase incremental energy output from the repowered facilities, which would increase the net benefits of repowering.

Table 3.5 summarizes the PVRR(d) results for this sensitivity that assumes repowered wind facilities can operate at their full capacity. The increased energy and capacity assumed in this sensitivity is in addition to the new wind and transmission assumed in the prior sensitivity. To assess the relative impact of this assumption on revenue requirement, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study assuming repowered wind resources operate within existing LGIA limits. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 3.5 – Increased Wind Repower Capacity Sensitivity (Benefit)/Cost ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($109)	($114)	$4
PaR Stochastic-Mean	($106)	($104)	($2)
PaR Risk-Adjusted	($118)	($116)	($2)

If PacifiCorp is able to modify its LGIAs, the repowered wind facilities will be able to produce additional energy in those hours where wind energy output would otherwise have been curtailed to stay within current LGIA limits. If these LGIAs are modified, this study suggests there may be additional upside to customer benefits, but they are not likely to be substantial.

Conclusion

PacifiCorp's analysis supports repowering approximately 999 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington. The repowered wind facilities will qualify for an additional ten years of federal PTCs, produce more energy, reset the 30-year depreciable life of the assets, and reduce run-rate operating costs. The economic analysis of the wind repowering opportunity demonstrates that net benefits, which include federal PTC benefits, NPC benefits, other system variable-cost benefits, and system fixed-cost benefits, more than outweigh net project costs.

SECTION 4 – NEW WIND AND TRANSMISSION

System Modeling Price-Policy Results

Table 4.1 summarizes the PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without the new wind and transmission projects are shown from the SO model and from PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data that was used to calculate the PVRR(d) results shown in the table are provided as Attachment D.

Table 4.1 – SO Model and PaR PVRR(d) (Benefit)/Cost of New Wind and Transmission ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	$121	$77	$74
Low Gas, Medium CO_2	$73	$32	$26
Low Gas, High CO_2	($84)	($133)	($147)
Medium Gas, Zero CO_2	($19)	($57)	($66)
Medium Gas, Medium CO_2	($85)	($111)	($124)
Medium Gas, High CO_2	($156)	($224)	($242)
High Gas, Zero CO_2	($304)	($260)	($280)
High Gas, Medium CO_2	($318)	($272)	($293)
High Gas, High CO_2	($396)	($409)	($437)

Over a 20-year period, the new wind and transmission projects reduce customer costs in seven out of nine price-policy scenarios price-policy scenarios. This trend occurs in the PVRR(d) calculated from both the SO model and PaR. The only price-policy scenarios without net customer benefits are those assuming the lowest natural-gas prices when paired with either medium or zero-CO_2 price assumptions. Under the central price-policy scenario, assuming medium-natural-gas prices and medium-CO_2 prices, the PVRR(d) benefits range between $85 million, when based upon SO model results, and $124 million, when based upon PaR-risk-adjusted results. The PVRR(d) results show that the benefits of the Combined Projects increase with natural-gas prices and CO_2 prices, which increase NPC and other system variable cost benefits.

The PVRR(d) results presented in Table 4.1 do not reflect the potential value of RECs generated by the incremental energy output from the new Wyoming wind resources. Customer benefits for all price-policy scenarios would improve by approximately $26 million for every dollar assigned to the incremental RECs that will be generated from the new wind resources through 2036. Beyond potential REC-revenue benefits, the economic analysis of the new wind and transmission does not reflect PacifiCorp's enhanced ability to comply with mandated reliability and performance standards and the opportunity for further increases to the transfer capability across the Aeolus-to-Bridger/Anticline Line with the construction of additional segments of the Energy Gateway Project.

Model Differences

As is the case in the wind repowering economic analysis, the two models assess the system impacts of the new wind and transmission in different ways. The SO model is designed to dynamically assess system dispatch, with less granularity than PaR, while optimizing the selection of resources to the portfolio over time. PaR is able to dynamically assess system dispatch, with more granularity than the SO model and with consideration of stochastic risk variables; however, PaR does not modify the type, timing, size and location of resources in the portfolio in response to its more detailed assessment of system dispatch.

The two models are simply different, and both are useful in establishing a range of benefits from the new wind and transmission through the 20-year forecast period. Importantly, the PVRR(d) results from both models show customer benefits across all price-policy scenarios with consistent trends in the difference in PVRR(d) results between price-policy scenarios. The consistency in the trend of forecasted benefits between the two models, each having its own strengths, shows that the benefits from the new wind and transmission are robust across a range of price-policy assumptions and when analyzed using different modeling tools.

The risk-adjusted PVRR(d) results consistently show a slight increase in the benefits of the new wind and transmission when compared to the stochastic-mean PVRR(d) results. This indicates that the investments reduce the risk of high-cost, low-probability outcomes that can occur due to volatility in stochastic variables like load, wholesale-market prices, hydro generation, and thermal-unit outages.

Annual Revenue Requirement Price-Policy Results

Table 4.2 summarizes the 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 Attachment E.

Table 4.2 – Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the New Wind and Transmission ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	$174
Low Gas, Medium CO_2	$93
Low Gas, High CO_2	($194)
Medium Gas, Zero CO_2	($53)
Medium Gas, Medium CO_2	($137)
Medium Gas, High CO_2	($317)
High Gas, Zero CO_2	($341)
High Gas, Medium CO_2	($351)
High Gas, High CO_2	($595)

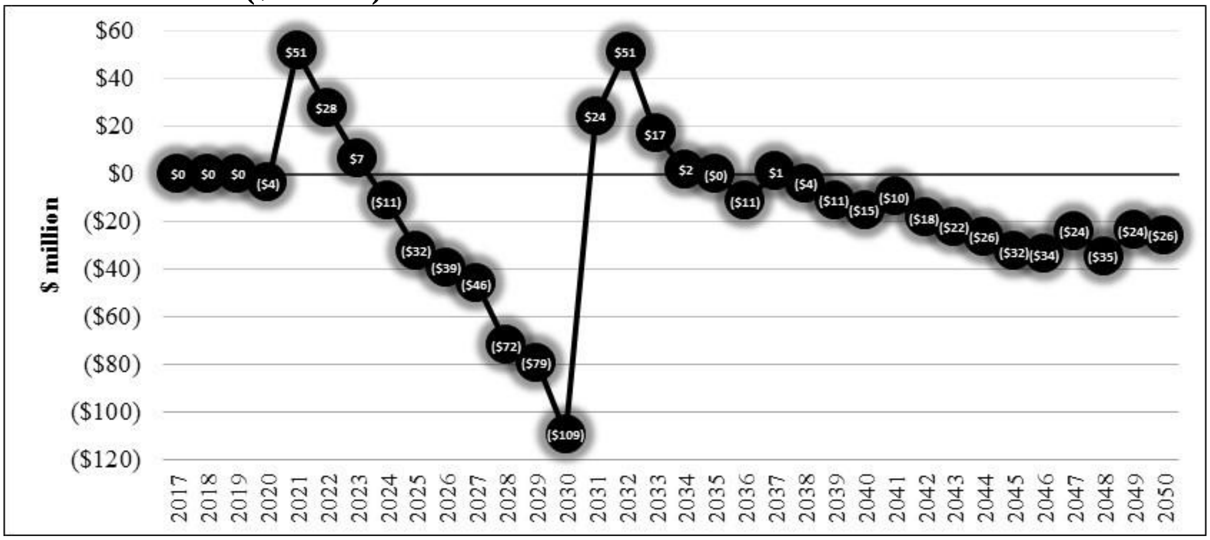
When calculated through 2050, which covers the 30-year life of the new wind resources, the new wind and transmission reduce customer costs in seven out of nine price-policy scenarios. The only price-policy scenarios without net customer benefits are those assuming the lowest natural-gas prices when paired with either medium or zero-CO_2 price assumptions. The PVRR(d) results show customer benefits under the price-policy scenario with low natural-gas prices and high-CO_2 prices, in all three of the medium-natural-gas price scenarios, and in all three of the high-natural-gas price scenarios. Under the central price-policy scenario, assuming medium-natural-gas prices and medium-CO_2 prices, the PVRR(d) benefit is $137 million. Consistent with the PVRR(d) results calculated from the SO model and PaR through 2036, the PVRR(d) results show that the benefits of the new wind and transmission increase with natural-gas prices and CO_2 prices, which increase NPC and other system variable cost benefits.

The PVRR(d) calculated from estimated annual revenue requirement through 2050 reflects reduced incremental wind energy output beginning in 2042 after the PPAs for the 320 MW of QF resources end. Incremental energy output associated from the new wind resources is steady over the 2022-through-2041 period. Beyond 2041, energy output is approximately drops by nearly 27 percent once the QF PPAs terminate. This reduction in incremental wind energy output reduces NPC benefits and other system variable costs benefits over the last nine years of the PVRR(d) calculated off the change in nominal revenue requirement estimates through 2050. Consequently, the PVRR(d) calculated off the change in nominal revenue requirement through 2050 does not capture likely benefits associated with a potential extension of the QF Projects' PPAs or incremental procurement of additional Wyoming wind resources after the term of these PPAs end.

As in the case with the PVRR(d) results calculated from the SO model and PaR results through 2036, the PVRR(d) results presented in Table 4.2 do not reflect the potential value of RECs produced by the new wind resources. Customer benefits for all price-policy scenarios would improve by approximately $34 million for every dollar assigned to the incremental RECs that will be generated from these resources through 2050.

Figure 4.1 shows the estimated change in annual nominal-revenue requirement due to the new wind and transmission for the medium-natural-gas and medium-CO_2-price-policy scenario on a total-system basis. The annual revenue requirement shown in the figure reflects all costs for these investments, including capital revenue requirement (i.e., depreciation, return, income taxes, and property taxes) net of transmission revenue credits, operations and maintenance expenses, the Wyoming wind-production tax, incremental wind integration costs, and PTCs. The project costs are netted against system impacts of the new wind and transmission, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, these investments.

Figure 4.1 – Total-System Change in Annual Revenue Requirement Due to the New Wind and Transmission ($ million)



In the initial year that the new wind and transmission assets come online, net system benefits offset partial-year capital revenue requirement. In 2021, the first full year the new wind and transmission are in service, the change in total-system nominal revenue requirement increases by $51 million. This figure rapidly declines and crosses over from a net increase in nominal revenue requirement to a decrease in nominal revenue requirement beginning 2024—just four years after the first full year of operation. The net revenue requirement benefits persist and grow through 2030 as PTC benefits increase with inflation and the new equipment continues to depreciate. On a total-system basis, the change in annual revenue requirement is down by $109 million in 2030—the last year the new wind resources produce PTCs. After the PTCs expire, annual revenue requirement increases. However, as the assets continue to depreciate, the new wind and transmission once again begin producing annual revenue requirement savings beginning 2036. These annual benefits persist through 2050.

Sensitivity Studies

40-Year Life Sensitivity

The 40-year life sensitivity quantifies how the net benefits of the new wind and transmission are affected by the depreciable life assumed for the new wind resources. PacifiCorp's base analysis assumes a 30-year depreciable life when calculating revenue requirement associated with the 860 MW of proxy benchmark wind resources included in the analysis. Considering that wind facilities with modern equipment might continue operating over a longer period, this sensitivity quantifies the economic impact if the depreciable life of these assets were reset at 40 years.

Table 4.3 summarizes the PVRR(d) results for the sensitivity assuming a 40-year life for the 860 MW of proxy benchmark wind resources. To assess the relative impact of the 40-year life, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study in which the new wind and transmission were evaluated assuming a 30-year life for these new wind facilities. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 4.3 – 40-Year-Life Sensitivity (Benefit)/Cost ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($106)	($85)	($21)
PaR Stochastic-Mean	($132)	($111)	($21)
PaR Risk-Adjusted	($145)	($124)	($21)

If the 860 MW of new wind assets are depreciated over a 40-year life, reduced book depreciation would drive lower annual revenue requirement. In this sensitivity, PVRR(d) benefits increase by approximately $21 million relative to the benchmark case.

Wind Repowering Sensitivity

The wind repowering sensitivity quantifies how the net benefits of the new wind and transmission are affected when paired with the wind repowering project. Consistent with PacifiCorp's wind repowering analysis, this sensitivity assumes approximately 999 MW of existing wind resource capacity is upgraded with modern equipment in the 2019-to-2020 time frame.

Table 4.4 summarizes the PVRR(d) results for the sensitivity assuming the new wind and transmission are implemented along with wind repowering of approximately 999 MW of existing wind capacity. To assess the relative impact of wind repowering on the new wind and transmission, the PVRR(d) results were calculated through 2036 based on SO model and PaR results and are presented alongside the benchmark study in which the new wind and transmission were evaluated without repowering. Medium-natural-gas and medium-CO_2 price-policy assumptions were applied to this sensitivity.

Table 4.4 – Wind Repowering Sensitivity (Benefit)/Cost ($ million)

Model	Sensitivity PVRR(d)	Benchmark PVRR(d)	Change in PVRR(d)
SO Model	($114)	($85)	($29)
PaR Stochastic-Mean	($104)	($111)	$8
PaR Risk-Adjusted	($116)	($124)	$8

When the new wind and transmission are analyzed with the wind repowering project, PVRR(d) benefits increase by $29 million when assessed with the SO model. PaR shows a slight $8 million increase to the PVRR(d) relative to the benchmark.

The sensitivity does not capture any of the incremental benefits from the wind repowering project that will occur just beyond the 2036 period, which is the last year simulated in the SO model and PaR. Consequently, the PVRR(d) results from the SO model and PaR do not capture the significant increase in the benefits from repowering that is associated with increased incremental energy output that will occur beyond 2036.

As described in Section 3 of this informational update, the change in wind energy output between cases with and without repowering experiences a step change in the 2036-through-2040 time frame, when the wind facilities within the repowering project scope that were originally placed in-service during the 2006-through-2010 time frame would otherwise have hit the end of their depreciable life. Before the 2036-through-2040 time frame, the period captured in the PVRR(d) results summarized in Table 4.4, the change in wind energy output from repowering reflects the incremental energy production that results from installing modern equipment on repowered wind assets. Beyond the 2036-through-2040 time frame, a period that is not captured in the PVRR(d) results reported in Table 4.4, the change in wind energy output between a case with and without repowering reflects the full energy output from the repowered wind facilities that would otherwise be retired (see Figure 3.1 in Section 3).

Conclusion

PacifiCorp's analysis supports proceeding with its planned investments in the new wind and transmission included in the 2017 IRP preferred portfolio.

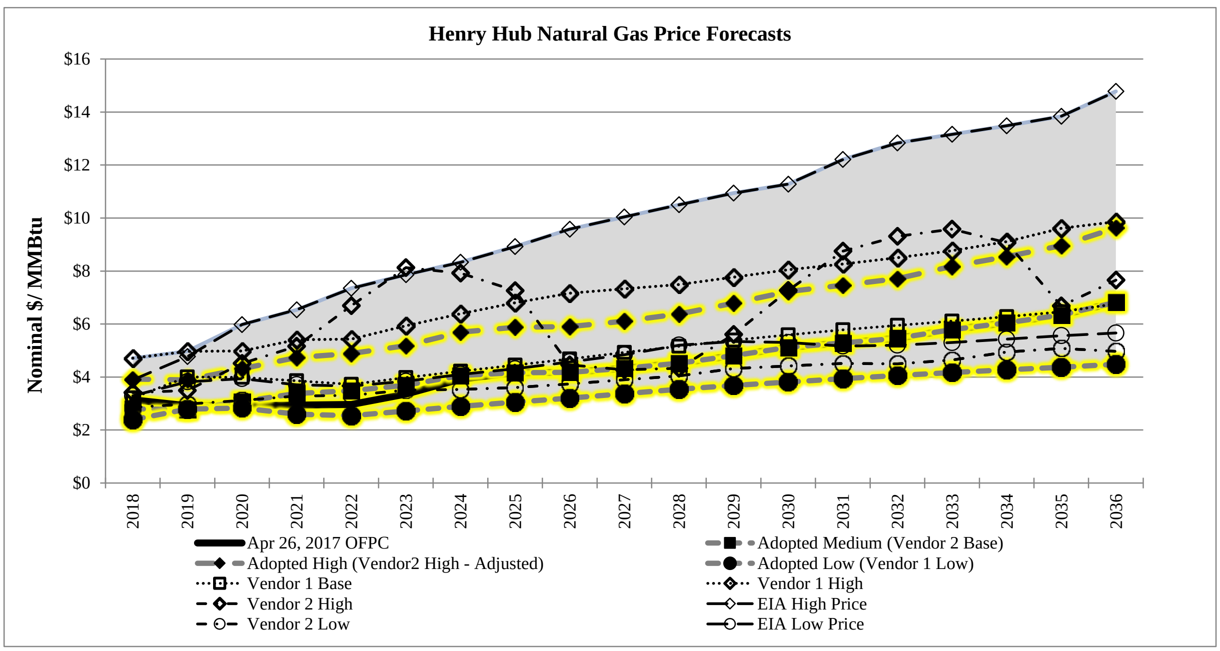
The new wind resources, which are enabled by the Aeolus-to-Bridger/Anticline transmission line will: (1) qualify for ten years of federal PTCs; (2) produce zero-fuel-cost energy that will lower NPC; (3) generate RECs, which can be sold in the market to create additional revenues that would lower net customer costs or otherwise be applied to meeting state renewable procurement targets; and (4) help to decarbonize PacifiCorp's resource portfolio, which mitigates long-term risk associated with potential future state and federal policies targeting CO_2 emissions reductions from the electric sector.

The Aeolus-to-Bridger/Anticline transmission line will: (1) relieve congestion on the current transmission system in eastern Wyoming; (2) enable the additional wind resource interconnections; (3) provide critical voltage support to the Wyoming transmission network; (4) improve overall reliability of the transmission system and enhance PacifiCorp's ability to comply with mandated reliability and performance standards; (5) reduce line losses; and (6), create an opportunity for further increases to the transfer capability across the Aeolus-to-Bridger/Anticline line with the construction of additional segments of the Energy Gateway project.

The updated economic analysis of the new wind and transmission in the 2017 IRP preferred portfolio demonstrates that net benefits more than outweigh net project costs.

ATTACHMENT A – NOMINAL HENRY HUB NATURAL GAS PRICE FORECASTS ($/MMBTU)

Year	Apr 26, 2017 OFPC	Adopted Medium (Vendor 2 Base)	Adopted High (Vendor2 High - Adjusted)	Adopted Low (Vendor 1 Low)	Vendor 1 Base	Vendor 1 High	Vendor 2 High	EIA Low Price	EIA High Price	Vendor 2 Low	Lowest Price	Highest Price	Range
2018	$3.14	$2.80	$3.92	$2.39	$3.21	$4.71	$3.41	$3.29	$3.89	$2.85	$2.39	$4.71	$2.32
2019	$2.92	$2.77	$3.89	$2.79	$4.00	$4.97	$3.49	$3.82	$4.77	$2.98	$2.77	$4.97	$2.20
2020	$2.92	$3.08	$4.32	$2.83	$3.99	$4.98	$4.51	$3.94	$5.98	$3.12	$2.83	$5.98	$3.15
2021	$2.94	$3.38	$4.74	$2.60	$3.86	$5.41	$5.16	$3.71	$6.54	$3.28	$2.60	$6.54	$3.94
2022	$2.97	$3.48	$4.89	$2.54	$3.72	$5.43	$6.69	$3.66	$7.35	$3.31	$2.54	$7.35	$4.81
2023	$3.35	$3.69	$5.18	$2.72	$3.98	$5.93	$8.13	$3.84	$7.86	$3.51	$2.72	$7.86	$5.14
2024	$3.92	$4.06	$5.69	$2.89	$4.22	$6.39	$7.92	$4.10	$8.33	$3.53	$2.89	$8.33	$5.44
2025	$4.16	$4.16	$5.88	$3.05	$4.45	$6.80	$7.26	$4.31	$8.92	$3.60	$3.05	$8.92	$5.87
2026	$4.18	$4.18	$5.90	$3.20	$4.68	$7.16	$4.46	$4.57	$9.58	$3.74	$3.20	$9.58	$6.38
2027	$4.33	$4.33	$6.11	$3.37	$4.93	$7.33	$4.27	$4.84	$10.04	$3.90	$3.37	$10.04	$6.67
2028	$4.52	$4.52	$6.38	$3.54	$5.16	$7.49	$4.33	$5.20	$10.50	$4.04	$3.54	$10.50	$6.96
2029	$4.81	$4.81	$6.79	$3.68	$5.39	$7.77	$5.61	$5.34	$10.94	$4.32	$3.68	$10.94	$7.26
2030	$5.12	$5.12	$7.23	$3.81	$5.59	$8.05	$7.27	$5.30	$11.28	$4.42	$3.81	$11.28	$7.47
2031	$5.28	$5.28	$7.46	$3.94	$5.78	$8.26	$8.75	$5.17	$12.21	$4.51	$3.94	$12.21	$8.27
2032	$5.46	$5.46	$7.71	$4.06	$5.95	$8.50	$9.31	$5.20	$12.83	$4.50	$4.06	$12.83	$8.77
2033	$5.79	$5.79	$8.17	$4.17	$6.11	$8.77	$9.58	$5.30	$13.16	$4.64	$4.17	$13.16	$8.99
2034	$6.05	$6.05	$8.54	$4.27	$6.28	$9.11	$9.07	$5.43	$13.48	$4.94	$4.27	$13.48	$9.21
2035	$6.34	$6.34	$8.95	$4.37	$6.46	$9.61	$6.68	$5.56	$13.84	$5.08	$4.37	$13.84	$9.47
2036	$6.82	$6.82	$9.63	$4.48	$6.76	$9.86	$7.66	$5.66	$14.78	$4.97	$4.48	$14.78	$10.30



ATTACHMENT B – SYSTEM MODELING PRICE-POLICY DETAIL FOR WIND REPOWERING

SO Model Annual Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($107)	$1	$3	$2	($9)	($11)	($11)	($12)	($12)	($13)	($13)	($14)	($17)	($18)	$8	($3)	($25)	($29)	($24)	($22)	($21)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($12)	$0	($0)	($1)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($3)	($1)	($1)	($1)	$0	$0	$0	$0	$0
Change in System Fixed Cost	$17	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$4	$4	($35)	$15	$28	$20	$12	$3	$1
Net (Benefit)/Cost	$33	$12	$13	$12	$1	($1)	($1)	($2)	($2)	($3)	($3)	($3)	($2)	($2)	($14)	$25	$17	$6	$3	($3)	($4)

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($230)	$1	$2	$1	($11)	($13)	($14)	($14)	($15)	($15)	($16)	($14)	($18)	($42)	($52)	($50)	($53)	($59)	($61)	($64)	($67)
Change in Emissions	$14	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($0)	($1)	($0)	($1)	$5	$5	$6	$7	$7	$9	$9
Change in DSM	$11	$0	$1	$1	$1	$2	$2	$2	$2	$2	$2	$2	$2	$1	$1	$1	$0	$0	($0)	($2)	($2)
Change in System Fixed Cost	$71	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($3)	$37	$28	$19	$16	$25	$25	$25	$27
Net (Benefit)/Cost	($0)	$12	$13	$13	$1	($1)	($1)	($1)	($1)	($2)	($3)	$0	($7)	$9	($4)	($12)	($16)	($12)	($14)	($17)	($18)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($126)	$1	$3	$2	($11)	($13)	($13)	($13)	($13)	($15)	($16)	($15)	($17)	($17)	($19)	($19)	($20)	($21)	($22)	($23)	($24)
Change in Emissions	($26)	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($1)	($4)	($5)	($7)	($6)	($7)	($8)	($8)	($8)	($8)	($7)
Change in DSM	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	($0)
Change in System Fixed Cost	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	($0)
Net (Benefit)/Cost	($18)	$12	$13	$12	$0	($1)	($1)	($2)	($1)	($3)	($4)	($6)	($9)	($10)	($11)	($12)	($14)	($14)	($15)	($15)	($15)

SO Model Annual Results ($ million)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($186)	$2	$3	$2	($10)	($13)	($14)	($15)	($16)	($17)	($17)	($17)	($59)	($35)	($20)	($24)	($60)	($28)	($29)	($30)	($32)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($2)	$0	($0)	($0)	$0	$0	$0	$0	$0	($0)	($1)	($1)	($1)	($0)	($0)	$0	($0)	($0)	($0)	($2)	($2)
Change in System Fixed Cost	$21	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$60	($32)	($23)	($19)	$63	$1	$1	$1	$2
Net (Benefit)/Cost	($33)	$12	$13	$12	$1	($1)	($2)	($3)	($4)	($5)	($5)	($5)	$13	($54)	($29)	($29)	$18	($13)	($14)	($15)	($16)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($293)	$1	$3	$1	($12)	($15)	($19)	($21)	($23)	($24)	($25)	($26)	($30)	($31)	($48)	($82)	($109)	($66)	($70)	($22)	($99)
Change in Emissions	($15)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($2)	($1)	($5)	($9)	($10)	($2)	($1)	($0)	($4)
Change in DSM	$63	$0	$1	$2	$2	$2	$3	$5	$5	$7	$7	$8	$8	$11	$12	$13	$13	$13	$13	$13	$13
Change in System Fixed Cost	$89	$0	($0)	($0)	$0	$0	$4	$4	$4	$4	$4	$4	($15)	($16)	$8	$56	$90	$31	$31	($23)	$60
Net (Benefit)/Cost	($22)	$12	$14	$13	$1	($2)	($1)	($1)	($1)	($3)	($2)	($3)	($25)	($24)	($19)	($8)	($2)	($9)	($11)	($17)	($14)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($151)	$1	$3	$2	($11)	($14)	($15)	($16)	($17)	($18)	($17)	($18)	($21)	($21)	($22)	($23)	($24)	($25)	($27)	($28)	($30)
Change in Emissions	($24)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($3)	($4)	($4)	($5)	($6)	($6)	($7)	($7)	($7)	($8)	($7)
Change in DSM	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)
Change in System Fixed Cost	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)
Net (Benefit)/Cost	($41)	$12	$13	$12	($0)	($3)	($3)	($4)	($5)	($6)	($7)	($9)	($12)	($13)	($14)	($15)	($16)	($18)	($19)	($21)	($22)

SO Model Annual Results ($ million)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($277)	$2	$4	$2	($14)	($19)	($21)	($22)	($24)	($25)	($25)	($26)	($29)	($29)	($31)	($18)	($33)	($89)	($82)	($133)	($81)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	$31	$0	($0)	($0)	($0)	$1	$2	$2	$2	$3	$3	$3	$3	$4	$5	$6	$6	$8	$9	$10	$10
Change in System Fixed Cost	$36	$0	($0)	($0)	$0	$0	$0	($0)	$0	$0	$0	$0	($1)	($5)	($6)	($19)	($7)	$9	($4)	$71	$99
Net (Benefit)/Cost	($75)	$12	$14	$13	($4)	($7)	($7)	($8)	($9)	($10)	($10)	($10)	($13)	($16)	($18)	($18)	($19)	($57)	($62)	($37)	$44

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($179)	$2	$4	$3	($14)	($17)	($17)	($18)	($19)	($19)	($20)	($20)	($34)	($28)	($30)	($32)	($55)	($7)	($10)	($73)	$8
Change in Emissions	$4	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($1)	($1)	($1)	($1)	($0)	($1)	$4	$5	$5	$8
Change in DSM	($70)	$0	$0	($1)	($2)	($3)	($4)	($4)	($5)	($6)	($6)	($7)	($9)	($9)	($12)	($14)	($15)	($17)	($18)	($19)	($22)
Change in System Fixed Cost	$46	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$14	$7	$10	$12	$40	$10	$15	$38	($22)
Net (Benefit)/Cost	($64)	$12	$14	$12	($5)	($9)	($9)	($10)	($12)	($14)	($14)	($15)	($16)	($17)	($19)	($20)	($16)	$6	$6	($35)	($13)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($199)	$2	$4	$2	($15)	($19)	($20)	($21)	($23)	($24)	($24)	($25)	($13)	($30)	($36)	($38)	($30)	($38)	($40)	($41)	($12)
Change in Emissions	($18)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($2)	$0	($4)	($3)	($2)	($5)	($5)	($4)	($5)	($21)
Change in DSM	$9	$0	$0	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Change in System Fixed Cost	($28)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($18)	$0	$4	$4	($2)	$2	$2	$2	($87)
Net (Benefit)/Cost	($103)	$12	$14	$13	($3)	($7)	($7)	($8)	($10)	($11)	($12)	($14)	($17)	($19)	($20)	($21)	($21)	($25)	($26)	($28)	($103)

PaR Stochastic-Mean Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($82)	$1	$2	$0	($6)	($9)	($10)	($10)	($12)	($11)	($9)	($10)	($12)	($15)	$13	$6	($13)	($27)	($22)	($22)	($21)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($12)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($0)	($9)	($9)	($9)	($0)	($0)	($0)	($0)
Change in DSM	($13)	$0	($0)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($1)	($1)	($1)	$0	$0	$0	($0)	($0)
Change in Deficiency	($1)	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$1	$1	($1)	($2)	$0	($1)
Change in System Fixed Cost	$17	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$4	$4	($35)	$15	$28	$20	$12	$3	$1
Net (Benefit)/Cost	$43	$11	$12	$10	$4	$1	$0	($1)	($2)	($1)	$1	($0)	$2	$1	($17)	$25	$21	$6	$2	($3)	($5)

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($222)	$1	$2	($1)	($9)	($12)	($13)	($13)	($16)	($15)	($13)	($12)	($15)	($45)	($53)	($51)	($49)	($56)	($58)	($62)	($64)
Change in Emissions	$5	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($2)	($6)	$2	$3	$4	$5	$5	$6	$6
Change in VOM	$9	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$8	$3	$3	$3	$3	$3	$2	$2
Change in DSM	$12	$0	$1	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$1	$1	$0	$0	$0	($2)	($2)
Change in Deficiency	($0)	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$1	$1	($0)	$0	($1)	$1	($2)
Change in System Fixed Cost	$71	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($3)	$37	$28	$19	$16	$25	$25	$25	$27
Net (Benefit)/Cost	$9	$11	$13	$11	$3	$1	$0	$0	($2)	($2)	$0	$1	($5)	$9	($4)	($9)	($12)	($8)	($12)	($14)	($18)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($123)	$1	$2	$0	($9)	($11)	($12)	($12)	($15)	($14)	($12)	($14)	($17)	($19)	($20)	($19)	($17)	($22)	($20)	($25)	($22)
Change in Emissions	($24)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($4)	($6)	($4)	($10)	($5)	($6)	($3)	($7)	($2)	($8)
Change in VOM	($2)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($1)
Change in DSM	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)
Change in Deficiency	($3)	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	$0	($0)	$0	($1)	($0)	($1)	($3)	($2)	($0)
Change in System Fixed Cost	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	($0)
Net (Benefit)/Cost	($17)	$11	$12	$11	$2	($0)	($1)	($1)	($3)	($3)	($3)	($5)	($10)	($10)	($16)	($11)	($9)	($12)	($15)	($14)	($15)

PaR Stochastic-Mean Results ($ million)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($176)	$1	$2	($0)	($8)	($11)	($13)	($14)	($17)	($16)	($13)	($15)	($61)	($32)	($23)	($24)	($51)	($25)	($25)	($28)	($28)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($2)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$4	($4)	($1)	($0)	($1)	($0)	($0)	($0)	($0)
Change in DSM	($2)	$0	($0)	($0)	$0	$0	$0	$0	$0	($0)	($1)	($1)	($1)	($0)	($0)	($0)	($0)	($0)	($0)	($2)	($2)
Change in Deficiency	$1	$0	$0	$0	($0)	$0	$0	$0	($0)	($0)	$0	$0	$0	$1	$1	$1	$0	($2)	$2	($1)	$1
Change in System Fixed Cost	$21	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$60	($32)	($23)	($19)	$63	$1	$1	$1	$2
Net (Benefit)/Cost	($24)	$11	$12	$10	$3	$0	($1)	($2)	($5)	($4)	($1)	($3)	$14	($54)	($32)	($28)	$25	($13)	($8)	($15)	($12)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($273)	$1	$2	($1)	($10)	($14)	($18)	($19)	($24)	($23)	($21)	($24)	($29)	($31)	($46)	($74)	($97)	($65)	($65)	($24)	($82)
Change in Emissions	($17)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($1)	($2)	($2)	($2)	($5)	($7)	($9)	($3)	($4)	($0)	($10)
Change in VOM	($14)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($1)	($9)	($9)	($10)	($1)	($1)	($0)	($3)
Change in DSM	$68	$0	$1	$2	$2	$2	$3	$5	$6	$7	$7	$8	$9	$11	$13	$14	$14	$14	$14	$14	$14
Change in Deficiency	$0	$0	$0	$0	$0	($0)	$0	($0)	$0	$0	$0	($0)	$0	$1	$1	$1	($0)	($2)	($1)	$0	($1)
Change in System Fixed Cost	$89	$0	($0)	($0)	$0	$0	$4	$4	$4	$4	$4	$4	($15)	($16)	$8	$56	$90	$31	$31	($23)	$60
Net (Benefit)/Cost	($13)	$10	$13	$11	$3	($0)	$1	$1	($2)	($1)	$2	$0	($24)	($23)	($24)	($6)	$1	($10)	($10)	($18)	($5)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($142)	$1	$2	$0	($9)	($13)	($14)	($14)	($18)	($16)	($14)	($16)	($18)	($23)	($23)	($22)	($21)	($24)	($23)	($29)	($27)
Change in Emissions	($23)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($4)	($6)	($2)	($10)	($5)	($6)	($5)	($8)	($4)	($5)
Change in VOM	($1)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Change in DSM	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)
Change in Deficiency	($2)	($0)	$0	($0)	($0)	$0	$0	($0)	$0	$0	$0	$0	($0)	$0	$0	($0)	($0)	($2)	($1)	($1)	($1)
Change in System Fixed Cost	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)
Net (Benefit)/Cost	($35)	$11	$12	$11	$2	($1)	($2)	($3)	($6)	($5)	($4)	($7)	($11)	($12)	($19)	($13)	($12)	($17)	($17)	($19)	($19)

PaR Stochastic-Mean Results ($ million)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($236)	$1	$2	$0	($11)	($16)	($19)	($19)	($23)	($22)	($19)	($22)	($22)	($27)	($32)	($15)	($27)	($74)	($64)	($111)	($63)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($6)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($5)	($5)	($6)	($1)
Change in DSM	$33	$0	($0)	($0)	($0)	$1	$2	$3	$2	$3	$3	$3	$4	$5	$5	$6	$7	$8	$10	$11	$11
Change in Deficiency	($1)	($0)	($0)	($0)	$0	$0	($0)	$0	($0)	$0	($0)	($0)	$0	($0)	$0	$1	$0	($2)	$2	($1)	($3)
Change in System Fixed Cost	$36	$0	($0)	($0)	$0	$0	$0	($0)	$0	$0	$0	$0	($1)	($5)	($6)	($19)	($7)	$9	($4)	$71	$99
Net (Benefit)/Cost	($40)	$11	$13	$10	($1)	($4)	($5)	($5)	($9)	($6)	($4)	($6)	($6)	($14)	($18)	($14)	($13)	($49)	($47)	($21)	$59

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($154)	$1	$2	$0	($11)	($14)	($16)	($16)	($19)	($17)	($14)	($16)	($31)	($25)	($32)	($27)	($44)	($8)	($8)	($55)	$18
Change in Emissions	$5	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($0)	($1)	$6	$5	$3	$10
Change in VOM	$6	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$5	$5	$4	$6
Change in DSM	($74)	$0	$0	($1)	($2)	($4)	($4)	($4)	($5)	($7)	($7)	($8)	($9)	($10)	($12)	($14)	($16)	($18)	($19)	($20)	($23)
Change in Deficiency	$3	($0)	($0)	($0)	$0	$0	($0)	($0)	($0)	$0	($0)	($0)	($0)	$0	$0	$1	$0	$1	$2	$6	$3
Change in System Fixed Cost	$46	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$14	$7	$10	$12	$40	$10	$15	$38	($22)
Net (Benefit)/Cost	($34)	$11	$13	$10	($2)	($6)	($8)	($8)	($13)	($12)	($9)	($12)	($14)	($15)	($21)	($16)	($6)	$11	$16	($9)	$7

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Project	$134	$10	$10	$10	$11	$11	$12	$12	$12	$12	$13	$13	$13	$13	$14	$14	$14	$15	$15	$15	$16
Change in NPC	($175)	$1	$2	$0	($12)	($16)	($18)	($18)	($22)	($21)	($18)	($20)	($13)	($26)	($37)	($30)	($24)	($29)	($31)	($32)	($21)
Change in Emissions	($18)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($4)	($0)	($6)	($6)	($5)	($3)	($3)	($5)	($6)	($7)
Change in VOM	($2)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($3)
Change in DSM	$9	$0	$0	$0	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Change in Deficiency	($1)	$0	($0)	($0)	$0	$0	($0)	$0	($1)	$0	$0	($0)	($0)	($0)	($0)	($0)	($1)	($2)	$0	$1	$1
Change in System Fixed Cost	($28)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($18)	$0	$4	$4	($2)	$2	$2	$2	($87)
Net (Benefit)/Cost	($80)	$11	$13	$11	$0	($4)	($6)	($5)	($10)	($9)	($7)	($10)	($16)	($18)	($24)	($16)	($15)	($17)	($17)	($19)	($100)

ATTACHMENT C – ANNUAL REVENUE REQUIREMENT PRICE-POLICY DETAIL FOR WIND REPOWERING

Estimated Annual Revenue Requirement Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts																																			
NPC	($260)	$1	$2	$0	($6)	($9)	($10)	($10)	($12)	($11)	($9)	($10)	($12)	($15)	$13	$6	($13)	($27)	($22)	($22)	($21)	($25)	($39)	($73)	($76)	($86)	($87)	($89)	($91)	($93)	($95)	($98)	($91)	($61)	($10)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($89)	$0	($0)	($1)	($1)	($2)	($2)	($3)	($3)	($3)	($3)	($3)	($3)	($1)	($10)	($10)	($9)	($1)	($2)	$0	($1)	($9)	($14)	($26)	($27)	($30)	($31)	($32)	($33)	($33)	($34)	($35)	($32)	($22)	($3)
System Fixed Costs	$108	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$4	$4	($35)	$15	$28	$20	$12	$3	$1	$13	$20	$38	$39	$44	$45	$46	$47	$48	$49	$50	$47	$32	$5
Net System Impacts	($241)	$1	$2	($0)	($7)	($11)	($11)	($12)	($15)	($13)	($11)	($13)	($11)	($13)	($31)	$11	$6	($8)	($13)	($18)	($21)	($21)	($32)	($62)	($64)	($72)	($74)	($75)	($77)	($79)	($80)	($82)	($77)	($52)	($8)
Net (Benefit)/Cost	($41)	$2	$3	($2)	$4	($18)	($34)	($49)	($57)	($67)	($74)	($79)	($90)	($60)	$22	$82	$72	$52	$50	$32	$24	$36	$43	$46	$52	$50	$54	$53	$52	$53	$53	$58	$70	$56	$5

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts																																			
NPC	($935)	$1	$2	($1)	($9)	($12)	($13)	($13)	($16)	($15)	($13)	($12)	($15)	($45)	($53)	($51)	($49)	($56)	($58)	($62)	($64)	($100)	($155)	($293)	($305)	($343)	($350)	($358)	($366)	($374)	($382)	($391)	($365)	($246)	($38)
Emissions	$36	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($2)	($6)	$2	$3	$4	$5	$5	$6	$6	$4	$7	$13	$13	$15	$15	$16	$16	$16	$17	$17	$16	$11	$2
Other Variable Costs	$71	$0	$1	$1	$2	$2	$1	$2	$2	$2	$2	$2	$1	$9	$6	$6	$3	$3	$1	$1	($2)	$7	$11	$20	$21	$24	$24	$25	$26	$26	$27	$27	$25	$17	$3
System Fixed Costs	$383	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($3)	$37	$28	$19	$16	$25	$25	$25	$27	$44	$68	$128	$134	$150	$153	$157	$160	$164	$168	$171	$160	$108	$17
Net System Impacts	($445)	$1	$2	$1	($8)	($11)	($12)	($12)	($14)	($14)	($12)	($12)	($18)	($5)	($18)	($23)	($26)	($23)	($27)	($30)	($34)	($45)	($69)	($131)	($137)	($154)	($157)	($161)	($164)	($168)	($171)	($175)	($164)	($110)	($17)
Net (Benefit)/Cost	($245)	$2	$4	($1)	$4	($18)	($34)	($48)	($57)	($68)	($75)	($77)	($96)	($52)	$35	$48	$40	$37	$36	$21	$11	$12	$7	($24)	($21)	($31)	($30)	($32)	($35)	($36)	($38)	($35)	($17)	($3)	($4)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts																																			
NPC	($414)	$1	$2	$0	($9)	($11)	($12)	($12)	($15)	($14)	($12)	($14)	($17)	($19)	($20)	($19)	($17)	($22)	($20)	($25)	($22)	($41)	($63)	($119)	($125)	($140)	($143)	($146)	($149)	($153)	($156)	($159)	($149)	($100)	($16)
Emissions	($109)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($4)	($6)	($4)	($10)	($5)	($6)	($3)	($7)	($2)	($8)	($12)	($18)	($35)	($36)	($41)	($42)	($43)	($44)	($45)	($46)	($47)	($44)	($29)	($5)
Other Variable Costs	($21)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	$0	($2)	($1)	($2)	($4)	($2)	($1)	($2)	($4)	($7)	($7)	($8)	($8)	($8)	($8)	($9)	($9)	($9)	($8)	($6)	($1)
System Fixed Costs	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Net System Impacts	($544)	$1	$2	$0	($9)	($11)	($12)	($12)	($15)	($16)	($15)	($18)	($23)	($23)	($30)	($25)	($24)	($27)	($30)	($30)	($31)	($55)	($85)	($161)	($168)	($189)	($193)	($197)	($201)	($206)	($210)	($215)	($201)	($136)	($21)
Net (Benefit)/Cost	($344)	$2	$3	($1)	$3	($19)	($34)	($49)	($58)	($69)	($77)	($84)	($102)	($71)	$23	$46	$42	$33	$33	$21	$13	$2	($9)	($53)	($52)	($66)	($65)	($69)	($72)	($74)	($77)	($75)	($54)	($28)	($8)

Estimated Annual Revenue Requirement Results ($ million)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts																																			
NPC	($689)	$1	$2	($0)	($8)	($11)	($13)	($14)	($17)	($16)	($13)	($15)	($61)	($32)	($23)	($24)	($51)	($25)	($25)	($28)	($28)	($72)	($111)	($210)	($219)	($246)	($251)	($257)	($263)	($269)	($275)	($281)	($262)	($177)	($28)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($13)	$0	($0)	($0)	$0	$0	$0	$0	$0	($0)	($1)	($1)	$3	($4)	$0	$1	($1)	($2)	$1	($4)	($2)	($1)	($2)	($4)	($4)	($5)	($5)	($5)	($5)	($5)	($6)	($6)	($5)	($4)	($1)
System Fixed Costs	$140	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$60	($32)	($23)	($19)	$63	$1	$1	$1	$2	$17	$26	$49	$51	$57	$58	$59	$61	$62	$63	$65	$61	$41	$6
Net System Impacts	($562)	$1	$2	($0)	($8)	($11)	($13)	($14)	($17)	($16)	($14)	($16)	$1	($67)	($46)	($42)	$10	($27)	($23)	($30)	($28)	($57)	($88)	($166)	($173)	($194)	($198)	($203)	($207)	($212)	($217)	($221)	($207)	($139)	($22)
Net (Benefit)/Cost	($362)	$2	$3	($2)	$3	($19)	($35)	($50)	($60)	($70)	($76)	($81)	($77)	($115)	$7	$29	$76	$33	$40	$20	$16	$0	($12)	($58)	($57)	($72)	($71)	($75)	($78)	($81)	($83)	($81)	($60)	($32)	($8)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts																																			
NPC	($1,101)	$1	$2	($1)	($10)	($14)	($18)	($19)	($24)	($23)	($21)	($24)	($29)	($31)	($46)	($74)	($97)	($65)	($65)	($24)	($82)	($116)	($179)	($340)	($354)	($398)	($406)	($415)	($425)	($434)	($444)	($454)	($423)	($286)	($44)
Emissions	($84)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($1)	($2)	($2)	($2)	($5)	($7)	($9)	($3)	($4)	($0)	($10)	($9)	($14)	($27)	($28)	($32)	($33)	($33)	($34)	($35)	($36)	($36)	($34)	($23)	($4)
Other Variable Costs	$186	$0	$1	$2	$2	$2	$3	$5	$6	$7	$7	$8	$9	$11	$4	$6	$4	$12	$12	$14	$11	$19	$29	$54	$56	$63	$65	$66	$68	$69	$71	$72	$67	$45	$7
System Fixed Costs	$439	$0	($0)	($0)	$0	$0	$4	$4	$4	$4	$4	$4	($15)	($16)	$8	$56	$90	$31	$31	($23)	$60	$49	$76	$144	$150	$168	$172	$176	$180	$184	$188	$192	$179	$121	$19
Net System Impacts	($559)	$1	$2	$1	($8)	($11)	($11)	($11)	($14)	($14)	($11)	($13)	($37)	($37)	($38)	($20)	($13)	($25)	($25)	($33)	($21)	($58)	($89)	($169)	($177)	($198)	($203)	($207)	($212)	($216)	($221)	($226)	($211)	($142)	($22)
Net (Benefit)/Cost	($359)	$2	$4	($1)	$3	($19)	($33)	($47)	($57)	($67)	($73)	($78)	($115)	($84)	$15	$51	$53	$35	$38	$17	$24	($1)	($14)	($62)	($61)	($76)	($75)	($79)	($82)	($85)	($87)	($85)	($64)	($35)	($9)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts																																			
NPC	($480)	$1	$2	$0	($9)	($13)	($14)	($14)	($18)	($16)	($14)	($16)	($18)	($23)	($23)	($22)	($21)	($24)	($23)	($29)	($27)	($47)	($73)	($139)	($144)	($162)	($166)	($169)	($173)	($177)	($181)	($185)	($173)	($116)	($18)
Emissions	($107)	$0	$0	$0	$0	$0	$0	$0	$0	($2)	($3)	($4)	($6)	($2)	($10)	($5)	($6)	($5)	($8)	($4)	($5)	($12)	($18)	($34)	($36)	($40)	($41)	($42)	($43)	($44)	($45)	($46)	($43)	($29)	($5)
Other Variable Costs	($15)	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)	($1)	($2)	($1)	($1)	($2)	($2)	($3)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($4)	($1)
System Fixed Costs	($0)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Net System Impacts	($602)	$1	$2	$0	($9)	($13)	($14)	($15)	($18)	($18)	($16)	($20)	($24)	($26)	($33)	($28)	($27)	($32)	($32)	($34)	($34)	($61)	($94)	($178)	($185)	($208)	($213)	($217)	($222)	($227)	($232)	($237)	($222)	($150)	($23)
Net (Benefit)/Cost	($401)	$2	$3	($1)	$2	($20)	($36)	($51)	($61)	($71)	($79)	($86)	($103)	($73)	$20	$44	$39	$29	$31	$16	$10	($4)	($18)	($70)	($70)	($86)	($85)	($89)	($93)	($96)	($99)	($97)	($75)	($42)	($10)

Estimated Annual Revenue Requirement Results ($ million)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Project Net Costs																		
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60
System Impacts																		
NPC	($895)	$1	$2	$0	($11)	($16)	($19)	($19)	($23)	($22)	($19)	($22)	($22)	($27)	($32)	($15)	($27)	($74)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	$99	($0)	($0)	($0)	($0)	$1	$2	$3	$2	$3	$3	$3	$3	$4	$6	$7	$7	$1
System Fixed Costs	$196	$0	($0)	($0)	$0	$0	$0	($0)	$0	$0	$0	$0	($1)	($5)	($6)	($19)	($7)	$9
Net System Impacts	($600)	$1	$2	($0)	($12)	($15)	($17)	($16)	($21)	($19)	($16)	($19)	($19)	($27)	($32)	($28)	($27)	($63)
Net (Benefit)/Cost	($400)	$3	$4	($2)	($0)	($23)	($39)	($53)	($64)	($72)	($78)	($84)	($97)	($75)	$21	$44	$39	($3)

(Benefit)/Cost	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																	
Capital Recovery	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts																	
NPC	($64)	($111)	($63)	($93)	($143)	($270)	($282)	($316)	($323)	($330)	($338)	($345)	($353)	($361)	($337)	($227)	($35)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	$7	$4	$7	$10	$16	$30	$31	$35	$36	$37	$38	$38	$39	$40	$37	$25	$4
System Fixed Costs	($4)	$71	$99	$22	$35	$66	$68	$77	$78	$80	$82	$84	$86	$87	$82	$55	$9
Net System Impacts	($62)	($37)	$43	($60)	($92)	($175)	($182)	($204)	($209)	($214)	($218)	($223)	($228)	($233)	($218)	($147)	($23)
Net (Benefit)/Cost	$1	$14	$88	($3)	($16)	($67)	($66)	($82)	($82)	($86)	($89)	($92)	($95)	($93)	($71)	($39)	($9)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Project Net Costs																		
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60
System Impacts																		
NPC	($517)	$1	$2	$0	($11)	($14)	($16)	($16)	($19)	($17)	($14)	($16)	($31)	($25)	($32)	($27)	($44)	($8)
Emissions	$30	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($0)	($1)	$6
Other Variable Costs	($245)	($0)	$0	($1)	($2)	($4)	($4)	($4)	($6)	($7)	($7)	($8)	($10)	($10)	($12)	($14)	($16)	($12)
System Fixed Costs	$258	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	$14	$7	$10	$12	$40	$10
Net System Impacts	($474)	$1	$2	($1)	($13)	($18)	($20)	($20)	($25)	($24)	($22)	($25)	($28)	($29)	($35)	($30)	($21)	($4)
Net (Benefit)/Cost	($274)	$3	$4	($2)	($2)	($25)	($42)	($56)	($68)	($78)	($84)	($91)	($106)	($76)	$18	$42	$45	$56

(Benefit)/Cost	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																	
Capital Recovery	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts																	
NPC	($8)	($55)	$18	($51)	($79)	($149)	($155)	($174)	($178)	($182)	($186)	($190)	($194)	($199)	($186)	($125)	($19)
Emissions	$5	$3	$10	$4	$5	$10	$11	$12	$12	$13	$13	$13	$14	$14	$13	$9	$1
Other Variable Costs	($12)	($10)	($14)	($25)	($39)	($74)	($77)	($86)	($88)	($90)	($92)	($94)	($96)	($98)	($92)	($62)	($10)
System Fixed Costs	$15	$38	($22)	$30	$46	$87	$91	$102	$104	$106	$109	$111	$113	$116	$108	$73	$11
Net System Impacts	$1	($25)	($8)	($43)	($66)	($125)	($131)	($147)	($150)	($153)	($157)	($160)	($164)	($167)	($156)	($105)	($16)
Net (Benefit)/Cost	$64	$26	$36	$14	$10	($18)	($15)	($24)	($23)	($25)	($27)	($29)	($30)	($27)	($10)	$2	($3)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	PVRR(d)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Project Net Costs																		
Capital Recovery	$936	($1)	($2)	$21	$116	$120	$109	$100	$92	$87	$84	$81	$78	$75	$72	$70	$65	$59
O&M	$81	$0	$0	$1	$4	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
Wind Tax	$6	($0)	($0)	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PTCs	($822)	$2	$4	($23)	($109)	($132)	($132)	($137)	($137)	($142)	($147)	($147)	($157)	($123)	($20)	$0	$0	$0
Net Project Cost	$200	$1	$1	($1)	$11	($8)	($22)	($36)	($43)	($54)	($62)	($65)	($78)	($47)	$53	$72	$66	$60
System Impacts																		
NPC	($565)	$1	$2	$0	($12)	($16)	($18)	($18)	($22)	($21)	($18)	($20)	($13)	($26)	($37)	($30)	($24)	($29)
Emissions	($82)	$0	$0	$0	$0	$0	$0	$0	$0	($1)	($2)	($4)	($0)	($6)	($6)	($5)	($3)	($3)
Other Variable Costs	$14	$0	$0	($0)	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$0	($1)
System Fixed Costs	($156)	$0	($0)	($0)	$0	($0)	$0	($0)	$0	$0	$0	$0	($18)	$0	$4	$4	($2)	$2
Net System Impacts	($789)	$1	$2	$0	($11)	($15)	($17)	($17)	($22)	($21)	($19)	($23)	($30)	($31)	($38)	($30)	($29)	($31)
Net (Benefit)/Cost	($589)	$3	$4	($1)	$0	($23)	($39)	($53)	($65)	($75)	($81)	($89)	($108)	($79)	$15	$42	$37	$29

(Benefit)/Cost	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																	
Capital Recovery	$62	$49	$42	$51	$62	$78	$85	$88	$92	$92	$93	$94	$96	$102	$107	$77	$11
O&M	$1	$1	$2	$5	$14	$28	$29	$32	$33	$34	$34	$35	$36	$37	$38	$30	$3
Wind Tax	$0	$0	$0	$0	$1	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$1	$0
PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$63	$50	$44	$57	$76	$108	$116	$122	$127	$128	$129	$131	$134	$141	$147	$108	$14
System Impacts																	
NPC	($31)	($32)	($21)	($55)	($84)	($160)	($167)	($187)	($191)	($196)	($200)	($204)	($209)	($214)	($199)	($135)	($21)
Emissions	($5)	($6)	($7)	($9)	($14)	($26)	($27)	($31)	($31)	($32)	($33)	($33)	($34)	($35)	($33)	($22)	($3)
Other Variable Costs	$1	$1	($1)	$1	$1	$3	$3	$3	$3	$3	$3	$4	$4	$4	$3	$2	$0
System Fixed Costs	$2	$2	($87)	($18)	($28)	($52)	($55)	($61)	($63)	($64)	($66)	($67)	($69)	($70)	($65)	($44)	($7)
Net System Impacts	($32)	($35)	($116)	($81)	($124)	($236)	($246)	($276)	($282)	($288)	($295)	($301)	($308)	($315)	($294)	($198)	($31)
Net (Benefit)/Cost	$31	$16	($71)	($24)	($49)	($128)	($130)	($154)	($155)	($160)	($165)	($170)	($174)	($174)	($147)	($91)	($17)

ATTACHMENT D – SYSTEM MODELING PRICE-POLICY DETAIL FOR NEW WIND AND TRANSMISSION

SO Model Annual Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($311)	$0	$0	$1	($14)	($48)	($49)	($51)	($48)	($48)	($46)	($47)	($40)	($42)	($25)	($20)	($22)	($29)	($28)	($27)	($22)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	($70)	$0	($0)	($1)	($2)	($4)	($6)	($7)	($8)	($9)	($9)	($10)	($12)	($10)	($10)	($11)	($11)	($11)	($11)	($11)	($11)
Change in System Fixed Cost	($672)	$0	$0	$0	($0)	($31)	($57)	($59)	($64)	($67)	($68)	($70)	($87)	($90)	($132)	($116)	($150)	($159)	($167)	($143)	($153)
Net (Benefit)/Cost	$121	$0	$0	($0)	$0	$20	$17	$16	$19	$20	$24	$23	$28	$30	$5	$33	$1	($13)	($19)	$8	$11

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($511)	$0	$0	$0	($16)	($49)	($52)	($55)	($52)	($54)	($53)	($54)	($49)	($53)	($69)	($64)	($70)	($100)	($106)	($158)	($136)
Change in Emissions	($29)	$0	$0	$0	$0	$0	$0	$0	$0	($4)	($5)	($5)	($5)	($9)	($2)	($1)	($2)	($5)	($9)	($13)	($16)
Change in DSM	($26)	$0	($0)	($0)	($0)	($1)	($2)	($2)	($2)	($2)	($2)	($4)	($4)	($4)	($4)	($6)	($6)	($6)	($6)	($6)	($6)
Change in System Fixed Cost	($536)	$0	$0	$0	($0)	($31)	($57)	($59)	($64)	($67)	($68)	($70)	($88)	($88)	($98)	($90)	($115)	($90)	($89)	($61)	($59)
Net (Benefit)/Cost	$73	$0	$0	$0	$1	$21	$19	$18	$22	$17	$19	$18	$21	$17	($1)	$19	($8)	($14)	($23)	($48)	($19)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($361)	$0	$0	$0	($16)	($52)	($55)	($57)	($51)	($56)	($54)	($44)	($17)	($16)	($26)	($35)	($60)	($9)	($24)	($87)	($101)
Change in Emissions	($239)	$0	$0	$0	$0	$0	$0	$0	$0	($4)	($12)	($33)	($56)	($64)	($71)	($88)	($95)	($39)	($60)	($40)	($65)
Change in DSM	($6)	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($3)
Change in System Fixed Cost	($651)	$0	$0	$0	($0)	($31)	($57)	($59)	($64)	($67)	($68)	($70)	($102)	($105)	($125)	($99)	($88)	($188)	($161)	($179)	($77)
Net (Benefit)/Cost	($84)	$0	$0	$0	$1	$20	$17	$17	$23	$17	$11	$2	($10)	($15)	($50)	($42)	($58)	($50)	($59)	($117)	($48)

SO Model Annual Results ($ million)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($492)	$0	$0	$0	($17)	($57)	($62)	($64)	($65)	($64)	($61)	($63)	($57)	($81)	($56)	($74)	($106)	($67)	($75)	$29	($95)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	$16	$0	$0	$0	$1	$1	$1	$2	$2	$2	$2	$2	$2	$2	$3	$3	$3	$3	$3	$1	$4
Change in System Fixed Cost	($717)	$0	$0	$0	($0)	($31)	($57)	($59)	($64)	($67)	($68)	($70)	($107)	($120)	($173)	($122)	($80)	($143)	($142)	($266)	($172)
Net (Benefit)/Cost	($19)	$0	$0	$0	$1	$15	$12	$12	$13	$15	$20	$20	$5	($27)	($54)	($13)	$1	($20)	($27)	($46)	($66)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($615)	$0	$0	$0	($16)	($56)	($64)	($67)	($67)	($65)	($62)	($65)	($58)	($73)	($56)	($105)	($138)	($137)	($149)	($148)	($82)
Change in Emissions	($46)	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($10)	($11)	($10)	($7)	($8)	($11)	($13)	($8)	($8)	($9)	($8)
Change in DSM	$27	$0	$0	$0	$0	$0	$0	$2	$2	$2	$2	$3	$3	$5	$6	$7	$7	$7	$7	$7	$7
Change in System Fixed Cost	($626)	$0	$0	$0	($0)	($31)	($57)	($60)	($64)	($67)	($68)	($71)	($107)	($110)	($178)	($120)	($54)	($92)	($91)	($99)	($184)
Net (Benefit)/Cost	($85)	$0	$0	$0	$1	$16	$9	$9	$10	$5	$9	$7	($5)	($14)	($64)	($48)	($14)	($43)	($54)	($60)	($69)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($454)	$0	$0	$1	($16)	($55)	($62)	($64)	($64)	($62)	($60)	($68)	($48)	($66)	($35)	($24)	($33)	($97)	($107)	($26)	($67)
Change in Emissions	($208)	$0	$0	$0	$0	$0	$0	$0	$0	($11)	($22)	($23)	($38)	($50)	($48)	($60)	($55)	($43)	($48)	($80)	($82)
Change in DSM	($40)	$0	$0	($1)	($1)	($2)	($2)	($3)	($3)	($4)	($4)	($4)	($5)	($5)	($6)	($7)	($8)	($9)	($11)	($13)	($16)
Change in System Fixed Cost	($628)	$0	$0	$0	($0)	($31)	($57)	($59)	($64)	($67)	($68)	($70)	($90)	($85)	($131)	($137)	($139)	($133)	($131)	($102)	($99)
Net (Benefit)/Cost	($156)	$0	$0	($0)	$0	$15	$8	$7	$9	($0)	($6)	($14)	($15)	($34)	($47)	($47)	($50)	($96)	($109)	($31)	($65)

SO Model Annual Results ($ million)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($775)	$0	$0	$0	($22)	($74)	($91)	($87)	($94)	($92)	($88)	($91)	($89)	$21	($123)	($104)	($129)	($198)	($202)	($132)	($168)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in DSM	$13	$0	($0)	($0)	($0)	$1	$1	$1	$1	$1	$1	$1	$0	$1	$2	$2	$2	$4	$5	$7	$7
Change in System Fixed Cost	($716)	$0	$0	$0	($0)	($31)	($57)	($67)	($71)	($74)	($76)	($78)	($94)	($226)	($104)	($132)	($115)	($115)	($127)	($167)	($149)
Net (Benefit)/Cost	($304)	$0	$0	$0	($6)	($2)	($18)	($19)	($25)	($22)	($16)	($17)	($15)	($32)	($53)	($53)	($57)	($122)	($137)	($101)	($113)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($804)	$0	$0	$1	($21)	($72)	($88)	($90)	($97)	($94)	($90)	($92)	($90)	($102)	($129)	($86)	($166)	($121)	($143)	($156)	($170)
Change in Emissions	($31)	$0	$0	$0	$0	$0	$0	$0	$0	($4)	($5)	($6)	($5)	($6)	($7)	($4)	($10)	($8)	($9)	($7)	($10)
Change in DSM	($61)	$0	($0)	($1)	($2)	($4)	($4)	($4)	($5)	($6)	($6)	($7)	($8)	($9)	($10)	($12)	($13)	($13)	($13)	($13)	($13)
Change in System Fixed Cost	($597)	$0	$0	$0	($0)	($31)	($57)	($59)	($64)	($67)	($68)	($70)	($87)	($86)	($88)	($145)	($56)	($138)	($127)	($125)	($126)
Net (Benefit)/Cost	($318)	$0	$0	($0)	($7)	($4)	($20)	($20)	($26)	($27)	($22)	($25)	($23)	($31)	($61)	($66)	($61)	($93)	($105)	($111)	($121)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($605)	$0	$0	$0	($23)	($76)	($92)	($93)	($98)	($97)	($93)	($85)	$7	($87)	($78)	($49)	($78)	($63)	($60)	($58)	($117)
Change in Emissions	($122)	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($11)	($28)	($11)	($41)	($35)	($33)	($37)	($28)	($23)	($31)	($36)
Change in DSM	($18)	$0	$0	($0)	($0)	($0)	($0)	($0)	($2)	($2)	($2)	($3)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)
Change in System Fixed Cost	($826)	$0	$0	$0	($0)	($31)	($57)	($59)	($64)	($67)	($68)	($70)	($197)	($88)	($126)	($188)	($141)	($196)	($214)	($219)	($264)
Net (Benefit)/Cost	($396)	$0	$0	$0	($6)	($4)	($20)	($20)	($24)	($27)	($27)	($35)	($37)	($48)	($70)	($94)	($75)	($105)	($115)	($122)	($223)

PaR Stochastic-Mean Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($340)	$0	$0	$1	($15)	($54)	($55)	($54)	($50)	($53)	($50)	($51)	($44)	($44)	($22)	($18)	($19)	($38)	($36)	($32)	($31)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($19)	$0	$0	$0	($0)	($1)	($1)	($1)	($2)	($2)	($2)	($2)	($1)	($1)	($9)	($10)	($10)	($1)	($0)	($0)	($1)
Change in DSM	($76)	$0	($0)	($1)	($2)	($5)	($6)	($7)	($9)	($9)	($10)	($11)	($12)	($11)	($11)	($12)	($12)	($12)	($12)	($12)	($13)
Change in Deficiency	($2)	$0	$0	($0)	$0	$0	$0	($0)	$0	($0)	$0	$0	($0)	($0)	($0)	($1)	$0	$0	($3)	($1)	($2)
Change in System Fixed Cost	($660)	$0	$0	$0	($0)	($31)	($56)	($58)	($63)	($65)	($66)	($69)	($85)	($87)	($130)	($114)	($147)	($157)	($165)	($141)	($151)
Net (Benefit)/Cost	$77	$0	($0)	($1)	($1)	$12	$11	$12	$17	$15	$19	$19	$25	$28	($0)	$26	($4)	($21)	($30)	$3	$1

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($536)	$0	$0	$0	($17)	($57)	($58)	($57)	($53)	($60)	($57)	($58)	($51)	($54)	($66)	($64)	($67)	($103)	($112)	($156)	($144)
Change in Emissions	($40)	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($6)	($7)	($10)	($11)	($2)	($2)	($4)	($9)	($11)	($19)	($22)
Change in VOM	($15)	$0	$0	$0	($0)	($1)	($1)	($1)	($2)	($1)	($1)	($1)	($1)	($2)	($7)	($6)	($7)	$1	$0	($1)	($1)
Change in DSM	($28)	$0	($0)	($0)	($0)	($2)	($2)	($2)	($2)	($2)	($3)	($4)	($4)	($4)	($5)	($6)	($6)	($6)	($6)	($6)	($7)
Change in Deficiency	($0)	$0	$0	$0	$0	$0	($0)	($0)	$0	($0)	$0	($0)	($0)	($0)	$0	$0	$1	$0	$1	($0)	($3)
Change in System Fixed Cost	($523)	$0	$0	$0	($0)	($31)	($55)	($58)	($63)	($65)	($66)	($69)	($85)	($86)	($95)	($87)	($113)	($88)	($87)	($58)	($57)
Net (Benefit)/Cost	$32	$0	($0)	($0)	($0)	$13	$13	$15	$20	$10	$13	$11	$15	$14	($3)	$15	($12)	($18)	($27)	($50)	($35)

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($446)	$0	$0	$0	($17)	($57)	($58)	($58)	($54)	($61)	($60)	($58)	($44)	($39)	($51)	($62)	($83)	($23)	($43)	($85)	($102)
Change in Emissions	($195)	$0	$0	$0	$0	$0	$0	$0	$0	($8)	($18)	($31)	($42)	($49)	($50)	($61)	($71)	($31)	($44)	($38)	($71)
Change in VOM	($18)	$0	$0	$0	($0)	($1)	($1)	($1)	($2)	($1)	($1)	($1)	($2)	($2)	($4)	($3)	($4)	($2)	($3)	($12)	($6)
Change in DSM	($7)	$0	$0	$0	$0	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($3)
Change in Deficiency	($3)	$0	$0	$0	$0	$0	($0)	($0)	$0	$0	$0	($0)	($0)	($0)	($0)	($2)	($1)	$0	($5)	$2	($2)
Change in System Fixed Cost	($638)	$0	$0	$0	($0)	($31)	($55)	($58)	($62)	($65)	($66)	($68)	($100)	($103)	($123)	($97)	($85)	($185)	($159)	($176)	($75)
Net (Benefit)/Cost	($133)	$0	$0	$0	($0)	$14	$13	$15	$21	$8	$1	($9)	($22)	($23)	($56)	($45)	($61)	($55)	($67)	($120)	($60)

PaR Stochastic-Mean Results ($ million)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($519)	$0	$0	($0)	($17)	($60)	($63)	($66)	($69)	($75)	($70)	($72)	($66)	($82)	($56)	($72)	($98)	($73)	($77)	$27	($94)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($25)	$0	$0	($0)	($0)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($1)	($5)	($9)	($10)	($11)	($2)	($2)	($0)	($3)
Change in DSM	$17	$0	$0	$0	$1	$1	$1	$2	$2	$2	$2	$2	$2	$2	$3	$3	$3	$3	$3	$2	$4
Change in Deficiency	$0	$0	$0	($0)	($0)	$0	$0	($0)	$0	$0	$0	$0	($0)	$1	$1	$0	$0	($1)	($1)	($0)	$1
Change in System Fixed Cost	($704)	$0	$0	$0	($0)	($31)	($55)	($58)	($63)	($65)	($66)	($69)	($104)	($117)	($171)	($120)	($78)	($140)	($140)	($264)	($170)
Net (Benefit)/Cost	($57)	$0	$0	$0	$0	$12	$10	$9	$9	$4	$10	$10	($3)	($30)	($60)	($17)	$1	($26)	($30)	($46)	($64)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($625)	$0	($0)	($0)	($18)	($63)	($67)	($69)	($69)	($74)	($69)	($71)	($66)	($72)	($54)	($99)	($132)	($135)	($143)	($135)	($66)
Change in Emissions	($51)	$0	$0	$0	$0	$0	$0	$0	$0	($6)	($7)	($8)	($9)	($8)	($9)	($12)	($16)	($13)	($15)	($17)	($14)
Change in VOM	($27)	$0	$0	($0)	($0)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($1)	($2)	($10)	($10)	($11)	($3)	($4)	($4)	($3)
Change in DSM	$29	$0	$0	$0	$0	$0	$0	$2	$2	$2	$2	$3	$4	$5	$6	$7	$7	$7	$7	$7	$8
Change in Deficiency	$1	$0	$0	($0)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	$1	$0
Change in System Fixed Cost	($613)	$0	$0	$0	($0)	($31)	($56)	($58)	($63)	($65)	($67)	($69)	($105)	($108)	($175)	($117)	($52)	($89)	($88)	($97)	($182)
Net (Benefit)/Cost	($111)	$0	$0	$0	($1)	$8	$5	$6	$8	($2)	$4	$3	($11)	($14)	($69)	($51)	($18)	($47)	($56)	($53)	($59)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($495)	$0	$0	$0	($17)	($62)	($66)	($66)	($66)	($71)	($68)	($71)	($56)	($66)	($47)	($43)	($41)	($92)	($101)	($27)	($76)
Change in Emissions	($219)	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($18)	($28)	($43)	($60)	($50)	($51)	($60)	($53)	($58)	($85)	($78)
Change in VOM	($21)	$0	$0	$0	($0)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($10)	($10)	($3)	($3)
Change in DSM	($43)	$0	$0	($1)	($1)	($2)	($2)	($3)	($3)	($4)	($4)	($4)	($5)	($6)	($6)	($7)	($8)	($9)	($11)	($14)	($17)
Change in Deficiency	($5)	$0	$0	($0)	$0	$0	$0	$0	($0)	$0	$0	$0	($0)	$0	$0	($1)	($1)	($3)	($3)	($8)	($2)
Change in System Fixed Cost	($615)	$0	$0	$0	($0)	($31)	($55)	($58)	($63)	($65)	($66)	($68)	($88)	($83)	($129)	($134)	($137)	($131)	($129)	($100)	($97)
Net (Benefit)/Cost	($224)	$0	$0	($0)	($1)	$7	$4	$4	$5	($7)	($11)	($22)	($26)	($44)	($62)	($58)	($63)	($111)	($125)	($47)	($74)

PaR Stochastic-Mean Results ($ million)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($724)	$0	$0	$0	($22)	($78)	($88)	($83)	($82)	($89)	($84)	($87)	($80)	$2	($112)	($93)	($115)	($172)	($175)	($120)	($147)
Change in Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Change in VOM	($21)	$0	$0	($0)	($0)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($0)	($2)	($2)	($2)	($8)	($8)	($7)	($7)
Change in DSM	$13	$0	($0)	($0)	($0)	$1	$1	$1	$1	$1	$1	$1	$1	$2	$2	$2	$3	$4	$6	$7	$7
Change in Deficiency	$1	$0	$0	$0	$0	$0	$1	($0)	$0	$1	$0	$0	$0	$0	$1	$1	($0)	($1)	$2	($3)	($3)
Change in System Fixed Cost	($703)	$0	$0	$0	($0)	($31)	($55)	($65)	($70)	($73)	($74)	($76)	($92)	($224)	($101)	($130)	($113)	($112)	($125)	($164)	($147)
Net (Benefit)/Cost	($260)	$0	($0)	($0)	($6)	($6)	($15)	($16)	($14)	($18)	($12)	($14)	($6)	($49)	($41)	($41)	($43)	($102)	($113)	($97)	($98)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($740)	$0	$0	$0	($21)	($76)	($85)	($83)	($82)	($88)	($83)	($85)	($79)	($92)	($121)	($75)	($145)	($117)	($131)	($134)	($149)
Change in Emissions	($44)	$0	$0	$0	$0	$0	$0	$0	$0	($6)	($7)	($8)	($7)	($8)	($8)	($6)	($12)	($11)	($12)	($14)	($16)
Change in VOM	($15)	$0	$0	$0	($0)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)
Change in DSM	($65)	$0	($0)	($1)	($3)	($4)	($4)	($4)	($6)	($6)	($7)	($8)	($9)	($9)	($11)	($12)	($14)	($14)	($14)	($14)	($14)
Change in Deficiency	$2	$0	$0	$0	$0	$0	$0	($0)	$0	$1	$0	$1	$1	$1	$1	$0	$1	($1)	($1)	($0)	($1)
Change in System Fixed Cost	($584)	$0	$0	$0	($0)	($31)	($55)	($58)	($63)	($65)	($66)	($68)	($85)	($83)	($86)	($142)	($54)	($135)	($125)	($122)	($124)
Net (Benefit)/Cost	($272)	$0	($0)	($1)	($7)	($9)	($17)	($14)	($13)	($23)	($18)	($20)	($15)	($22)	($55)	($56)	($42)	($94)	($99)	($96)	($109)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Cost of Projects	$1,174	$0	$0	$0	$17	$103	$129	$133	$140	$144	$147	$151	$167	$171	$172	$181	$185	$186	$187	$190	$198
Change in NPC	($585)	$0	$0	$0	($22)	($78)	($87)	($85)	($84)	($91)	($87)	($91)	$3	($84)	($81)	($50)	($78)	($68)	($63)	($55)	($103)
Change in Emissions	($151)	$0	$0	$0	$0	$0	$0	$0	$0	($8)	($16)	($25)	($10)	($46)	($43)	($43)	($48)	($35)	($33)	($35)	($54)
Change in VOM	($14)	$0	$0	$0	($0)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($1)	($2)	($2)	($2)	($2)	($2)	($1)	($1)	($5)
Change in DSM	($19)	$0	$0	($0)	($0)	($0)	($0)	($0)	($2)	($2)	($2)	($3)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)	($4)
Change in Deficiency	($1)	$0	$0	$0	$0	$0	$0	($0)	$0	$1	$0	$0	$0	$0	$0	($2)	($1)	($4)	($2)	($1)	$1
Change in System Fixed Cost	($813)	$0	$0	$0	($0)	($31)	($55)	($58)	($63)	($65)	($66)	($68)	($195)	($86)	($124)	($186)	($139)	($194)	($212)	($217)	($262)
Net (Benefit)/Cost	($409)	$0	$0	($0)	($6)	($7)	($16)	($12)	($11)	($24)	($27)	($38)	($38)	($50)	($81)	($106)	($88)	($119)	($130)	($123)	($229)

ATTACHMENT E – ANNUAL REVENUE REQUIREMENT PRICE-POLICY DETAIL FOR NEW WIND AND TRANSMISSION

Estimated Annual Revenue Requirement Results ($ million)

Low Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$681	$0	$0	$0	$12	$90	$87	$84	$81	$78	$76	$73	$71	$69	$66	$64	$61	$59	$57	$54	$53	$52	$51	$50	$49	$48	$47	$46	$45	$44	$44	$43	$42	$41	$40
Incremental Transmission Revenue	($82)	$0	$0	$0	($1)	($11)	($10)	($10)	($10)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
New Wind PPA	$318	$0	$0	$0	$0	$0	$24	$25	$26	$28	$29	$30	$44	$45	$44	$49	$50	$49	$47	$47	$52	$57	$58	$60	$61	$62	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Wind Capital Recovery	$1,360	$0	$0	$0	$29	$179	$164	$152	$143	$135	$132	$130	$128	$127	$126	$125	$123	$122	$121	$120	$119	$118	$117	$116	$115	$115	$115	$115	$115	$116	$118	$121	$127	$142	$91
New Wind O&M	$263	$0	$0	$0	$3	$19	$20	$20	$22	$22	$23	$23	$24	$24	$25	$26	$26	$27	$28	$28	$29	$30	$30	$31	$32	$33	$34	$35	$35	$36	$37	$38	$39	$40	$34
New Wind PTCs	($795)	$0	$0	$0	($29)	($131)	($131)	($136)	($142)	($141)	($146)	($146)	($152)	($151)	($121)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,745	$0	$0	$0	$14	$146	$152	$134	$120	$114	$104	$101	$106	$106	$132	$256	$254	$250	$245	$243	$246	$250	$250	$251	$252	$253	$190	$190	$190	$191	$193	$197	$203	$218	$160
System Impacts																																			
NPC	($426)	$0	$0	$1	($15)	($54)	($55)	($54)	($50)	($53)	($50)	($51)	($44)	($44)	($22)	($18)	($19)	($38)	($36)	($32)	($31)	($36)	($37)	($38)	($39)	($38)	($30)	($31)	($31)	($32)	($33)	($32)	($34)	($35)	($27)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($142)	$0	($0)	($1)	($3)	($5)	($8)	($9)	($11)	($11)	($12)	($12)	($14)	($12)	($21)	($23)	($22)	($13)	($16)	($14)	($15)	($19)	($19)	($20)	($20)	($20)	($16)	($16)	($16)	($17)	($17)	($17)	($18)	($18)	($14)
System Fixed Costs	($1,002)	$0	$0	$0	($0)	($31)	($56)	($58)	($63)	($65)	($66)	($69)	($85)	($87)	($130)	($114)	($147)	($157)	($165)	($141)	($151)	($143)	($146)	($151)	($153)	($151)	($120)	($122)	($124)	($128)	($131)	($127)	($137)	($139)	($107)
Net System Impacts	($1,571)	$0	($0)	($1)	($19)	($91)	($118)	($121)	($123)	($129)	($128)	($132)	($142)	($143)	($173)	($155)	($189)	($207)	($217)	($187)	($197)	($198)	($202)	($208)	($212)	($208)	($166)	($169)	($172)	($178)	($180)	($175)	($189)	($192)	($147)
Net (Benefit)/Cost	$174	$0	($0)	($1)	($4)	$55	$34	$13	($3)	($15)	($25)	($30)	($36)	($37)	($41)	$101	$65	$43	$28	$56	$49	$52	$48	$43	$39	$44	$24	$21	$18	$13	$13	$21	$14	$26	$12

Low Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$681	$0	$0	$0	$12	$90	$87	$84	$81	$78	$76	$73	$71	$69	$66	$64	$61	$59	$57	$54	$53	$52	$51	$50	$49	$48	$47	$46	$45	$44	$44	$43	$42	$41	$40
Incremental Transmission Revenue	($82)	$0	$0	$0	($1)	($11)	($10)	($10)	($10)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
New Wind PPA	$318	$0	$0	$0	$0	$0	$24	$25	$26	$28	$29	$30	$44	$45	$44	$49	$50	$49	$47	$47	$52	$57	$58	$60	$61	$62	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Wind Capital Recovery	$1,360	$0	$0	$0	$29	$179	$164	$152	$143	$135	$132	$130	$128	$127	$126	$125	$123	$122	$121	$120	$119	$118	$117	$116	$115	$115	$115	$115	$115	$116	$118	$121	$127	$142	$91
New Wind O&M	$263	$0	$0	$0	$3	$19	$20	$20	$22	$22	$23	$23	$24	$24	$25	$26	$26	$27	$28	$28	$29	$30	$30	$31	$32	$33	$34	$35	$35	$36	$37	$38	$39	$40	$34
New Wind PTCs	($795)	$0	$0	$0	($29)	($131)	($131)	($136)	($142)	($141)	($146)	($146)	($152)	($151)	($121)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,745	$0	$0	$0	$14	$146	$152	$134	$120	$114	$104	$101	$106	$106	$132	$256	$254	$250	$245	$243	$246	$250	$250	$251	$252	$253	$190	$190	$190	$191	$193	$197	$203	$218	$160
System Impacts																																			
NPC	($766)	$0	$0	$0	($17)	($57)	($58)	($57)	($53)	($60)	($57)	($58)	($51)	($54)	($66)	($64)	($67)	($103)	($112)	($156)	($144)	($96)	($98)	($101)	($103)	($101)	($81)	($82)	($84)	($86)	($88)	($85)	($92)	($94)	($72)
Emissions	($65)	$0	$0	$0	$0	$0	$0	$0	$0	($5)	($6)	($7)	($10)	($11)	($2)	($2)	($4)	($9)	($11)	($19)	($22)	($10)	($11)	($11)	($11)	($11)	($9)	($9)	($9)	($9)	($10)	($9)	($10)	($10)	($8)
Other Variable Costs	($67)	$0	($0)	($0)	($1)	($2)	($3)	($3)	($4)	($3)	($4)	($6)	($6)	($6)	($11)	($13)	($13)	($5)	($5)	($8)	($11)	($10)	($10)	($10)	($10)	($10)	($8)	($8)	($8)	($9)	($9)	($9)	($9)	($9)	($7)
System Fixed Costs	($754)	$0	$0	$0	($0)	($31)	($55)	($58)	($63)	($65)	($66)	($69)	($85)	($86)	($95)	($87)	($113)	($88)	($87)	($58)	($57)	($96)	($98)	($101)	($103)	($101)	($81)	($82)	($84)	($86)	($88)	($85)	($92)	($94)	($72)
Net System Impacts	($1,652)	$0	($0)	($0)	($18)	($90)	($116)	($119)	($119)	($134)	($134)	($139)	($152)	($157)	($175)	($166)	($196)	($205)	($214)	($241)	($233)	($213)	($217)	($224)	($228)	($224)	($178)	($181)	($185)	($191)	($194)	($188)	($203)	($207)	($158)
Net (Benefit)/Cost	$93	$0	($0)	($0)	($3)	$56	$36	$15	$1	($20)	($30)	($38)	($46)	($51)	($43)	$90	$58	$46	$31	$2	$13	$37	$33	$27	$24	$29	$12	$9	$5	$0	($1)	$8	($0)	$11	$1

Low Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$681	$0	$0	$0	$12	$90	$87	$84	$81	$78	$76	$73	$71	$69	$66	$64	$61	$59	$57	$54	$53	$52	$51	$50	$49	$48	$47	$46	$45	$44	$44	$43	$42	$41	$40
Incremental Transmission Revenue	($82)	$0	$0	$0	($1)	($11)	($10)	($10)	($10)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
New Wind PPA	$318	$0	$0	$0	$0	$0	$24	$25	$26	$28	$29	$30	$44	$45	$44	$49	$50	$49	$47	$47	$52	$57	$58	$60	$61	$62	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Wind Capital Recovery	$1,360	$0	$0	$0	$29	$179	$164	$152	$143	$135	$132	$130	$128	$127	$126	$125	$123	$122	$121	$120	$119	$118	$117	$116	$115	$115	$115	$115	$115	$116	$118	$121	$127	$142	$91
New Wind O&M	$263	$0	$0	$0	$3	$19	$20	$20	$22	$22	$23	$23	$24	$24	$25	$26	$26	$27	$28	$28	$29	$30	$30	$31	$32	$33	$34	$35	$35	$36	$37	$38	$39	$40	$34
New Wind PTCs	($795)	$0	$0	$0	($29)	($131)	($131)	($136)	($142)	($141)	($146)	($146)	($152)	($151)	($121)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,745	$0	$0	$0	$14	$146	$152	$134	$120	$114	$104	$101	$106	$106	$132	$256	$254	$250	$245	$243	$246	$250	$250	$251	$252	$253	$190	$190	$190	$191	$193	$197	$203	$218	$160
System Impacts																																			
NPC	($600)	$0	$0	$0	($17)	($57)	($58)	($58)	($54)	($61)	($60)	($58)	($44)	($39)	($51)	($62)	($83)	($23)	($43)	($85)	($102)	($64)	($66)	($68)	($69)	($68)	($54)	($55)	($56)	($58)	($59)	($57)	($61)	($63)	($48)
Emissions	($331)	$0	$0	$0	$0	$0	$0	$0	$0	($8)	($18)	($31)	($42)	($49)	($50)	($61)	($71)	($31)	($44)	($38)	($71)	($57)	($58)	($60)	($61)	($60)	($48)	($48)	($49)	($51)	($52)	($50)	($54)	($55)	($42)
Other Variable Costs	($43)	$0	$0	$0	($0)	($1)	($2)	($2)	($3)	($2)	($2)	($3)	($3)	($3)	($5)	($6)	($5)	($3)	($9)	($11)	($10)	($6)	($7)	($7)	($7)	($7)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($5)
System Fixed Costs	($964)	$0	$0	$0	($0)	($31)	($55)	($58)	($62)	($65)	($66)	($68)	($100)	($103)	($123)	($97)	($85)	($185)	($159)	($176)	($75)	($136)	($139)	($143)	($146)	($143)	($114)	($116)	($118)	($122)	($124)	($121)	($130)	($132)	($101)
Net System Impacts	($1,939)	$0	$0	$0	($17)	($89)	($116)	($118)	($119)	($136)	($146)	($160)	($189)	($194)	($229)	($225)	($245)	($242)	($253)	($310)	($258)	($264)	($270)	($278)	($283)	($278)	($221)	($225)	($229)	($237)	($241)	($234)	($252)	($256)	($196)
Net (Benefit)/Cost	($194)	$0	$0	$0	($3)	$57	$37	$16	$1	($22)	($42)	($59)	($82)	($88)	($97)	$30	$9	$8	($9)	($67)	($12)	($14)	($19)	($27)	($31)	($25)	($31)	($35)	($39)	($46)	($47)	($37)	($49)	($38)	($37)

Estimated Annual Revenue Requirement Results ($ million)

OFPC Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Project Net Costs																		
Transmission Project Capital Recovery	$681	$0	$0	$0	$12	$90	$87	$84	$81	$78	$76	$73	$71	$69	$66	$64	$61	$59
Incremental Transmission Revenue	($82)	$0	$0	$0	($1)	($11)	($10)	($10)	($10)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($7)	($7)
New Wind PPA	$318	$0	$0	$0	$0	$0	$24	$25	$26	$28	$29	$30	$44	$45	$44	$49	$50	$49
New Wind Capital Recovery	$1,360	$0	$0	$0	$29	$179	$164	$152	$143	$135	$132	$130	$128	$127	$126	$125	$123	$122
New Wind O&M	$263	$0	$0	$0	$3	$19	$20	$20	$22	$22	$23	$23	$24	$24	$25	$26	$26	$27
New Wind PTCs	($795)	$0	$0	$0	($29)	($131)	($131)	($136)	($142)	($141)	($146)	($146)	($152)	($151)	($121)	$0	$0	$0
Net Project Cost	$1,745	$0	$0	$0	$14	$146	$152	$134	$120	$114	$104	$101	$106	$106	$132	$256	$254	$250
System Impacts																		
NPC	($699)	$0	$0	($0)	($17)	($60)	($63)	($66)	($69)	($75)	($70)	($72)	($66)	($82)	($56)	($72)	($98)	($73)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($14)	$0	$0	$0	$1	($0)	($1)	($0)	$0	$0	($1)	($1)	$0	($2)	($6)	($6)	($7)	$0
System Fixed Costs	($1,085)	$0	$0	$0	($0)	($31)	($55)	($58)	($63)	($65)	($66)	($69)	($104)	($117)	($171)	($120)	($78)	($140)
Net System Impacts	($1,798)	$0	$0	$0	($17)	($91)	($119)	($124)	($131)	($140)	($137)	($141)	($170)	($201)	($232)	($198)	($183)	($213)
Net (Benefit)/Cost	($53)	$0	$0	$0	($3)	$55	$33	$10	($11)	($27)	($33)	($40)	($64)	($95)	($101)	$58	$71	$37

(Benefit)/Cost	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																	
Transmission Project Capital Recovery	$57	$54	$53	$52	$51	$50	$49	$48	$47	$46	$45	$44	$44	$43	$42	$41	$40
Incremental Transmission Revenue	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
New Wind PPA	$47	$47	$52	$57	$58	$60	$61	$62	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Wind Capital Recovery	$121	$120	$119	$118	$117	$116	$115	$115	$115	$115	$115	$116	$118	$121	$127	$142	$91
New Wind O&M	$28	$28	$29	$30	$30	$31	$32	$33	$34	$35	$35	$36	$37	$38	$39	$40	$34
New Wind PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$245	$243	$246	$250	$250	$251	$252	$253	$190	$190	$190	$191	$193	$197	$203	$218	$160
System Impacts																	
NPC	($77)	$27	($94)	($75)	($77)	($79)	($81)	($79)	($63)	($64)	($65)	($67)	($69)	($67)	($72)	($73)	($56)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($1)	$1	$1	($3)	($3)	($3)	($3)	($3)	($2)	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($2)
System Fixed Costs	($140)	($264)	($170)	($159)	($162)	($167)	($170)	($167)	($133)	($135)	($138)	($143)	($145)	($141)	($152)	($154)	($118)
Net System Impacts	($217)	($236)	($262)	($237)	($242)	($249)	($254)	($249)	($198)	($202)	($206)	($213)	($216)	($210)	($226)	($230)	($176)
Net (Benefit)/Cost	$28	$7	($16)	$13	$8	$2	($2)	$3	($8)	($12)	($16)	($21)	($23)	($13)	($23)	($12)	($17)

Medium Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Project Net Costs																		
Transmission Project Capital Recovery	$681	$0	$0	$0	$12	$90	$87	$84	$81	$78	$76	$73	$71	$69	$66	$64	$61	$59
Incremental Transmission Revenue	($82)	$0	$0	$0	($1)	($11)	($10)	($10)	($10)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($7)	($7)
New Wind PPA	$318	$0	$0	$0	$0	$0	$24	$25	$26	$28	$29	$30	$44	$45	$44	$49	$50	$49
New Wind Capital Recovery	$1,360	$0	$0	$0	$29	$179	$164	$152	$143	$135	$132	$130	$128	$127	$126	$125	$123	$122
New Wind O&M	$263	$0	$0	$0	$3	$19	$20	$20	$22	$22	$23	$23	$24	$24	$25	$26	$26	$27
New Wind PTCs	($795)	$0	$0	$0	($29)	($131)	($131)	($136)	($142)	($141)	($146)	($146)	($152)	($151)	($121)	$0	$0	$0
Net Project Cost	$1,745	$0	$0	$0	$14	$146	$152	$134	$120	$114	$104	$101	$106	$106	$132	$256	$254	$250
System Impacts																		
NPC	($888)	$0	($0)	($0)	($18)	($63)	($67)	($69)	($69)	($74)	($69)	($71)	($66)	($72)	($54)	($99)	($132)	($135)
Emissions	($84)	$0	$0	$0	$0	$0	$0	$0	$0	($6)	($7)	($8)	($9)	($8)	($9)	($12)	($16)	($13)
Other Variable Costs	$6	$0	$0	$0	$0	($1)	($2)	($1)	$0	$0	$0	$1	$2	$3	($3)	($3)	($4)	$4
System Fixed Costs	($916)	$0	$0	$0	($0)	($31)	($56)	($58)	($63)	($65)	($67)	($69)	($105)	($108)	($175)	($117)	($52)	($89)
Net System Impacts	($1,882)	$0	$0	$0	($18)	($95)	($124)	($128)	($132)	($146)	($143)	($147)	($178)	($185)	($241)	($231)	($203)	($233)
Net (Benefit)/Cost	($137)	$0	$0	$0	($4)	$51	$28	$7	($11)	($32)	($39)	($46)	($72)	($79)	($109)	$24	$51	$17

(Benefit)/Cost	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																	
Transmission Project Capital Recovery	$57	$54	$53	$52	$51	$50	$49	$48	$47	$46	$45	$44	$44	$43	$42	$41	$40
Incremental Transmission Revenue	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
New Wind PPA	$47	$47	$52	$57	$58	$60	$61	$62	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Wind Capital Recovery	$121	$120	$119	$118	$117	$116	$115	$115	$115	$115	$115	$116	$118	$121	$127	$142	$91
New Wind O&M	$28	$28	$29	$30	$30	$31	$32	$33	$34	$35	$35	$36	$37	$38	$39	$40	$34
New Wind PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$245	$243	$246	$250	$250	$251	$252	$253	$190	$190	$190	$191	$193	$197	$203	$218	$160
System Impacts																	
NPC	($143)	($135)	($66)	($110)	($112)	($116)	($118)	($116)	($92)	($94)	($96)	($99)	($100)	($97)	($105)	($107)	($82)
Emissions	($15)	($17)	($14)	($14)	($14)	($14)	($15)	($14)	($12)	($12)	($12)	($12)	($13)	($12)	($13)	($13)	($10)
Other Variable Costs	$4	$5	$4	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1	$1
System Fixed Costs	($88)	($97)	($182)	($127)	($129)	($133)	($136)	($133)	($106)	($108)	($110)	($114)	($116)	($112)	($121)	($123)	($94)
Net System Impacts	($243)	($243)	($258)	($249)	($254)	($262)	($267)	($262)	($208)	($212)	($217)	($223)	($227)	($220)	($238)	($242)	($185)
Net (Benefit)/Cost	$2	($0)	($11)	$1	($4)	($11)	($15)	($10)	($18)	($22)	($26)	($32)	($34)	($24)	($35)	($24)	($26)

Medium Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Project Net Costs																		
Transmission Project Capital Recovery	$681	$0	$0	$0	$12	$90	$87	$84	$81	$78	$76	$73	$71	$69	$66	$64	$61	$59
Incremental Transmission Revenue	($82)	$0	$0	$0	($1)	($11)	($10)	($10)	($10)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($7)	($7)
New Wind PPA	$318	$0	$0	$0	$0	$0	$24	$25	$26	$28	$29	$30	$44	$45	$44	$49	$50	$49
New Wind Capital Recovery	$1,360	$0	$0	$0	$29	$179	$164	$152	$143	$135	$132	$130	$128	$127	$126	$125	$123	$122
New Wind O&M	$263	$0	$0	$0	$3	$19	$20	$20	$22	$22	$23	$23	$24	$24	$25	$26	$26	$27
New Wind PTCs	($795)	$0	$0	$0	($29)	($131)	($131)	($136)	($142)	($141)	($146)	($146)	($152)	($151)	($121)	$0	$0	$0
Net Project Cost	$1,745	$0	$0	$0	$14	$146	$152	$134	$120	$114	$104	$101	$106	$106	$132	$256	$254	$250
System Impacts																		
NPC	($658)	$0	$0	$0	($17)	($62)	($66)	($66)	($66)	($71)	($68)	($71)	($56)	($66)	($47)	($43)	($41)	($92)
Emissions	($377)	$0	$0	$0	$0	$0	$0	$0	$0	($9)	($18)	($28)	($43)	($60)	($50)	($51)	($60)	($53)
Other Variable Costs	($107)	$0	$0	($1)	($1)	($3)	($4)	($5)	($6)	($6)	($6)	($6)	($7)	($7)	($8)	($10)	($11)	($22)
System Fixed Costs	($921)	$0	$0	$0	($0)	($31)	($55)	($58)	($63)	($65)	($66)	($68)	($88)	($83)	($129)	($134)	($137)	($131)
Net System Impacts	($2,062)	$0	$0	($0)	($19)	($96)	($125)	($130)	($134)	($151)	($158)	($173)	($193)	($216)	($235)	($238)	($248)	($298)
Net (Benefit)/Cost	($317)	$0	$0	($0)	($4)	$50	$27	$5	($14)	($38)	($55)	($72)	($87)	($110)	($103)	$17	$6	($48)

(Benefit)/Cost	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																	
Transmission Project Capital Recovery	$57	$54	$53	$52	$51	$50	$49	$48	$47	$46	$45	$44	$44	$43	$42	$41	$40
Incremental Transmission Revenue	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
New Wind PPA	$47	$47	$52	$57	$58	$60	$61	$62	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Wind Capital Recovery	$121	$120	$119	$118	$117	$116	$115	$115	$115	$115	$115	$116	$118	$121	$127	$142	$91
New Wind O&M	$28	$28	$29	$30	$30	$31	$32	$33	$34	$35	$35	$36	$37	$38	$39	$40	$34
New Wind PTCs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$245	$243	$246	$250	$250	$251	$252	$253	$190	$190	$190	$191	$193	$197	$203	$218	$160
System Impacts																	
NPC	($101)	($27)	($76)	($68)	($69)	($71)	($73)	($71)	($57)	($58)	($59)	($61)	($62)	($60)	($65)	($66)	($50)
Emissions	($58)	($85)	($78)	($66)	($67)	($69)	($70)	($69)	($55)	($56)	($57)	($59)	($60)	($58)	($63)	($64)	($49)
Other Variable Costs	($24)	($25)	($22)	($16)	($16)	($17)	($17)	($17)	($13)	($14)	($14)	($14)	($15)	($14)	($15)	($15)	($12)
System Fixed Costs	($129)	($100)	($97)	($128)	($131)	($134)	($137)	($135)	($107)	($109)	($111)	($115)	($117)	($113)	($122)	($124)	($95)
Net System Impacts	($312)	($237)	($273)	($277)	($283)	($292)	($297)	($292)	($232)	($236)	($241)	($249)	($253)	($246)	($265)	($269)	($206)
Net (Benefit)/Cost	($67)	$6	($26)	($27)	($33)	($41)	($46)	($39)	($42)	($46)	($51)	($58)	($60)	($49)	($62)	($51)	($47)

Estimated Annual Revenue Requirement Results ($ million)

High Natural Gas, Zero CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$681	$0	$0	$0	$12	$90	$87	$84	$81	$78	$76	$73	$71	$69	$66	$64	$61	$59	$57	$54	$53	$52	$51	$50	$49	$48	$47	$46	$45	$44	$44	$43	$42	$41	$40
Incremental Transmission Revenue	($82)	$0	$0	$0	($1)	($11)	($10)	($10)	($10)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
New Wind PPA	$318	$0	$0	$0	$0	$0	$24	$25	$26	$28	$29	$30	$44	$45	$44	$49	$50	$49	$47	$47	$52	$57	$58	$60	$61	$62	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Wind Capital Recovery	$1,360	$0	$0	$0	$29	$179	$164	$152	$143	$135	$132	$130	$128	$127	$126	$125	$123	$122	$121	$120	$119	$118	$117	$116	$115	$115	$115	$115	$115	$116	$118	$121	$127	$142	$91
New Wind O&M	$263	$0	$0	$0	$3	$19	$20	$20	$22	$22	$23	$23	$24	$24	$25	$26	$26	$27	$28	$28	$29	$30	$30	$31	$32	$33	$34	$35	$35	$36	$37	$38	$39	$40	$34
New Wind PTCs	($795)	$0	$0	$0	($29)	($131)	($131)	($136)	($142)	($141)	($146)	($146)	($152)	($151)	($121)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,745	$0	$0	$0	$14	$146	$152	$134	$120	$114	$104	$101	$106	$106	$132	$256	$254	$250	$245	$243	$246	$250	$250	$251	$252	$253	$190	$190	$190	$191	$193	$197	$203	$218	$160
System Impacts																																			
NPC	($1,010)	$0	$0	$0	($22)	($78)	($88)	($83)	($82)	($89)	($84)	($87)	($80)	$2	($112)	($93)	($115)	($172)	($175)	($120)	($147)	($120)	($122)	($126)	($128)	($126)	($100)	($102)	($104)	($107)	($109)	($106)	($114)	($116)	($89)
Emissions	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other Variable Costs	($8)	$0	($0)	($0)	($1)	($0)	($1)	($2)	($1)	($0)	($1)	($1)	($1)	$2	$0	$1	$0	($4)	($0)	($3)	($3)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)	($1)
System Fixed Costs	($1,067)	$0	$0	$0	($0)	($31)	($55)	($65)	($70)	($73)	($74)	($76)	($92)	($224)	($101)	($130)	($113)	($112)	($125)	($164)	($147)	($152)	($155)	($160)	($163)	($160)	($127)	($129)	($132)	($136)	($139)	($135)	($145)	($148)	($113)
Net System Impacts	($2,086)	$0	($0)	($0)	($23)	($109)	($144)	($149)	($153)	($161)	($159)	($165)	($173)	($220)	($213)	($222)	($227)	($288)	($300)	($287)	($296)	($272)	($278)	($286)	($292)	($287)	($228)	($232)	($237)	($244)	($248)	($241)	($260)	($264)	($203)
Net (Benefit)/Cost	($341)	$0	($0)	($0)	($9)	$37	$8	($15)	($33)	($48)	($55)	($63)	($66)	($115)	($82)	$34	$27	($38)	($55)	($44)	($50)	($22)	($28)	($36)	($40)	($34)	($38)	($42)	($47)	($53)	($55)	($44)	($57)	($46)	($43)

High Natural Gas, Medium CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$681	$0	$0	$0	$12	$90	$87	$84	$81	$78	$76	$73	$71	$69	$66	$64	$61	$59	$57	$54	$53	$52	$51	$50	$49	$48	$47	$46	$45	$44	$44	$43	$42	$41	$40
Incremental Transmission Revenue	($82)	$0	$0	$0	($1)	($11)	($10)	($10)	($10)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
New Wind PPA	$318	$0	$0	$0	$0	$0	$24	$25	$26	$28	$29	$30	$44	$45	$44	$49	$50	$49	$47	$47	$52	$57	$58	$60	$61	$62	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Wind Capital Recovery	$1,360	$0	$0	$0	$29	$179	$164	$152	$143	$135	$132	$130	$128	$127	$126	$125	$123	$122	$121	$120	$119	$118	$117	$116	$115	$115	$115	$115	$115	$116	$118	$121	$127	$142	$91
New Wind O&M	$263	$0	$0	$0	$3	$19	$20	$20	$22	$22	$23	$23	$24	$24	$25	$26	$26	$27	$28	$28	$29	$30	$30	$31	$32	$33	$34	$35	$35	$36	$37	$38	$39	$40	$34
New Wind PTCs	($795)	$0	$0	$0	($29)	($131)	($131)	($136)	($142)	($141)	($146)	($146)	($152)	($151)	($121)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,745	$0	$0	$0	$14	$146	$152	$134	$120	$114	$104	$101	$106	$106	$132	$256	$254	$250	$245	$243	$246	$250	$250	$251	$252	$253	$190	$190	$190	$191	$193	$197	$203	$218	$160
System Impacts																																			
NPC	($1,045)	$0	$0	$0	($21)	($76)	($85)	($83)	($82)	($88)	($83)	($85)	($79)	($92)	($121)	($75)	($145)	($117)	($131)	($134)	($149)	($127)	($130)	($134)	($137)	($134)	($107)	($109)	($111)	($114)	($116)	($113)	($122)	($124)	($95)
Emissions	($71)	$0	$0	$0	$0	$0	$0	$0	$0	($6)	($7)	($8)	($7)	($8)	($8)	($6)	($12)	($11)	($12)	($14)	($16)	($11)	($12)	($12)	($12)	($12)	($9)	($10)	($10)	($10)	($10)	($10)	($11)	($11)	($8)
Other Variable Costs	($116)	$0	($0)	($1)	($3)	($5)	($6)	($6)	($8)	($8)	($9)	($9)	($10)	($10)	($12)	($13)	($15)	($17)	($17)	($16)	($18)	($16)	($16)	($16)	($17)	($16)	($13)	($13)	($14)	($14)	($14)	($14)	($15)	($15)	($12)
System Fixed Costs	($864)	$0	$0	$0	($0)	($31)	($55)	($58)	($63)	($65)	($66)	($68)	($85)	($83)	($86)	($142)	($54)	($135)	($125)	($122)	($124)	($117)	($120)	($123)	($126)	($124)	($98)	($100)	($102)	($105)	($107)	($104)	($112)	($114)	($87)
Net System Impacts	($2,096)	$0	($0)	($1)	($24)	($112)	($147)	($147)	($152)	($167)	($165)	($171)	($182)	($193)	($227)	($237)	($227)	($280)	($286)	($286)	($307)	($272)	($278)	($286)	($291)	($286)	($227)	($231)	($236)	($244)	($248)	($241)	($259)	($264)	($202)
Net (Benefit)/Cost	($351)	$0	($0)	($1)	($10)	$34	$6	($13)	($32)	($53)	($61)	($69)	($75)	($87)	($95)	$19	$27	($30)	($41)	($43)	($61)	($22)	($27)	($35)	($40)	($33)	($37)	($41)	($46)	($53)	($54)	($44)	($56)	($46)	($43)

High Natural Gas, High CO2 Price-Policy Scenario

(Benefit)/Cost	*PVRR(d)*	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Project Net Costs																																			
Transmission Project Capital Recovery	$681	$0	$0	$0	$12	$90	$87	$84	$81	$78	$76	$73	$71	$69	$66	$64	$61	$59	$57	$54	$53	$52	$51	$50	$49	$48	$47	$46	$45	$44	$44	$43	$42	$41	$40
Incremental Transmission Revenue	($82)	$0	$0	$0	($1)	($11)	($10)	($10)	($10)	($9)	($9)	($9)	($9)	($8)	($8)	($8)	($7)	($7)	($7)	($7)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($5)	($5)	($5)	($5)	($5)	($5)	($5)
New Wind PPA	$318	$0	$0	$0	$0	$0	$24	$25	$26	$28	$29	$30	$44	$45	$44	$49	$50	$49	$47	$47	$52	$57	$58	$60	$61	$62	$0	$0	$0	$0	$0	$0	$0	$0	$0
New Wind Capital Recovery	$1,360	$0	$0	$0	$29	$179	$164	$152	$143	$135	$132	$130	$128	$127	$126	$125	$123	$122	$121	$120	$119	$118	$117	$116	$115	$115	$115	$115	$115	$116	$118	$121	$127	$142	$91
New Wind O&M	$263	$0	$0	$0	$3	$19	$20	$20	$22	$22	$23	$23	$24	$24	$25	$26	$26	$27	$28	$28	$29	$30	$30	$31	$32	$33	$34	$35	$35	$36	$37	$38	$39	$40	$34
New Wind PTCs	($795)	$0	$0	$0	($29)	($131)	($131)	($136)	($142)	($141)	($146)	($146)	($152)	($151)	($121)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Net Project Cost	$1,745	$0	$0	$0	$14	$146	$152	$134	$120	$114	$104	$101	$106	$106	$132	$256	$254	$250	$245	$243	$246	$250	$250	$251	$252	$253	$190	$190	$190	$191	$193	$197	$203	$218	$160
System Impacts																																			
NPC	($753)	$0	$0	$0	($22)	($78)	($87)	($85)	($84)	($91)	($87)	($91)	$3	($84)	($81)	($50)	($78)	($68)	($63)	($55)	($103)	($70)	($72)	($74)	($75)	($74)	($59)	($60)	($61)	($63)	($64)	($62)	($67)	($68)	($52)
Emissions	($253)	$0	$0	$0	$0	$0	$0	$0	$0	($8)	($16)	($25)	($10)	($46)	($43)	($43)	($48)	($35)	($33)	($35)	($54)	($43)	($44)	($45)	($46)	($45)	($36)	($37)	($37)	($39)	($39)	($38)	($41)	($42)	($32)
Other Variable Costs	($52)	$0	$0	($0)	($1)	($1)	($2)	($3)	($4)	($3)	($4)	($5)	($4)	($6)	($6)	($7)	($7)	($10)	($8)	($6)	($8)	($7)	($8)	($8)	($8)	($8)	($6)	($6)	($6)	($7)	($7)	($7)	($7)	($7)	($6)
System Fixed Costs	($1,282)	$0	$0	$0	($0)	($31)	($55)	($58)	($63)	($65)	($66)	($68)	($195)	($86)	($124)	($186)	($139)	($194)	($212)	($217)	($262)	($196)	($200)	($206)	($210)	($206)	($164)	($167)	($170)	($176)	($178)	($173)	($187)	($190)	($146)
Net System Impacts	($2,340)	$0	$0	($0)	($23)	($110)	($145)	($145)	($150)	($168)	($174)	($189)	($205)	($222)	($254)	($286)	($273)	($306)	($316)	($313)	($427)	($316)	($323)	($333)	($339)	($333)	($264)	($269)	($275)	($284)	($288)	($280)	($302)	($307)	($235)
Net (Benefit)/Cost	($595)	$0	$0	($0)	($9)	$36	$8	($11)	($30)	($54)	($70)	($87)	($99)	($116)	($122)	($31)	($19)	($56)	($71)	($70)	($181)	($66)	($73)	($82)	($87)	($80)	($75)	($79)	($85)	($93)	($95)	($83)	($99)	($89)	($76)

CERTIFICATE OF SERVICE

Docket No. 17-035-23

I hereby certify that on August 31, 2017, a true and correct copy of the foregoing was served by electronic mail and/or overnight delivery to the following:

Utah Office of Consumer Services	
Cheryl Murray Utah Office of Consumer Services 160 East 300 South, 2nd Floor Salt Lake City, UT 84111 cmurray@utah.gov	Michele Beck Utah Office of Consumer Services 160 East 300 South, 2nd Floor Salt Lake City, UT 84111 mbeck@utah.gov
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