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May 24, 2023

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
Request for a General Rate Revision.
Docket No. UE 416

Dear Filing Center:

Please find enclosed the redacted version of the Opening Net Variable Power Cost ("NVPC") Testimony and Exhibits of Bradley G. Mullins (AWEC/100-106) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Please note AWEC's Opening NVPC Testimony and Exhibits contain Protected Information Subject to Modified General Protective Order No. 23-039 and Highly Confidential Information Subject to Modified Order No. 23-138. The confidential portions of AWEC's filing have been encrypted with 7-zip software and are being transmitted electronically to the Commission and qualified persons.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **Confidential and Highly Confidential Opening NVPC Testimony of the Alliance of Western Energy Consumers** upon the parties shown below via electronic mail.

Dated at Portland, Oregon, this 24th day of May, 2023.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matter of	)
	)
Portland General Electric Company,	)
	)
Request For a General Rate Revision.	)
	)

OPENING NET VARIABLE POWER COST ("NVPC") TESTIMONY

OF

BRADLEY G. MULLINS

ON BEHALF OF

THE ALLIANCE OF WESTERN ENERGY CONSUMERS

Protected Information Subject to Modified General Protective Order
(REDACTED)

Highly Confidential Information Subject to Modified Protective Order No. 23-138
(REDACTED

May 24, 2023

TABLE OF CONTENTS

EXHIBIT LIST

AWEC/101 – Qualification Statement of Bradley G. Mullins

AWEC/102 – PGE Responses to Data Requests

AWEC/103 – PowerEx Mid-Columbia WSPP Product Definitions

AWEC/104 – Production Tax Credit Rate Forecast for 2024

Confidential AWEC/105 – Beaver Cycling History

AWEC/106 – Oregonian Articles Discussing Biglow Turbine Failures

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Bradley G. Mullins. I am a consultant representing utility customers before state public utility commissions in the Northwest and Intermountain West. My witness qualification statement can be found in **Exhibit AWEC/101**.

Q. PLEASE IDENTIFY THE PARTY ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are large energy users in the Western United States, including customers receiving electric services from Portland General Electric Company ("PGE" or "Company")).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss my initial review of PGE's proposed $867,132,398 Net Variable Power Costs ("NVPC") forecast for calendar year 2024,[1] including my review of the MONET modeling supporting the 18.7% or $136,894,052 increase to NVPC relative to the $730,238,346 NVPC forecast in PGE's final update in Docket UE 402 (the "2023 AUT") for calendar year 2023.[2]

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The NVPC rate increase PGE is seeking in this proceeding is not justified. As I discuss below, the increase PGE proposes is being driven by several erroneous assumptions and inaccurate modeling approaches. I recommend the Commission adopt several adjustments to PGE's proposed NVPC that will result in a more accurate forecast of 2024 costs. My

1 *See* Docket No. UE 416, PGE's March 31, 2023 MONET Update (March 31, 2023).

2 *See* Docket UE 402, PGE's November 15, 2022 MONET Update (Nov. 15, 2022).

recommendations are summarized in Confidential Table 1, below, followed by a brief description of each issue. offset

Confidential Table 1
AWEC Recommended AUT Adjustments
(Whole Dollars)

1	**PGE March 31, 2023 Update**	**$ 867,132,398**
2	**Adjustments:**	[redacted]
3	Flexibility Down Reserves	[redacted]
4	Washington CCA Allowances	[redacted]
5	Mid-C Specified, Zero Carbon Sales	[redacted]
6	Production Tax Credit Rate	[redacted]
7	Gas Option Placeholder	[redacted]
8	Reliability Contingency Event	[redacted]
9	Thermal Parameters	[redacted]
10	Beaver Cycling	[redacted]
11	Carty Outage Rate	[redacted]
12	2023 AUT - Trans. RDC	[redacted]
13	2023 AUT - BP-24 Wheeling Rates	[redacted]
14	2024 Wheeling Expenses	[redacted]
15	Biglow Capacity Factor	[redacted]
16	Balancing Impacts*	[redacted]
17	Total Adjustments	**(161,910,711)**
18	**Adjusted**	**$ 705,221,687**

*Counterbalancing impacts of all adjustments

Flexibility Down Reserves: I recommend flexibility down reserves be allocated to thermal resources prior to being allocated to hydro resources, which eliminates unnecessary hydro spill in MONET.

Washington Climate Commitment Act Allowances: I recommend that Mid-Columbia ("Mid-C") index prices be adjusted for the impact of the Washington Climate Commitment Act ("CCA") and that allowance costs be removed because they will be offset by increased revenue from selling Washington CCA Compliant power products.

Specified Source Non-Emitting Sales: I recommend modeling incremental revenues from the sale of non-emitting power from specified sources in the Mid-C bilateral market.

Production Tax Credit ("PTC") Rate: I recommend that the production tax credit rate increase to 30 cents per kWh, consistent with inflationary trends expected through the end of 2023.

Gas Option Placeholder: I recommend that the cost of a placeholder gas option be removed from NVPC on the basis that it is both imprudent and an extrinsic value, which based on Commission precedent is not includible in forecast NVPC.

Reliability Contingency Event: I recommend PGE's provisional costs for a reliability contingency event be removed from the NVPC forecast because the median conditions included in the forecast do not also consider beneficial operating events, such as low and negative prices during oversupply events.

Thermal Parameters: I recommend the thermal plant capacities be updated to be consistent with the thermal capacities PGE reports to the EIM in its master file submissions.

Beaver Cycling: I recommend Beaver cycling parameters be updated to be consistent with its actual historical cycling operations.

Carty Outage Rate: I recommend Carty's outage rate be adjusted to remove an imprudent outage from 2021, which non-Company parties identified in Joint Testimony in Docket No. UE 406.

2023 AUT Stipulation – Bonneville Power Administration ("BPA") 2023 Reserves Distribution Clause: I recommend that the 2023 BPA Reserves Distribution Clause ("RDC") benefits be returned to ratepayers in this docket consistent with the Stipulation in the 2023 AUT.

2023 AUT Stipulation – BP-24 Wheeling Rates: I recommend the difference between the actual BP-24 wheeling rates and the BP-24 wheeling rates assumed in the 2023 AUT be returned to ratepayers in this docket consistent with the Stipulation in the 2023 AUT.

BPA 2024 Wheeling Expense: I recommend an unsupported rate increase assumed for BPA wheeling rates in the fourth quarter of 2024 be removed from the NVPC forecast.

Biglow Capacity Factor: I recommend that the capacity factor for Biglow be calculated over the period 2019 through 2021, excluding the abnormal conditions in 2022 resulting from turbine failures.

II. FLEXIBILITY DOWN RESERVES

Q. WHAT IS YOUR RECOMMENDATION RELATED TO FLEXIBILITY DOWN RESERVES?

A. The reserves logic and Visual Basic models that PGE uses to forecast the cost of reserves in the MONET model are severely flawed. The reserves modeling that PGE uses is not optimized with system dispatch and results in sub-optimal, uneconomic hydro dispatch. The reserves logic not only results in dispatching hydro output in uneconomic hours, but includes an assumption that PGE will voluntarily spill, *i.e.*, diverting the water through the impoundment without running it through the generation turbines, a large volume of hydro energy. In fact, in PGE's modeling, this spill occurs in the majority of days in the study year, which is not consistent with how PGE operates its system, nor a prudent technique for holding reserves. The principal cause of this inefficient hydro dispatch is the treatment of downward flexibility reserves, which are being incorrectly allocated entirely to hydro resources without considering the downward flexibility reserves otherwise available at no cost from thermal resources. To correct this issue, I propose an adjustment that allocates downward flexibility reserves to thermal resources prior to being allocated to hydro resources. This change results in a more efficient hydro dispatch and a more accurate forecast of the cost of reserves to PGE. Adopting this change produces $[redacted] reduction to PGE's NVPC forecast.

Q. WHAT ARE RESERVES?

A. Reserves are dispatchable generation capacity that PGE must withhold, or have available, to be capable to respond to uncertainty associated with loads, generation and intermittent resources. The classic example of reserves are contingency reserves, in which a utility must have generation capacity available to respond within ten minutes in a contingency event, such as a forced outage. Thus, rather than selling the full output of a resource into the market, a resource that is holding reserves must be dispatched down in order to respond to such events, resulting in an opportunity cost to the utility. There are several different types of reserves, including both upward reserves and downward reserves. Upward reserves represent capacity that is available to be ramped up within a specified timeframe to accommodate things such as a generator tripping offline or an unexpected increase to load. Downward reserves, on the other hand, represent capacity that is available to be ramped down within a specified timeframe to accommodate things such as an unexpected increase in variable generation or unexpected reduction to load. As noted above, the issue I have identified specifically has to do with downward flexibility reserves.

Q. WHAT CATEGORIES OF RESERVES DOES PGE MODEL IN MONET?

A. PGE models reserves for an increasing number of different reserve categories. First, PGE calculates contingency reserves based on the NERC/WECC standard definitions of 1.5% of load and 1.5% of generation. Contingency reserves are an upward reserve requirement. Second, PGE calculates regulating reserves equal to 1.0% of load. Regulating reserves are modeled as an upward reserve requirement. Third, PGE calculates day-ahead flexibility reserves based on an analysis of historical wind variances between the day-ahead and hour-ahead. Day-ahead flexibility reserves are modeled both as an upward reserve requirement and a downward reserve requirement. Fourth, PGE calculates hour-ahead flexibility reserves based upon historical wind, solar and load variances between the hour-ahead and actual dispatch. Similar to day-ahead flexibility reserves, hour-ahead flexibility reserve requirements are also modeled both as an upward reserve requirement and a downward reserve requirement. Fifth, PGE calculates frequency reserves based on a heuristic analysis. Frequency reserves are modeled as an upward reserve requirement.

Q. DO YOU AGREE WITH ALL OF THESE RESERVE CATEGORIES?

A. No. Many of these reserve requirements are overlapping and not additive. Further, some of the reserve requirements do not actually impact hourly system dispatch, such as day-ahead reserves. For purposes of this testimony, I have not addressed all these issues. Given the relative materiality, this testimony instead focuses on the MONET model logic flaw surrounding downward flexibility reserves that is leading to inaccurate system dispatch.

Q. DO UPWARD RESERVES AND DOWNWARD RESERVES IMPOSE THE SAME COSTS ON A UTILITY'S RESOURCE PORTFOLIO?

A. No. Upward reserves typically impose more costs on a utility's portfolio than downward reserves, although the cost depends on the type of resources in a utility's portfolio. It is often more expensive to hold upward reserves on thermal resources than it is on hydro resources. Conversely, it is often more expensive to hold downward reserves on hydro resources than it is on thermal resources.

Q. WHAT IS THE COST OF DOWNWARD RESERVES?

A. For most utilities with thermal generation, downward reserves can be held at zero cost. Provided that there is sufficient thermal generation online that can be backed down in response to a flexibility down event, no opportunity cost arises from maintaining the online generation levels. Often, downward reserves are ignored altogether in production cost modeling due to the fact that they can be satisfied with no cost from economically dispatched thermal generation resources. Prior to the 2023 AUT, PGE's reserve model, for example, did not consider downward reserve requirements in MONET.

On the other hand, holding downward reserves on hydro resources, as PGE now assumes in MONET, is more expensive than holding downward reserves on thermal resources. As a storage resource, hydro output can be shaped economically to generate more power in high-cost hours and less power in low-cost hours. If generation from a hydro resource is ramped up to hold downward reserves in a low-cost hour, that eliminates power that would otherwise have been available to generate in a high-cost hour, resulting in an opportunity cost to the utility. Therefore, modifying economic hydro dispatch to hold downward reserves is usually only performed as a last resort, as it is a more expensive source of downward reserve capacity than holding downward reserves on thermal resources.

Q. IS THE SAME TRUE FOR UPWARD RESERVES?

A. No. Upward reserves represent an opportunity cost for both thermal resources and hydro resources. If a thermal resource is dispatching economically and a utility is required to ramp down the resource to hold reserves, the utility must purchase power in the market, or forgo a market sale, resulting in higher costs. Considering that the utility also avoids the associated fuel cost, the cost of holding upward reserves on an economic thermal resource can be generalized as the difference between the market prices and the cost of fuel for the generator. In contrast, the cost of holding upward reserves on a hydro resource is often less expensive since any forgone generation can be stored and subsequently used to serve load, albeit potentially at a higher cost.

Q. WHAT IS WRONG WITH PGE'S RESERVES MODELING?

A. PGE's reserve models for hydro and thermal reserves are not integrated. They are performed serially, with hydro reserves allocated prior to thermal reserves and with no co-optimization between the two resource types. Reserves are first allocated to dispatchable hydro resources, and any remaining reserve requirements are then allocated to thermal resources in a second model. Considering the different cost impacts of holding different reserve types on hydro versus thermal resources, this is a major flaw in PGE's reserves modeling method. For upward reserves, the serial approach makes less of difference because it is usually, but not always, less expensive to hold upward reserves on hydro resources prior to holding upward reserves on thermal resources. It makes a significant difference, however, for downward flexibility reserves, including both hour-ahead and day-ahead reserves. It is usually less expensive to hold downward reserves on thermal resources prior to being allocated to hydro resources. As noted above, downward reserves can often be held on thermal resources at no additional cost to the utility. Because of the serial nature of the modeling, however, PGE assigns 100% of downward flexibility reserves to dispatchable hydro resources as the first step in its reserves logic, which is resulting in a distorted system dispatch and overstated NPVC.

Q. HOW DO YOU KNOW THAT THE RESERVES MODEL IS NOT FUNCTIONING AS INTENDED?

A. PGE's reserves modeling results in [redacted] MWh of hydro spill in 2024. Hydro output is valuable and spilling hydro is the most expensive way to hold reserves. Spilling hydro is akin to giving away free power and is therefore an operating measure that utilities avoid. Spilling hydro to generate reserves, for example, would only be resorted to in an emergency. In PGE's model, however, hydro spill is occurring in [redacted] of 366 days of the year. The market value of this spilled energy is worth approximately $[redacted]. This is a clear indication that the MONET reserves modeling is not functioning as intended.

Q. DOES PGE SPILL THAT AMOUNT OF HYDRO IN ACTUAL OPERATIONS?

A. No. In response to AWEC Data Request 93, PGE was not able to identify a single instance where it spilled hydro in order to replenish reserves. The only spill that PGE identified was spill initiated by the Mid-C hydro operators for operational or environmental purposes. While PGE claims that it does not track instances of hydro spill on its own resources, that is hard to believe. Given the cost of spilling hydro power, prudent utility practices otherwise require that instances of hydro spill be tracked for the purpose of being minimized. Based on PGE's response to AWEC Data Request 93, it is apparent that the Mid-Columbia utilities track hydro spill with a high degree of specificity, including instances where PGE would have requested spill for purposes of holding reserves.

Q. WHY IS THE MODEL RESORTING TO SPILLING HYDRO?

A. By allocating all downward flexibility reserves to dispatchable hydro resources, the Mid-Columbia hydro resources must be ramped up uneconomically in every hour of the year, regardless of the market price for power. This not only results in uneconomic hydro dispatch but also reduces the capability of hydro resources to hold upwards reserves. As demonstrated in PGE's response to AWEC Data Request 95, the combination of the Mid-Columbia and the Pelton / Round Butte hydro resources is capable of providing all of the upwards reserves necessary for PGE's operations in most hours of the year. Notwithstanding, ramping up hydro resources to hold downward reserves results in insufficient upward reserve capability necessary to fulfill upward reserve requirements. Due to this faulty logic, these unmet upward reserve requirements are then feeding into the thermal reserves model and ultimately leading to the large volume of hydro spill discussed above. Some of the problem with hydro spill is caused by faults in the thermal reserves model and inaccurate thermal reserve parameters, though given the correction I propose below, it is not necessary to go into the details of those flaws at this time.

Q. IS THE CAPACITY FROM THERMAL RESOURCES SUFFICIENT TO COVER ALL DOWNWARD FLEXIBILITY RESERVES?

A. Yes. The system dispatch of thermal resources already produces enough downward flexibility reserves in every hour, at no incremental system cost, to cover PGE's downward flexibility reserve requirements. Thus, allocating downward flexibility reserves to hydro resources is not necessary.

Q. WHAT CORRECTION DO YOU PROPOSE TO ADDRESS THIS PROBLEM?

A. I recommend that the downward flexibility reserves be allocated first to online thermal resources and allocated to hydro resources only as a last resort. Since online thermal resources can fulfill all the downward flexibility reserve requirements in the study period at no additional cost, I adjusted the flexibility down requirement input into the hydro model to be zero.

Q. HOW DID THIS CHANGE IMPACT NVPC?

A. This change to the MONET reserves logic had a major impact on NVPC. It eliminated all hydro spill and resulted in a more economic dispatch profile than PGE had assumed in its initial filing. As noted above, the impact was a $[redacted] reduction to NVPC. While there are further refinements with PGE's reserves modeling that still need to be addressed in a future proceeding, making this change in this docket will result in a forecast that better corresponds to the actual cost of reserves to PGE.

Q. ARE THERE ANY OTHER ISSUES YOU HAVE IDENTIFIED WITH RESPECT TO DOWNWARD FLEXIBILITY RESERVES?

A. Yes. The EIM manages flexibility reserves. Notwithstanding, utilities are required to meet certain flexibility reserve requirements every hour. Each participating utility is required to meet an hour-ahead flexible ramping sufficiency test and must supply sufficient reserve capacity to meet upward and downward flexible capacity requirements established by EIM. The amount of reserves for each entity is offset by a diversity benefit, since the flexibility reserve requirement for the system as a whole is less than the sum of the flexibility requirements for each of the load-serving EIM entities. PGE provided the actual EIM flexibility reserve requirements in response to AWEC Data Request 96, and based on that response, it is apparent that the amount of downward flexibility reserves included in the MONET model is overstated. This is detailed in Highly Confidential Table 2, below.

Highly Confidential Figure 2

<u>MONET vs. EIM Downward Flexibility Reserves (MW) 2020-2022</u>

[redacted]

In my model, I adjusted the downward reserve requirements to be consistent with the amounts historically calculated by the EIM. Since the higher downward reserve levels PGE assumed could otherwise be held at no cost from online thermal resources, however, this assumption makes no difference to my recommendation.

III. WASHINGTON CLIMATE COMMITMENT ACT

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH PGE'S ADJUSTMENT RELATED TO THE WASHINGTON CLIMATE COMMITMENT ACT.

A. PGE assumes that it has an obligation to comply with the Washington Climate Commitment Act ("CCA").[3] PGE's forecast includes an adjustment to NVPC for sales of power at the Mid-C market hub. To arrive at this adjustment, PGE has asserted that it must purchase Washington CCA allowances for each MWh of power sold at the Mid-C market. This adjustment, however, is flawed in many ways. First, PGE made no effort to evaluate how its thermal plant dispatch will be affected by such a requirement. Second, PGE's forecast assumes that every sale of power at the Mid-C index must be covered by CCA allowances, whereas it is more likely that CCA allowances would only be necessary for a small subset of transactions, if any at all. Third, PGE ignores the complex dynamics of the market price effects associated with the CCA. Sales of power products that are bundled with CCA allowances will demand higher market prices, which will offset the cost of purchasing allowances. Thus, not only is it necessary to remove the Washington CCA adjustment, it is also necessary to adjust the Mid-C index prices downwards to reflect the lower cost for

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3 AWEC will address legal issues and concerns regarding this assumption in legal briefing. Notwithstanding, my testimony should not be interpreted as a concession or waiver of any legal argument that AWEC might raise in briefing.

purchasing power that is delivered outside of Washington State and not subject to the CCA. Finally, I recommend an adjustment that values the additional revenue PGE will be capable of generating by selling non-emitting, specified source power from PGE's hydro and wind resources into the Mid-C market at a premium.

a. <u>Washington Climate Commitment Act Allowance Costs.</u>

Q. WHAT WASHINGTON CLIMATE COMMITMENT ACT COSTS DID PGE INCLUDE IN NVPC?

A. The Washington CCA was passed by the Washington State legislature in 2021. Among other things, the CCA established a "cap and invest" program, which requires certain covered entities to purchase compliance instruments administered by the Washington Department of Ecology ("Ecology") in connection with carbon emissions. Ecology has issued rules implementing the CCA and PGE asserts that it will be required to purchase allowances from Washington to make wholesale sales at the Mid-C market.[4] In its March 31, 2023 update, PGE included $[redacted] of additional costs in its NVPC forecast covering the cost of such allowances in 2024.

Q. HOW DID PGE CALCULATE THIS ADJUSTMENT?

A. PGE assumed it would be necessary to purchase carbon allowances for each MWh of sales it makes at the Mid-Columbia market based on the results of Ecology's February allowance auction. The price of allowances in Ecology's February 2023 allowance auction was $48.50 per metric ton of CO2e ("MTCO2e").[5] The emission factor for unspecified sales is 0.437

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4 PGE/300, Schwartz-Outama-Cristea/30:15-21.

5 State of Washington Department of Ecology, Publication No. 23-02-022, Washington Cap-and-Invest Program Auction #1 February 2023 Summary Report, at 1 (March 7, 2023).

MTCO2e /MWh.[6] Multiplying these values together, the price of allowances for unspecified power is $21.19/MWh, which PGE applied as a reduction to revenues from each sale at the Mid-C market in its NVPC forecast.

Q. DID PGE MODIFY SYSTEM DISPATCH FOR THE ALLEGED CCA ALLOWANCE COSTS?

A. No. PGE is differently situated than Washington utilities that receive free allowances equivalent to the emissions associated with the electricity used to serve their Washington load and administrative costs of the CCA program. In PGE's circumstances, if revenue recognized from each Mid-C sales transaction will be $21.19/MWh less than the market index price, that will have a material impact on how PGE dispatches its system. PGE's adjustment does not capture these offsetting impacts on system dispatch and is therefore inaccurate. For example, some transactions modeled as economic in MONET will no longer be economic and thermal resources would be dispatched more efficiently, reducing costs relative to PGE's adjustment. Conversely, non-emitting hydro resources would be dispatched more heavily in hours when PGE is selling power to the extent those resources can be marketed without requiring the purchase of allowances. These dynamics are material and necessary to consider before assessing any Washington CCA costs to ratepayers.

Q. DOES A CCA COMPLIANCE OBLIGATION APPLY TO ALL TRANSACTIONS AT MID-C?

A. No. The Mid-C market is generally defined based on transactions in the service areas of the three hydro-owning Washington public utilities: Grant PUD, Douglas PUD, and Chelan PUD. As PGE acknowledges, not all transactions at Mid-C will be required to comply with the

6 WAC 173-444-040.

CCA—only transactions with a sink in Washington will be required to be CCA compliant.[7] Further, sales of non-emitting, specified source power would not contribute to a compliance obligation, and therefore, will also not require any allowances. These distinctions are having a major impact on the Mid-C market, which is evolving to include divergent power products to accommodate the CCA.

Q. WHAT NEW PRODUCTS ARE BEING DEVELOPED?

A. Mid-C is a bilateral market trading under the Western Systems Power Pool ("WSPP") Schedule C agreement. Exchange and clearing providers, such as Intercontinental Exchange ("ICE"), also provide a market system to facilitate transactions based on settled market price indexes. In **Exhibit AWEC/103** I have attached notification from PowerEx that describes four distinct Mid-C products surrounding the CCA, including 1) Washington CCA Compliant; 2) Non-Washington Sink; 3) Specified Source, Non-emitting, and 4) Specified Source, Emitting. The first product, Washington CCA Compliant, is a generic power transaction that comes bundled with Washington CCA allowances. The second product, Non-Washington Sink, is a transaction for power exported out of Washington that does not require any purchased allowances. The third and fourth products are for specified power. The PowerEx document describes these generally as a single product, in which the supplier reimburses the purchaser for the cost of Washington CCA allowances, if any, associated with the specified power source. Given the unique characteristics of these products, each will demand a different price in the market. Thus, under this framework, there will no longer be a single market price for power at Mid-C, but rather, differing pricing depending on the type of product supplied.

7 PGE/300, Schwartz-Outama-Cristea/29:6-12.

Q. WILL WASHINGTON CCA COMPLIANT POWER PRODUCTS DEMAND A HIGHER PRICE?

A. Yes. The Washington CCA does not change the supply of generation resources nor the demand for power. Therefore, market fundamentals require that a sale of Washington CCA Compliant power products that are bundled with allowances will demand a higher market price than power which does not require allowances, such as Non-Washington Sink products. Assuming the price for an allowance is $21.19/MWh for unspecified power, the price for a sale of a Washington CCA Compliant power products will, all things equal, be $21.19/MWh higher than the cost of power products that do not require allowances. Conversely, a purchase of power that does not require allowances, such as a Non-Washington Sink power product, will demand a price that is $21.19/MWh less than the price for Washington CCA Compliant power products. These market dynamics are complex, and PGE's oversimplified analysis does not consider them.

Q. HOW WILL THE CCA IMPACT THE MID-C MARKET INDICES?

A. Based on **Exhibit AWEC/103**, there is an assumption that the ICE platform index will be based on Washington CCA Compliant power products. Transactions of Non-Washington Sink and Specified Source products will trade bilaterally, off the market index. This means that the market index is inclusive of the cost of purchasing allowances. It also means that transactions of Non-Washington Sink will be traded bilaterally at prices that are less than the price included in the Washington CCA Complaint index. In other words, all power PGE exports from Mid-C will come at a discount relative to the Mid-C index price.

Q. DID PGE CONSIDER ITS ABILITY TO PURCHASE NON-WASHINGTON SINK POWER PRODUCTS AT A DISCOUNT RELATIVE TO THE INDEX?

A. No. Since the power PGE purchases at Mid-C does not sink in Washington, those purchases will be available at a discount relative to the market index price. This is likely one of the reasons why the Mid-C market index is trading so much higher than the cost of generating from gas resources—because the index includes the cost of allowances. Considering this dynamic, it is necessary to adjust the market price index prices assumed in MONET to be reflective of Non-Washington Sink power purchases.

Q. WHAT IS THE IMPACT OF ADJUSTING THE INDEX PRICE TO BE BASED ON NON-WASHINGTON SINK POWER?

A. I reran the MONET model assuming that Mid-C market prices were $21.19/MWh lower than the Washington CCA Compliant market index prices PGE had assumed. This resulted in a $[redacted] reduction to NVPC.

Q. IS IT NECESSARY TO ADD AN ADDITIONAL ALLOWANCE COST FOR MARKET SALES TRANSACTIONS?

A. No. Sales of Washington CCA Compliant, which will require PGE to procure allowances, will demand higher prices relative to the Non-Washington Sink index prices included in my adjusted NVPC calculations. The additional revenues from those sales will directly offset the cost of purchasing allowances. Accordingly, it is necessary to remove the adder to NVPC that PGE forecast with respect to purchasing CCA allowances. This further reduces NVPC by $[redacted]. Thus, properly considering the market impacts of the Washington CCA results in a $[redacted] reduction to NVPC.

b. Specified Source Non-Emitting Sales

Q. WILL PGE BE ABLE TO FURTHER BENEFIT FROM THE CCA?

A. Contrary to assertions that the CCA will represent an additional cost, the CCA is an economic opportunity for PGE to sell specified source, zero carbon power at a premium in the Mid-C market.

Q. DOES PGE HAVE EXCESS NON-EMITTING RESOURCES?

A. Yes. A major portion of PGE's portfolio is from non-emitting hydro and renewable resources. For example, PGE has historically been able to sell all Renewable Energy Certificates ("RECs") from its Wheatridge facility without implicating its RPS obligations. Further, PGE has sufficient hydro generation, including from its Mid-Columbia hydro shares and its Pelton, Round Butte facility, to serve the sales that it makes at the Mid-C market in most hours of the year.

Q. CAN PGE SELL THIS POWER AT A PREMIUM AS SPECIFIED SOURCE, NON-EMITTING POWER?

A. Yes. While it has made little difference in the past, sales of specified source, non-emitting power products will earn a premium in the market because it will not be necessary to acquire any Washington allowances for those products. PGE did not consider this potential benefit of the CCA when proposing the adjustment identified above.

Q. WHAT AMOUNT OF PREMIUM COULD PGE EARN BY SELLING SPECIFIED SOURCE ZERO CARBON POWER?

A. Assuming the same $21.19/MWh premium discussed above, PGE could potentially earn up to $[redacted] in additional revenues by selling specified source, zero carbon energy into the Mid-C market. Recognizing that the opportunity for such sales may only represent a portion of the sales PGE makes, my recommendation is to assume that half of the sales PGE makes in the

Mid-C market are for specified source, non-emitting power, resulting in a total adjustment of $[redacted].

IV. PRODUCTION TAX CREDIT RATE

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO THE PRODUCTION TAX CREDIT RATE.

A. In its initial filing in this proceeding, PGE forecast a PTC rate of [redacted] cents per kWh, the same value that PGE included in its 2022 AUT filing. As I demonstrate in **Exhibit AWEC/104**, however, the PTC rate, which is set annually based on an index of inflation, will likely increase to 3.0 cents per kWh in 2024, and in no circumstance will the 2024 PTC rate be less than 2.9 cents per kWh. My recommendation is to use a 3.0 cents per kWh rate in this filing, which results in a $[redacted] reduction to NVPC.

Q. HOW DOES THE PTC RATE CHANGE FROM YEAR TO YEAR?

A. The detailed mechanics of the PTC rate were discussed in my Opening Testimony in UE 391 (the "2021 AUT").[8] As noted in that testimony, the IRS adjusts the PTC rate each year by applying an inflation adjustment factor. The inflation adjustment factor is an indexed value calculated based on the GDP implicit price deflator, an economic index of inflation published by the Department of Commerce, Bureau of Economic Analysis. The Bureau of Economic Analysis publishes the GDP implicit price deflator each quarter, and from that information, the expected GDP implicit price deflator value for calendar year 2023, which will be used to establish the 2024 PTC rate, can be assessed.

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[8] Docket No. UE 391, AWEC/100, Mullins/3:12-4:4.

Q. DID THE INFLATION REDUCTION ACT IMPACT THE CALCULATION OF THE PTC?

A. While the Inflation Reduction Act ("IRA") imposes a new PTC rate for new renewable resources placed into service after December 31, 2021, the PTC rate calculation for resources placed into service prior to that date did not change. The IRA PTC rate for new resources is approximately the same as the PTC rate for non-IRA resources, except that it is adjusted in smaller increments, using a slightly different formula.

Q. HOW DID YOU FORECAST THE PTC RATE FOR 2024?

A. In **Exhibit AWEC/104**, I perform a forecast of the PTC rate for 2024 using the same analysis I presented in the 2022 AUT and the 2023 AUT. At the time of drafting this testimony, the Bureau of Economic Analysis has published its GDP implicit price deflator for the first quarter of 2023. Based on that publication, it can be determined that the PTC rate will increase to 3.0 cents per kWh in 2024 so long as inflation equals or exceeds 3.13% on an annualized basis for the remainder of 2023. Given recent indications, it is likely inflation will exceed this level for the remainder of the year. For example, the annualized inflation rate for April 2023 inflation was 4.9%.[9] Further information surrounding the actual inflation rates for 2023, however, will become available as this proceeding progresses.

Q IS THERE ANY CIRCUMSTANCE WHERE THE PTC WILL BE [redacted] CENTS PER KWH?

A. No. Even if one assumes zero inflation for 2023, an impossible scenario given the inflation that has already occurred, the PTC rate will still increase to 2.9 cents per KWh in 2024. Since

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[9] U.S. Department of Labor, Bureau of Labor Statistics, Consumer Price Index April 2023 (May 10, 2023) *available at*: https://www.bls.gov/news.release/pdf/cpi.pdf.

inflation is expected to continue to be elevated in 2023, however, I recommend that a 3.0 cents per kWh rate be used in the 2024 AUT.

V. GAS OPTION PLACEHOLDER

Q. DOES PGE'S FILING INCLUDE ANY PLACEHOLDER CONTRACTS?

A. Yes. PGE's filing includes a placeholder gas option contract with a total premium of $[redacted]. As a general principle, PGE is only allowed to include executed contracts in the AUT, and therefore, this placeholder contract is not appropriately considered in this filing. Further, while it is not yet known what type of option agreement PGE might procure, option contracts, in general, are an uneconomic hedging method for ratepayers, and therefore, are not prudent. Finally, if PGE were to execute such an option contract, an extrinsic value adjustment would be necessary that would offset the entire option premium amount. Accordingly, I recommend that this placeholder option be removed from NVPC, and if PGE does enter into such a contract, that it be found imprudent.

Q. WHY ARE OPTIONS CONTRACTS AN UNECONOMIC FORM OF HEDGING FOR RATEPAYERS?

A. Option contracts are an inferior form of hedging relative to traditional hedging products, such as physical forward contracts and financial swaps. Because the NVPC forecast is deterministic, there are no benefits associated with such a contract included in revenue requirement. Yet, ratepayers still must pay substantially more in rates to cover the cost of the option premium—the fixed payment that must be made regardless of whether the option is in-the-money, or not. In contrast, a financial swap provides identical hedging protection against higher prices without the fixed option premium. Swaps are executed based on forward prices at the time of execution, without any need for a lump sum payment in addition to the fixed forward pricing. Because ratepayers can receive the same hedging benefit from a swap at lower cost, option contracts are inherently an imprudent form of hedging.

Q. ARE THERE CIRCUMSTANCES WHERE AN OPTION CONTRACT PROVIDES MORE BENEFIT THAN A SWAP?

A. Option contracts are always a more expensive form of hedging than a swap, except in circumstances when market prices decline by an amount more than the option premium. This is illustrated in Table 3, below.

Table 3
Financial Comparison of Option vs. Swap ($/MMBtu)

		Swap		Option		
Option Premium		-		0.50		
Fixed / Strike		6.00		6.00		
Market		Payout	Net Cost	Payout	Net Cost	Delta
	5.00	(1.00)	6.00	(0.50)	5.50	(0.50)
	5.25	(0.75)	6.00	(0.50)	5.75	(0.25)
	5.50	(0.50)	6.00	(0.50)	6.00	-
	5.75	(0.25)	6.00	(0.50)	6.25	0.25
Forward Price	6.00	-	6.00	(0.50)	6.50	0.50
	6.25	0.25	6.00	(0.25)	6.50	0.50
	6.50	0.50	6.00	-	6.50	0.50
	6.75	0.75	6.00	0.25	6.50	0.50

The illustration in Table 3 compares the net hedged cost of a swap contract to the net hedged cost of an option contract. Both contracts assume an identical fixed/strike price of 6.00/MMBtu, which represents the forward market price. While no option premium is required to purchase a swap at the forward market price, the option contract is assumed to be acquired with an option premium of $0.50/MMBtu. The Net Cost columns equal the cost of purchasing the underlying gas at the ultimate market prices, plus the financial settlements associated with the corresponding hedging instruments.

Under a swap contract, counterparties exchange a fixed monthly price with the floating index price. PGE is paid, or must pay, the difference between the fixed price and the actual market index price. As can be seen in Table 3, if prices go up, PGE receives a financial payment offsetting the increased cost of purchasing gas in the market; if prices go down, however, PGE must make a financial payment to its counterparty. PGE must ultimately procure the underlying gas at whatever the prevailing market price is at the time it is acquired. Accordingly, the net cost to PGE—*i.e.*, the cost of purchasing the gas, less the payout from the swap—is always \$6.00/MMBtu. With a swap, PGE pays this same net cost for natural gas regardless of the eventual market price.

The net hedged cost of an option, however, is more complicated. An option contract is asymmetrical and only pays out if market prices exceed a specified strike price, which in this case is assumed to be the forward market price of \$6.00. The assumed \$0.50/MMBtu option premium must be paid, regardless of whether the option is "in-the-money," or not, at the time of expiration. Thus, the option contract only provides net payout if the market price exceeds the strike price by an amount more than the option premium amount, or \$6.50/MMBtu in the example. Thus, if prices go up, ratepayers never pay more than \$6.50/MMBtu. This is in contrast to the swap, in which ratepayers never pay more than \$6.00/MMBtu. From this perspective, an option contract is an inferior form of hedging because ratepayers always pay more for an option if prices increase.

There are limited circumstances when an option can be more beneficial than a swap. If prices decline by an amount more than the option premium, the option will result in a lower total cost than a swap. In the above illustration, prices must decline to $5.50/MMBtu before the total hedged cost of gas from the option is less than the total hedged cost of gas from the swap. Thus, an option is only beneficial to ratepayers, relative to a swap, if prices decline materially.

Q. IS IT REASONABLE FOR RATEPAYERS TO PAY MORE IN THE AUT BASED ON THE PROSPECT THAT PRICES MIGHT DECLINE?

A. No. Hedging for price reductions is hedging in the wrong direction. Hedging is conducted to protect against the risk of higher-than-expected prices, not the other way around. By making the decision to enter into an option, rather than a swap, PGE is speculating that prices will decline in the forecast period by an amount sufficient to offset the option premiums, which is not prudent.

Q. DOES AN OPTION PROTECT PGE AGAINST PRICE SPIKES?

A. No. While we don't know the terms of the option PGE might propose, an option is typically settled based on average prices over the course of a month. Short-term price spikes that occur in scarcity events may have only minor impacts on the average pricing for the month. Therefore, PGE is better suited to purchase physical gas in order to alleviate the impact of price spikes and scarcity events.

Q. DOES AN OPTION SHIFT RISK OUT OF THE PCAM?

A. Yes. One of the reasons PGE shareholders may desire to enter into an option is that it shifts risk from the PCAM into the AUT. If the option premium is included in the AUT forecast, ratepayers are guaranteed to pay more through Schedule 125, by virtue of the option premiums, while only potentially benefiting in the PCAM if market prices decline. This results in a clear shifting of risk from the PCAM into the AUT. The AUT does not consider the benefit that might be derived from an option if market prices decline. Absent consideration of that benefit, the option contract is not only imprudent, but it is necessary to remove the extrinsic value of the contract from NVPC, consistent with the Commission's decision in UE 181.

Q. DOES THE COMMISSION HAVE A PRECEDENT OF EXCLUDING OPTION PREMIUMS FROM NVPC?

A. Yes. The Commission has a precedent of excluding the extrinsic value of option and super peak products from forecast NVPC. In Docket No. UE 181, PGE's 2007 power cost adjustment filing, the Commission found that "[w]ithout an extrinsic value adjustment, customer rates would include all of the costs, and none of the benefits of the contracts."[10] Since PGE has not actually executed any such contracts for the test period, it is impossible to know the degree of the extrinsic value at issue with the contracts it might execute. If the extrinsic value of the agreements is included in the forecast, ratepayers are irreparably harmed because PGE could have otherwise just acquired gas that would have provided a greater security of supply without increasing NVPC recovered through Schedule 125 rates. Therefore, an adjustment needs to be made to remove the extrinsic value from the forecast to hold ratepayers harmless.

Q. WHAT IS EXTRINSIC VALUE?

A. An option premium is also generally referred to as its extrinsic value, at least for an out-of-the-money option contract such as the one PGE models. The value of a financial instrument is the

[10] Docket No. UE 180 (cons.), Order 07-015 at 13 (Jan. 12, 2007).

sum of its intrinsic and extrinsic value. In the context of NVPC, which is based on current forward market prices, the intrinsic value can be viewed as the benefit of the instrument in the NVPC forecast. The intrinsic value represents the value that can be obtained from the instrument if exercised based on current market prices. For an in-the-money option, the intrinsic value represents the difference between the market price and the strike prices. For an out-of-the-money option, there is no intrinsic value.

The extrinsic value, on the other hand, is the value of everything else, including the option premium. In this case, the terms for the placeholder contract are not known. Since PGE does not model any benefits from the contract, it can be assumed that it is an out-of-the-money contract and that the entire option premium is an extrinsic value.

Q. IS IT APPROPRIATE TO INCLUDE THE EXTRINSIC VALUE OF AN OPTION CONTRACT IN NVPC?

A. No. Regardless of the prudence of the placeholder option contract PGE models, the entire option premium is appropriately removed from PGE's forecast under the precedent established in Docket No. UE 181 identified above.

VI. RELIABILITY CONTINGENCY EVENT

Q. WHAT HAS PGE FORECAST WITH RESPECT TO A RELIABILITY CONTINGENCY EVENT?

A. PGE included a $[redacted] adjustment to NVPC in connection with responding to a contingency event in the forecast period. I recommend this amount be excluded from the NVPC forecast. The AUT is based on a deterministic forecast of median, or normal, conditions. It does not include either the costs when system conditions are constrained or the costs when system conditions are relaxed. Therefore, forecasting a cost associated with responding to a contingency event is one-sided because PGE does not address the benefit of conditions when they are favorable. In addition, PGE's calculation of the cost of a contingency event is flawed in many ways.

Q. WHY IS PGE'S ADJUSTMENT ONE-SIDED?

A. In considering the cost of contingency events, it is also necessary to consider the other side of the distribution, corresponding to beneficial system conditions, such as oversupply events. Based on information provided in PGE's response to AWEC Data Request 81, there were [redacted] hours in which there were negative Mid-C market prices over the period 2020 through 2023. In those hours, PGE was basically being paid to serve its net load requirements. From this perspective, it is not appropriate to include the cost of contingency events in NVPC, without considering the corresponding benefits of the oversupply scenario.

Q. DO YOU AGREE WITH PGE'S CALCULATION OF THE COST OF CONTINGENCY EVENTS?

A. No. PGE compiled a plethora of different cost items in its calculation of the cost of responding to contingency events. PGE's calculations, however, are flawed in at least two different ways. First, the calculation assumes that incremental reserves will be necessary to be held on Beaver, when contingency reserves are already being considered in the reserve forecast assumed in the MONET model. Second, PGE did not correspondingly reduce the amount of reserve held in the MONET model when the contingency event was called. When a contingency event is called, PGE can dispatch resources being held in reserve, which produce power in lieu of purchasing high priced power. Accordingly, calling a contingency event will typically reduce power costs in high-cost days because it frees up generation resources. Given the onesidedness of PGE's adjustment and these issues with its calculation, I recommend that this adjustment be removed from NVPC.

VII. THERMAL PLANT PARAMETERS

a. EIM Master File Parameters

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH PGE'S THERMAL PLANT CHARACTERISTICS?

A. In AWEC Data Request 182, PGE was requested to provide the Western EIM master files submitted over calendar year 2022. PGE only provided one master file that was submitted on December 7, 2022. It is unclear at the time of this writing if there were other files from 2022 that were omitted from PGE's response. In review of those files, there are several material discrepancies between the plant parameters reported to the EIM and those used in MONET. My review was focused primarily on the plant capacities. Highly Confidential Table 4 details several of the discrepancies.

Highly Confidential Table 4
December Maximum Capacities – MONET vs. EIM Master File

	PGE MONET	EIM Master File
Beaver	[redacted]	
Port Westward 1		
Port Westward 2		
Carty		

As can be seen from Highly Confidential Table 4, the maximum outputs for Carty, Port Westward 1, and Port Westward 2 are [redacted] in the EIM master file than in the MONET model. Beaver is also [redacted], but not by the same magnitude as the other resources.

Q. WHAT IS THE IMPACT OF MODELING THE MAXIMUM CAPACITIES FROM THE EIM MASTER FILE?

A. Modeling the capacities identified above results in a $[redacted] reduction to NVPC. Since the master file was submitted in early December 2022, I have assumed the plant capacities to be a December value and shaped the remainder of the months using the same proportions as PGE's filing.

Q. IS THE HISTORICAL DISPATCH OF THE PLANTS CONSISTENT WITH THE INFORMATION REPORTED TO THE EIM?

A. Yes. Carty, instance, had hourly generation as high as [redacted] MWh in the historical data PGE provided in its Minimum Filing Requirements. Port Westward 1 had hourly generation as high as [redacted] MWh.

Q. WHAT DO YOU RECOMMEND?

A. There is no reason for the thermal plant parameters included in the MONET model to be different than the actual plant dispatch parameters reported to the EIM. Accordingly, I recommend PGE explain the differences in plant parameters identified above in its Rebuttal Testimony. For purposes of this testimony, I have assumed an adjustment reflecting the plant parameters in Highly Confidential Table 4.

b. <u>Beaver Cycling</u>

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO BEAVER DISPATCH?

A. In MONET, PGE modeling parameters for Beaver do not correspond to how the plant has historically been dispatched. Accordingly, I propose an adjustment to those parameters based on the observed dispatch patterns of the plant.

Q. HOW DOES PGE MODEL BEAVER CYCLING IN MONET?

A. PGE models Beaver as being required to cycle after running a certain number of hours, depending on the month. [redacted].

Q. IS PGE'S MODELING CONSISTENT WITH HOW BEAVER IS ACTUALLY DISPATCHED?

A. No. In actual operations, Beaver runs for extended periods of time without cycling. In **Confidential Exhibit AWEC/105**, I provide duration information surrounding Beaver's cycling profile compared to PGE's assumption in MONET. As can be seen, PGE's modeling assumptions surrounding Beaver cycling are not accurate in comparison to the historical data.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the 90th percentile cycling length identified in Exhibit AWEC/105 be used as the cycling limits modeled in MONET. This value was further adjusted for start-up and shut-down times.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. This modification produces an $[redacted] reduction to NVPC.

c. <u>Carty Outage Rate</u>

Q. PLEASE DISCUSS THE ISSUE YOU HAVE IDENTIFIED RELATED TO CARTY OUTAGE RATES.

A. In Docket UE 406, PGE's 2022 Power Cost Adjustment Mechanism, parties filed Joint Testimony demonstrating that an outage at Carty was the result of imprudent actions on behalf of PGE. That proceeding settled with a $1,750,000 black box adjustment to PGE's power cost variance. In response to AWEC Data Request 151, however, PGE confirmed that it did not adjust the Carty outage rate for this imprudent outage.

Q. IS IT APPROPRIATE TO INCLUDE THE 2021 CARTY OUTAGE IN PGE'S NVPC FORECAST?

A. No. The outage was the result of imprudent operations, which were described in Joint Testimony in Docket UE 406. Further, the outage is not the result of normal operating conditions and is appropriately removed as an abnormal outage. Accordingly, I recommend that the effects of the 2021 outage be removed from the Carty forced outage rate used to establish the 2024 NVPC forecast.

Q. WHAT IS THE IMPACT OF REMOVING THE 2021 OUTAGE

A. Removing the 2021 outage from the Carty forced outage rate calculation reduces NVPC by $[redacted].

VIII. BPA WHEELING

Q. WHAT BPA WHEELING ISSUES HAVE YOU IDENTIFIED IN PGE'S FILING?

A. In the stipulation in the 2023 AUT, parties agreed to special treatment for two items related to BPA's transmission rates. First, in Paragraph 9(a)(iv), PGE agreed to return the benefit of a potential BPA Reserves Distribution Clause ("RDC") in this docket.[11] Second, in Paragraph 9(a)(iii), PGE also agreed to defer and return, in this docket, the benefit or cost associated with differences between the assumed and final BP-24 transmission rates.[12] BPA has since issued a transmission RDC, and pursuant to a pre-filing settlement, BPA has also agreed to hold BP-24 transmission rates flat relative to BP-22 rate levels. PGE did not consider these items in its

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11 Docket No. UE 402, Order No. 22-427, Stipulation Appendix A, at 6 (Nov. 1, 2022).

12 *Id.*

filing, and considering the 2023 AUT settlement, they are appropriately considered in this docket. In addition, PGE did not update the going-forward BPA wheeling rates for the BP-24 rate case settlement, a correction which also needs to be applied to PGE's wheeling rate forecast.

a. <u>2023 AUT Stipulation: BPA 2023 Reserves Distribution Clause</u>

Q. PLEASE PROVIDE BACKGROUND ON THE 2023 AUT STIPULATION PROVISION RELATED TO THE RDC.

A. In the 2023 AUT, AWEC filed testimony discussing the mechanics of BPA's Reserves Distribution Clause, which provides a framework for BPA to refund excess reserves to power and transmission customers in certain circumstances.[13] AWEC noted that, given BPA's reserve levels at that time, BPA was likely to issue a RDC to transmission customers for fiscal year 2022, a decision which BPA would announce after the final update in the 2023 AUT. Accordingly, AWEC recommended the benefit of such an RDC be considered after the final NPC update, as a separate adjustment in the 2023 AUT. PGE opposed AWEC's recommendation, stating that BPA was unlikely to issue an RDC.[14] In settlement, however, Parties agreed that the benefit of a potential RDC, if issued, would be deferred and returned to ratepayers in this docket.

Q. DID BPA ISSUE A TRANSMISSION RDC IN 2022?

A. Yes. On December 15, 2022, BPA formally announced a transmission RDC in the amount of \$63,100,000.[15] Approximately, \$12,900,000 of that amount was to be returned to transmission

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[13] Docket No. UE 402, AWEC/100 Mullins/15:7-16:8.

[14] UE 402/PGE/300 Lucas – Outama – Cristea/24:1-2; 16-18.

[15] Bonneville Power Administration, Fiscal Year 2022 Transmission Reserves Distribution Clause Final Decision (Dec. 15, 2022).

customers through a reduction in transmission rates over the ten-month period December 2022 through September 2023. The remainder of the RDC was to be applied to cover other cost items, including towards holding BP-24 rates flat relative to BP-22 rates.

Q. WHAT IS THE IMPACT OF THE RDC ON PGE'S WHEELING COSTS?

A. In response to AWEC Data Request 71, PGE provided a workpaper detailing the reduction in wheeling rates resulting from the 2023 RDC. That workpaper showed that the RDC will result in a [redacted]% reduction to BPA transmission rates over the ten-month period December 1, 2022 through September 30, 2023. In response to AWEC Data Request 71, Highly Confidential Attachment C PGE calculated savings of $[redacted] in connection with the 2023 RDC. This calculation, however, was in error. It assumed the reduced RDC transmission rates would be in effect for 12 months, not the 10-month period BPA approved. Based on the transmission demands included in the final NVPC update in the 2023 AUT, my calculation is the transmission RDC will result in $[redacted] of savings to PGE.

b. <u>2023 AUT Stipulation: BP-24 Wheeling Rates</u>

Q. WHAT DID PGE ASSUME WITH RESPECT TO BP-24 WHEELING RATES IN THE 2023 AUT?

A. In its filing in the 2023 AUT, PGE had forecast an approximate [redacted]% increase to BPA wheeling rates beginning October 1, 2023 corresponding to the rate effective date of the BP-24 rate case. In testimony, AWEC recommended that PGE's assumed BP-24 increase be removed from the 2023 NVPC forecast because it was not known and measurable.[16] In response, PGE argued that a rate increase was likely.[17] In settlement, however, parties agreed to treat the BP-24 rate

16 Docket No. UE 402 AWEC/100 Mullins/14:16-18; 15:1-3.
17 UE 402/PGE/300 Lucas – Outama – Cristea/21:1-12.

increase in a manner similar to the 2023 RDC, deferring the difference in BP-24 wheeling expenses relative to the BP-24 transmission rate increase assumed in PGE's filing.

Q. DID BPA PROPOSE AN INCREASE TO TRANSMISSION RATES IN THE BP-24 RATE CASE?

A. No. On December 2, 2022, BPA filed its Initial Proposal in the BP-24 rate case. The BP-24 Initial Proposal was based on a pre-filing settlement reached between BPA and parties, including PGE and AWEC. In the pre-filing settlement, parties agreed to keep transmission rates flat, with no changes, relative to BP-22 rates. This agreement was made in part by agreeing that some of the available RDC funds would be used to offset a potential rate increase. No party is opposing the rates included in the BP-24 pre-filing settlement.

Q. WHAT IS THE DEFERRED IMPACT OF THE BP-24 SETTLEMENT IN THIS DOCKET?

A. Based on the transmission billing determinants assumed in PGE's final update, the impact of the settled BP-24 transmission rates is a $[redacted] reduction to wheeling expenses. In response to AWEC Data Request 71, Highly Confidential Attachment C, PGE calculated $[redacted] of deferred savings in connection with the BP-24 settlement. This calculation, however, also was in error. It appears that PGE did not remove the rate increase it had assumed for scheduling services.

c. <u>BPA 2024 Wheeling Expenses</u>

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO THE BPA WHEELING RATES PGE ASSUMED FOR CALENDAR YEAR 2024?

A. Beginning October 1, 2024, PGE forecast an increase to BPA wheeling rates. BPA's transmission rates, however, are adjusted through a biennial rate case process with the next potential rate change on October 1, 2025. Thus, there is no circumstance in which BPA's rates will increase on October 1, 2024. Further, as noted above, BPA and parties entered into a pre-filing settlement, in which transmission rates were to remain unchanged in the BP-24 rate case, with rate effective October 1, 2023. Thus, the October 1, 2024 wheeling rate increase PGE assumed in MONET is not appropriate.

Q. WHAT BPA RATES DID PGE ASSUME IN THIS DOCKET?

A. PGE used the same transmission rates it had assumed in the 2023 AUT for calendar year 2023, including the [redacted]% fourth quarter rate increase. This may have been an oversight. It is possible PGE overlooked updating BPA transmission rates in its filing. For example, between January 1, 2024 and September 30, 2024, PGE linked to the a cell referencing BP-22 rates, even though BP-24 rates will have already gone into effect, albeit with no rate increase, on October 1, 2023.

Q. IS THERE ANY JUSTIFICATION FOR INCLUDING THE FOURTH QUARTER INCREASE TO TRANSMISSION RATES?

A. No. There is no justification for PGE to forecast an increase to BPA transmission rates in calendar year 2024. Accordingly, I recommend it be removed. Removing this erroneous BPA rate increase will result in a $[redacted] reduction to NVPC.

IX. BIGLOW GENERATION

Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO BIGLOW'S GENERATION?

A. It was well documented in the press that PGE had wind turbine failures at its Biglow wind facility in 2022. An article in the Oregonian discussing the incidents and PGE's response is attached as **Exhibit AWEC/106**.

Q. HOW DO YOU RECOMMEND HANDLING THOSE FAILURES IN THIS CASE?

A. AWEC recommends that 2022 be excluded from the capacity factor calculation for Biglow. The abnormal events that occurred in 2022 were not only the results of imprudence, but not indicative of the plant operations going forward.

Q. WHAT IS THE IMPACT OF EXCLUDING 2022 FROM BIGLOW'S CAPACITY FACTOR CALCULATION?

A. Excluding 2022 from Biglow's capacity factor calculation produces a $[redacted] reduction to NVPC.

X. BALANCING ADJUSTMENT

Q. PLEASE EXPLAIN THE BALANCING ADJUSTMENT IN CONFIDENTIAL TABLE 1.

A. Each of the NPC impacts in this testimony were calculated as one-off adjustments, without considering the impacts of any other adjustments. This was done to isolate the impacts of individual modeling changes, without having the impacts skewed by the order in which the adjustment calculations were performed. There are, however, counterbalancing impacts between different adjustments. The impact of the Carty outage rate adjustment, for example, is different if one uses the higher maximum capacity from the EIM master file than if one uses the maximum capacity from PGE's filing. As another example, allowing for longer cycling of Beaver has a greater impact if reserve allocations are corrected in the downward flexibility reserve adjustment. To account for these counterbalancing impacts, as a last step in my modeling, a MONET model run was prepared that consolidates all of the adjustments described in testimony. The balancing adjustment is the difference between the sum of the individual adjustments and the consolidated MONET model study. In this case, the consolidated study resulted in an additional $[redacted] reduction to NVPC due to the nature of the adjustments at issue.

Q. DOES THIS CONCLUDE YOUR OPENING NVPC TESTIMONY?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/101

QUALIFICATION STATEMENT OF BRADLEY G. MULLINS

MW Analytics
ENERGY & UTILITIES

Bradley Mullins
Principal Consultant
brmullins@mwanalytics.com

MW Analytics is the professional practice of Bradley Mullins, a consultant and expert witness that represents utility customers in regulatory proceedings before state utility commissions throughout the western United States. Since starting MW Analytics in 2013, Mr. Mullins has sponsored expert witness testimony in over 100 regulatory proceedings on a variety of subject matters, including revenue requirements, regulatory accounting, rate development, and new resource additions. MW Analytics also assists clients through informal regulatory, legislative and energy policy matters. In addition to providing regulatory services, MW Analytics also provides advisory and other energy consulting services.

Education

- Master of Accounting, Tax Emphasis, University of Utah
- Bachelor of Finance, University of Utah
- Bachelor of Accounting, University of Utah

Relevant Prior Experience

PacifiCorp, Portland, OR: Net Power Cost Consultant 2010 – 2013

- Analyst involved in power cost modeling and forecasting
- Responsible for preparing power cost forecasts, supporting testimony for regulatory filings, preparing annual power cost deferral filings, and developing qualifying facility avoided cost calculations

Deloitte, San Jose, CA: Tax Senior 2007 – 2009

- Staff accountant responsible for preparing corporate tax returns for multinational corporate clients and partnership returns for hedge fund clients
- Joined to national tax practice specializing research and development tax credit studies

Recent Regulatory Appearances

Docket	Party	Topics
In re the Application of Intermountain Gas Company for Authority to Increase Its Rates and Charges for Natural Gas Service in the State of Idaho, Id.PUC Case No. INT-G-22-07.	Alliance of Western Energy Consumers	Revenue Requirement
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the fourth amendment to its 2021 Joint Integrated Resource Plan, PUC Nv. Docket No. 22-11032.	Caesars Enterprise Services, LLC; MGM Resorts International; Nevada Resorts Association	Resource Planning
In re Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the Third Amendment to its 2021 Joint Integrated Resource Plan., PUC Nv. Docket No. 22-09006.	Caesars Enterprise Services, LLC; MGM Resorts International; Nevada Resorts Association	Transportation Electrification

Docket	Party	Topics
In re Portland General Electric Company, Advice No. 22-18 New Schedule 151 Wildfire Mitigation Cost Recovery, Or.PUC Docket No. UE 412.	Alliance of Western Energy Consumers	Regulatory Accounting
In re PacifiCorp, Automatic Adjustment Clause for Wildfire Protection Plan Costs, Or.PUC Docket No. UE 407.	Alliance of Western Energy Consumers	Regulatory Accounting
In re Portland General Electric Company, Application for Authority to Amortize Deferred Amounts Related to 2020 and 2021 Wildfire and Ice Storm Emergency Events, Or.PUC Docket No. UE 408.	Alliance of Western Energy Consumers	Regulatory Accounting
In re PacifiCorp 2021 Power Cost Adjustment Mechanism, Or.PUC Docket No. UE 404.	Alliance of Western Energy Consumers	Power Cost Deferral
In re Portland General Electric Company, 2021 Annual Power Cost Variance Mechanism, Or. PUC UE 406	Alliance of Western Energy Consumers	Power Cost Deferral
In re Portland General Electric Company, Application Regarding Amortization of Boardman Deferral, Or.PUC Docket No. UE 410.	Alliance of Western Energy Consumers	Regulatory Accounting
In re the application of Sierra Pacific Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, PUC Nv. Docket No. 22-06014.	Smart Energy Alliance and Caesars Enterprise Services, LLC	Revenue Requirement
In re the Application of Dominion Energy Utah to Increase Distribution Rates and Charges and Make Tariff Modifications Ut.PSC Docket No. 22-057-03.	Nucor Steel-Utah	Cost of Service, Rate Spread and Rate Design
In re Joint Application of Nevada Power Company d/b/a NV Energy ("NPC") and Sierra Pacific Power Company d/b/a NV Energy ("SPPC") for approval to merge into a single corporate entity, to transfer Certificates of Public Convenience and Necessity ("CPC") 685 Sub 20, 688, and 688 Sub 6 from SPPC to NPC, and to consolidate generation assets, PUC Nv. Docket No. 22-03028.	Wynn Las Vegas, LLC and Smart Energy Alliance	Merger
In re Puget Sound Energy Requests for a General Rate Revision, Wa.UTC Docket. UE-220026 (cons.).	Alliance of Western Energy Consumers	Revenue Requirement
In re Northwest Natural Gas Company, dba, NW Natural, Updated Depreciation Study Pursuant to OAR 860-027-0350, Or.PUC Docket No. UM 2214	Alliance of Western Energy Consumers	Power Cost Modeling
In re Portland General Electric Company, 2023 Annual Update Tariff, Schedule 125, Or.PUC Docket No. UE 402.	Alliance of Western Energy Consumers	Revenue Requirement / Cost of Service
In re PacifiCorp d.b.a Pacific Power, Request for a General Rate Revision, Or.PUC Docket No. UE 399.	Alliance of Western Energy Consumers	Revenue Requirement
In re the Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of the cost recovery of the regulatory assets relating to the development and implementation of their Joint Natural Disaster Protection Plan., PUC NV. Docket No. 22-03006.	Alliance of Western Energy Consumers	Single-Issue Rate Filing
In re PacifiCorp d.b.a. Pacific Power, 2023 Transition Adjustment Mechanism, Or.PUC Docket No. UE 400.	Alliance of Western Energy Consumers	Power Cost Modeling
In re Cascade Natural Gas Corporation, Request for a General Rate Revision, Wa.UTC Docket No. UG-210755	Alliance of Western Energy Consumers	Revenue Requirement / Cost of Service

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/102

PGE RESPONSES TO DATA REQUESTS

April 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 070
Dated March 24, 2023

Request:

Reference Monet, Tab "PC Input," Cell "L1418":

a. Please explain why PGE did not use the settled BP-24 transmission rates.

b. Please quantify the impact of using the settled BP-24 transmission rates and provide workpapers supporting the calculation.

Response:

a. PGE did not use settled BP-24 transmission rates because these rates have not been approved yet through an Administrator's Final Record of Decision (ROD). PGE will update 2024 BPA transmission rates pursuant to the Administrator's Final ROD, expected to be issued in July 2023.

b. Confidential Attachment 070-A provides the 2024 NVPC forecast MONET modeling run using the settled BP-24 transmission rates. Confidential Attachment 070-B provides the MONET steplog for PGE's initial 2024 NVPC forecast, adding a step to reflect the cost impact with using settled BP-24 transmission rates (see row 20, cell Q20).

   PGE will model the final BP-24 transmission rates as approved through the Administrator's Final ROD and include all supporting documentation in the MONET October update filing or in PGE's July MONET update if a ROD is issued before July 2023.

Attachments 070-A and 070-B are protected information subject to Protective Order No. 23-039.

April 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 071
Dated March 24, 2023

Request:

In Paragraph 9(a)(ii) of the Stipulation in UE 402, PGE agreed to return the benefit of a potential BPA Reserves Distribution Clause ("RDC") in this docket. BPA issued a $63.1 million transmission RDC in December 2022. Please quantify the amount of the deferred RDC benefit due to customers and provide workpapers supporting the calculation.

Response:

On December 15, 2022, BPA published a letter providing that the agency will apply $12.9 million as a divided redistribution to reduce fiscal year 2023 transmission rates.[1] As part of the dividend redistribution, BPA applied a credit percentage of 1.46% to BPA transmission rates for the period December 2022 – September 2023. Attachment 071-A provides BPA's adjusted transmission rates to reflect the transmission dividend distribution.

Confidential Attachment 071-B provides the final MONET model run for year 2023 with adjusted BPA transmission rates for the period January 1, 2023 – September 30, 2023. Additionally, the final MONET model run for year 2023 was also adjusted to include settled BP-24 rates for the period October 1, 2023 – December 31, 2023.

Confidential Attachment 071-C provides the steplog for the additional two modeling steps described above added to the final 2023 AUT modeling steplog. The cost impact associated with the BPA RDC is provided in row 108. The cost impact associated with using settled BP-24 transmission rates is provided in row 109.

Attachments 071-B and 071-C are protected information subject to Protective Order No. 23-039.

[1] https://www.bpa.gov/-/media/Aep/rates-tariff/rate-adjustments/2022-2023-adjustments/Administrators-Letter--Transmission-RDC-final-decisionsigned.pdf

April 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 072
Dated March 24, 2023

Request:

In Paragraph 9(a)(iii) of the Stipulation in UE 402, PGE also agreed to defer and return, in this docket, the benefit/or cost associated with differences between the assumed and final BP-24 transmission rates. BPA has since filed the BP-24 transmission rate case and pursuant to a settlement agreement to which PGE was a party, BPA proposed no changes to transmission rates. Please calculate the impact of the benefits deferred under the referenced paragraph, assuming the BP-24 settlement agreement is approved. Please also provide workpapers supporting PGE's calculations.

Response:

See PGE's response to AWEC Data Request No. 071.

April 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 081
Dated March 24, 2023

Request:

Please provide actual hourly, day-ahead electric prices for Mid-Columbia, and the California Oregon Border over the period January 1, 2020 through March 31, 2023.

Response:

Confidential Attachment 081-A provides the requested information.

Attachment 081-A is protected information subject to Protective Order No. 23-039.

April 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 093
Dated March 24, 2023

Request:

Please detail the total MWh of hydro spill by resource over the period January 1, 2020 through December 31, 2022.

Response:

PGE objects to this request on the basis that it is vague. Subject to and without waving this objection, PGE responds as follows:

PGE does not track hydro spill data or perform analysis to determine potential MWh of hydro spills at PGE's West Side Hydro projects or Pelton-Round Butte.

Confidential Attachment 093-A provides PGE's share of hydro spills at the Mid-C hydro projects contracted by PGE (i.e., Rocky Reach, Douglas Wells, Wanapum, and Priest Rapids). Please note that the data is provided to PGE by the hydro project owner/operator and the units are in MWh for PGE's share at Rocky Reach and Douglas Wells, and in cubic feet per second (cfs) for PGE's share at Wanapum and Priest Rapids.

Attachment 093-A is protected information subject to Protective Order No. 23-039.

April 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 095
Dated March 24, 2023

Request:

For each hour over the period January 1, 2020 through December 31, 2022, please identify the amount of reserves held by plant and reserve type (i.e., contingency, regulation, frequency, and day-ahead / hour-ahead uncertainty).

Response:

Confidential Attachment 095-A provides the hourly spinning reserve and regulation reserve submitted by PGE to the CAISO EIM at the plant level from January 1, 2020 through December 31, 2022. It also provides the total non-spinning reserve and total contingency reserve for the requested period.
The data are retrieved from the PCI system and the PI system, a real-time information telemetry system with complex interpolations from high frequency data to hourly values. The data retrieved from the PI system is in its raw format and has not been scrubbed by PGE in confidential Attachment 095-A.

PGE does not explicitly track reserves held for frequency response and day-ahead/hour-ahead uncertainty. Rather, PGE tracks these reserves at the Balancing Authority level.

For frequency response reserves, PGE's Balancing Authority currently requires a minimum of -25.2MW/0.1Hz of frequency responsive reserves.

For day-ahead uncertainty reserves, formulaically, PGE applies the same parabolic curve in PGE's day-ahead optimization tool as the MONET modeling for Day Ahead Forecast Error (DAFE). See detail regarding the DAFE modeling in MFRs, "Vol 8 - Ancillary Services\DAFE and HAFE".

For hour-ahead uncertainty, PGE ultimately follows CAISO's uncertainty requirement. See PGE's response to AWEC Data Request No. 096 with detailed hour-ahead uncertainty requirement.

Attachment 095-A is protected information subject to Protective Order No. 23-039.

April 7, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 096
Dated March 24, 2023

Request:

Please detail the amount of upwards and downwards flexible ramping reserves requirements (i.e., Uncertainty Requirements) applied by the EIM for PGE for each available time interval over the period January 1, 2020 through December 31, 2022.

Response:

Confidential Attachment 096-A provides the amount of upwards and downwards flexible ramping reserves requirements (i.e., Uncertainty Requirements) applied by the CAISO EIM (Energy Imbalance Market) to PGE for each available time interval over the period January 1, 2020 through December 31, 2022.

Attachment 096-A is protected information subject to Protective Order No. 23-039.

April 24, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 151
Dated April 10, 2023

Request:

Reference #CartyFORCalc_2023AUT: Please explain how the outage identified in Joint Parties' testimony in Docket UE 406 was handled in calculating the outage rates in the referenced file.

Response:

The referenced outage is included in the four-year rolling average of actual forced outages used to determine the test year forced outage rate for Carty.

May 8, 2023

To: Jesse Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 416
PGE Response to AWEC Data Request 182
Dated April 18, 2023

Request:

Please provide the plant master files reported to the Western EIM for each of PGE's generation resources over calendar year 2022.

Response:

PGE objects to this request on the basis that it is vague. Subject to and without waiving this objection, PGE responds as follows:

Highly Confidential Attachment 182-A provides the PGE plant master file reported to the Western EIM on December 7, 2022.

Attachment 182-A is highly confidential information subject to Modified Protective Order No. 23-138.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
	)
Request for a General Rate Revision.	)
	)

EXHIBIT AWEC/103

POWEREX MID-COLUMBIA WSPP PRODUCT DEFINITIONS

Powerex

Powerex Corp.
1300 - 666 Burrard Street
Vancouver, BC, Canada
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POWEREX CORP.

WSPP SCHEDULE C FIRM ENERGY

MID-COLUMBIA (MIDC) PRODUCTS – TERMS AND POLICY

Effective: December 28, 2022, for transactions with delivery on or after January 1, 2023

The objective of this Terms and Policy document is to be transparent with, and clearly communicate to, counterparties, Powerex's requirements when transacting WSPP Schedule C Firm Energy at Mid-Columbia (MIDC). In particular, Powerex has observed two relatively recent market developments:

(i) a higher incidence of sellers attempting to meet firm energy commitments with resources and transmission that are not sufficiently reliable to assure delivery, and

(ii) uncertainty regarding Washington's new cap and invest program and application thereof to transactions at MIDC, which is in Washington, as reporting requirements and compliance costs may be imposed on one party based on the actions and decision-making of the other party.

Powerex believes clarity is beneficial for both parties to a transaction regarding (i) the quality of supply and transmission associated with a WSPP Schedule C Firm Energy delivery, and (ii) the reporting requirements and compliance costs under Washington and other cap and trade/cap and invest programs. To achieve this, Powerex will be transacting WSPP Schedule C Firm Energy for delivery on or after January 1, 2023, by seeking to clearly define three distinct WSPP Schedule C Firm Energy products, each with terms and conditions addressing the above-referenced market developments:

1. WSPP Schedule C Firm Energy – WA CCA Compliant
2. WSPP Schedule C Firm Energy – No Washington Sink
3. WSPP Schedule C Firm Energy – Specified Source Energy from one of the following sources:
   a. A carbon free source (assigned emissions factor of 0.00 TCO2e/MWh)
   b. An asset-controlling supplier

Product 1 (WA CCA Compliant) is the standard WSPP Schedule C Firm Energy MIDC product transacted on ICE, with the mutual understanding between the Seller and the Purchaser that such product is WA CCA Compliant. To the extent a Seller does not agree that the standard product transacted on ICE is a WA CCA Compliant product, Powerex will no longer transact the standard product with that counterparty on ICE. Powerex expects to transact Product 2 and Product 3 through brokers (off ICE) or bilaterally.

Appendix A provides a backgrounder on the policy considerations underlying Powerex's position and response to the above market developments.

Appendix B provides a detailed description and terms and conditions for each Product.

This Terms and Policy document may be updated from time to time as market rules or circumstances change. Powerex welcomes feedback on this Terms and Policy document. For general questions or comments please contact Powerex Cash Desk at cash.desk@powerex.com or 604-891-5007. For questions related to the contractual terms and conditions provided in this document, please contact Jonathan Gilhen at Jonathan.Gilhen@powerex.com or 604-891-5063.

Powerex

APPENDIX A – POLICY BACKGROUNDER

PART 1: WSPP SCHEDULE C FIRM ENERGY – RELIABLE TRANSMISSION AND SOURCES

WSPP Service Schedule C Firm Energy is expected to provide reliable physical supply of power to the Purchaser. Service terms that require Seller to schedule the energy as firm power consistent with applicable reliability rules, requiring transactions be prescheduled (subject to any conditions agreed by schedulers) and the very narrow circumstances in which WSPP Schedule C Firm Energy may be interrupted, with or without damages, are all indicia of the expectation of reliable physical supply. Firm energy is predicated on Seller using reliable sources and reliable transmission such that Purchaser can be confident that the energy will be delivered as contracted. As such, it is imperative that Purchaser evaluates whether a schedule is likely to satisfy a firm energy obligation in advance of delivery rather than be forced to use liquidated damages as the sole remedy.

Powerex has identified two key criteria it expects all WSPP Schedule C Firm Energy will satisfy, as follows:

Criterion 1 – Reliable Transmission. WSPP Schedule C Firm Energy must be scheduled using sufficiently reliable transmission. Powerex reserves the right, at its discretion, to reject a schedule which uses non-firm transmission service that it deems to be at material risk of curtailment. Notwithstanding Powerex's acceptance of a schedule using lower quality transmission, any curtailment of non-firm transmission service will be considered a failure to deliver under the Agreement and subject to liquidated damages.

Criterion 2 – Reliable Sources. WSPP Schedule C Firm Energy purchases must be scheduled from sources that are capable of being reliably committed in the preschedule window for delivery during the hours and day(s) being prescheduled. Sources, which may include system resources, will meet this criterion if the Seller can commit in preschedule to reasonable assurance of the availability of sufficient available generating capacity—including necessary operating reserves— to enable firm delivery from the identified source during the hours and days being prescheduled.

Energy that is: (a) economically curtailable, (b) sourced from an organized market without a confirmed day-ahead market award, or (c) scheduled from a source without assurance of sufficient available committed capacity to support firm energy delivery for all days and hours of the prescheduled period does not satisfy this requirement. If a transaction for WSPP Schedule C Firm Energy does not meet the above criteria, Purchaser has the right to reject the schedule in advance.

Application of Criteria to Certain Sources/Resources

The following sources do not meet the criteria for WSPP Schedule C Firm Energy, either generally or in the circumstances described. However, if one of the specified exceptions below is satisfied the source may still be accepted.

Alberta

Alberta (AESO) does not have a day-ahead market, and therefore any upstream counterparty seeking to source a forward or day-ahead sale commitment to Purchaser from the AESO does not yet have a preschedule source, because it does not have a market award.

Further: AESO has awarded exports in real-time even if it has insufficient physical resources to support the total export quantity, export transactions are exclusively on opportunity service transmission, and AESO unambiguously does not provide any assurance of the firmness of the supply supporting export transactions from its market, all of which materially increase the risk of export or transmission curtailment.

Powerex

Exceptions: None.

CAISO

CAISO only considers an export from its service territory to be "high priority" if it is explicitly linked to an identified physical resource inside the CAISO service territory that does not have an RA obligation to California. Generic CAISO-sourced day-ahead exports that are not explicitly supported by an identified non-RA resource (generally referred to by the CAISO as "Low Priority Exports") are not guaranteed to be supported by sufficient physical resources to ensure delivery and are subject to higher curtailment risk in real-time. Low priority exports cannot, as a categorical matter, be relied upon for firm energy delivery. Furthermore, CAISO has made changes in recent years to its treatment of such low priority energy exports, including, among others, temporary FERC approval to reduce the priority of wheel-through and export schedules, and it has detailed its practice of curtailing energy exports in circumstances other than reliability events. All of the foregoing means that low priority generic CAISO-sourced energy is not capable of being committed in the preschedule window with confidence.

Exceptions:

Powerex is willing to accept generic CAISO-sourced energy (i.e., CAISO-sourced exports that are not explicitly supported by an identified non-RA resource) under the following specific conditions (both of which must apply):

- Seller offers the CAISO-sourced energy in a period where the CAISO has not issued a flex alert notice or posted any other communication or taken any other action indicating a potential supply insufficiency; <u>and</u>

- Seller commits to confirm by 2 pm on the prescheduling day that it has received a Residual Unit Commitment (RUC) schedule from CAISO to support the CAISO export.

SPP

Powerex understands that SPP considers a day-ahead cleared Export Interchange Transaction to be a firm commitment that is prioritized in a manner comparable to internal demand, with market processes that commit physical capacity to support those export transactions. Furthermore, Powerex understands that SPP will apply curtailments to exports on a pro-rata basis with internal demand during a capacity shortage in the SPP footprint. Absent emergency conditions, cleared day-ahead exports from SPP are generally supported by sufficient committed physical capacity within the SPP footprint and can be committed in the preschedule window.

Deliveries from SPP, however, require additional consideration of the transmission risks associated with scheduling energy from the Eastern Interconnection. First, transactions sourced from SPP must be scheduled across one of a small number of DC ties that face unique scheduling risks, including the potential for curtailment resulting from operating restrictions (e.g., DC tie operators may apply limitations to schedules to ensure net flows do not fall within an operating "deadband"). In addition, deliveries from SPP typically require several additional transmission segments to enable delivery to Mid-C or other western trading hubs, often across several WECC constrained flowgates that have historically been subject to real-time curtailments, particularly for short-duration, low-priority transmission service. These circumstances can result in deliveries from SPP facing a heightened risk of transmission curtailment relative to deliveries sourced from less remote locations.

Powerex will currently accept an SPP sourced sale as a source to meet a WSPP Schedule C Firm Energy delivery obligation in the preschedule timeframe under the following specific conditions:

- Seller offers the SPP sourced energy in a period where SPP has not issued an emergency notice or posted any other communication or taken any other action indicating supply insufficiency; <u>and</u>

Powerex

- Seller commits to submit a confirmed e-Tag by 2pm on the prescheduling day that:
  - reflects its cleared Day Ahead export awards for each hour; and
  - includes sufficiently reliable transmission service on all segments (including the DC path connecting the Eastern Interconnection with WECC)

PART 2: WASHINGTON CCA COMPLIANCE – MIDC TRANSACTIONS

Washington State's cap and invest program starts on January 1, 2023. The program, created pursuant to the Climate Commitment Act (CCA), adopts the WCI's first jurisdictional deliverer (FJD) approach for regulating electricity imports into Washington State. Generally, the FJD is the first entity in a scheduled electricity transaction over which the state has jurisdiction. The CCA states that where the transaction is scheduled with an e-tag, the electricity importer is "the purchasing-selling entity on the last segment of the tag's physical path with the point of receipt located outside the state of Washington and the point of delivery located inside the state of Washington."

The CCA includes a variety of exceptions to this approach that allocates the CCA reporting and compliance obligation to a different entity in the schedule. These exceptions are addressed in WAC 173-441-124.(2).(c) and (g) for supply from a Federal Power Marketing administration (BPA), Multi-Jurisdictional Electric Companies and Consumer Owned Utilities, and for entities importing to a designated scheduling point inside the balancing authority area of a Federal Power Marketing administration (BPA).

Under the FJD approach for imported electricity the CCA regulates the first entity in the physical path for which the Department of Ecology has jurisdiction. Until BPA elects to be bound by the CCA the FJD is the next purchase-selling entity in the physical path on the e-tag downstream of BPA. This modification has implications for a substantial number of transactions, given BPA's Balancing Authority Area connects to MIDC and BPA appears as the purchase-selling entity on many e-tags. As a result, buyers who would not otherwise be the FJD may incur liability under the cap and invest program.

Powerex

APPENDIX B – TERMS AND CONDITIONS

Product 1 –WSPP Schedule C Firm Energy – WA CCA Compliant

Description: WSPP Schedule C Firm Energy MIDC product transacted on ICE, with the mutual understanding that such product is WA CCA Compliant.

Terms and Conditions: The Parties agree the following terms and conditions will apply to transactions for Product 1:

1. Seller is expected to use reliable transmission service to schedule energy to the delivery point. Purchaser reserves the right, at its discretion, to reject a schedule using non-firm transmission service that it deems to be at material risk of curtailment as per Section 5 below. In any event, an interruption of non-firm transmission service resulting in a failure to deliver energy will be considered non-performance and subject to damages provisions under this Agreement.

2. Seller must provide a source (which may include a system resource) in the preschedule window that: (i) is not subject to economic curtailment, (ii) has a confirmed day-ahead market award (if the source is or is within an organized market), (iii) has sufficient available generating capacity—including necessary operating reserves— in the preschedule window to reliably meet the day-ahead commitment. The following sources are not permitted:

    a. Alberta Electric System Operator (AESO)

    b. California Independent System Operator (CAISO), except as follows:
        i. Seller confirms it has an identified resource inside the CAISO service territory supporting the export that is not a Resource Adequacy Resource, or
        ii. if both of the following are satisfied:
            A. CAISO has not issued a flex alert notice or posted any other communication or taken any other action indicating supply insufficiency affecting the day(s) of delivery; and
            B. by 14:00 on the prescheduling day, seller confirms that it has received a Residual Unit Commitment (RUC) schedule from CAISO to support the CAISO export.

    c. Southwest Power Pool (SPP), except as follows:
        i. SPP has not issued an emergency notice or posted any communication or taken any action indicating supply insufficiency affecting the day(s) of delivery; and
        ii. Seller submits a confirmed e-Tag by 14:00 on the preschedule day that reflects its cleared day-ahead export awards from SPP for each hour.

3. Seller is responsible for all applicable reporting and compliance obligations under State of Washington's Climate Commitment Act (unless Purchaser is required to be the "electricity importer" under WAC 173-441-124.(2).(c)).

4. If the importer would be a federal PMA under (v) of WAC 173-441-124.(2).(c), then Seller is required to be the next PSE in the physical path of the e-Tag.

5. Purchaser will have the right to reject a schedule not complying with the above terms and treat the rejected schedule as a failure to schedule and deliver the energy as provided in this Confirmation. Seller may dispute Purchaser's rejection and damages claim in accordance with the Agreement's applicable dispute resolution provisions.

Powerex

Product 2 –WSPP Schedule C Firm Energy – No Washington Sink

Description: WSPP Schedule C Firm Energy that is not sunk in State of Washington.

Terms and Conditions: The Parties agree the following terms and conditions will apply to transactions for Product 2:

1. Seller is expected to use reliable transmission service to schedule energy to the delivery point. Purchaser reserves the right, at its discretion, to reject a schedule using non-firm transmission service that it deems to be at material risk of curtailment as per Section 4 below. In any event, an interruption of non-firm transmission service resulting in a failure to deliver energy will be considered non-performance and subject to damages provisions under this Agreement.

2. Seller must provide a source (which may include a system resource) in the preschedule window that (i) is not subject to economic curtailment, (ii) has a confirmed day-ahead market award (if the source is or is within an organized market), (iii) has sufficient available generating capacity—including necessary operating reserves— in the preschedule window to reliably meet the day-ahead commitment. The following sources are not permitted:

    a. Alberta Electric System Operator (AESO)

    b. California Independent System Operator (CAISO), except as follows:
        i. Seller confirms it has an identified resource inside the CAISO service territory supporting the export that is not a Resource Adequacy Resource, or
        ii. if both of the following are satisfied:
            A. CAISO has not issued a flex alert notice or posted any other communication or taken any other action indicating supply insufficiency affecting the day(s) of delivery; and
            B. by 2 pm on the prescheduling day, seller confirms that it has received a Residual Unit Commitment (RUC) schedule from CAISO to support the CAISO export.

    c. Southwest Power Pool (SPP), except as follows:
        i. SPP has not issued an emergency notice or posted any communication or taken any action indicating supply insufficiency affecting the day(s) of delivery; and
        ii. Seller submits a confirmed e-Tag by 14:00 on the preschedule day that reflects its cleared day-ahead export awards from SPP for each hour.

3. Seller will have the right to reject a day-ahead and real-time schedule that has a final sink in the State of Washington and treat the rejected schedule as a failure to schedule and receive the energy as provided in this Confirmation.

4. Purchaser will have the right to reject a schedule not complying with Section 1 or 2 above and treat the rejected schedule as a failure to schedule and deliver the energy as provided in this Confirmation.

5. Either party may dispute the other party's rejection and damages claim in accordance with the Agreement's applicable dispute resolution provisions.

Powerex

Product 3 –WSPP Schedule C Firm Energy – Specified Source Energy (Carbon-Free or ACS)

Description: WSPP Schedule C Firm Energy delivered to MIDC that is contingent on delivery from a source specified at the time of execution.

Terms and Conditions: The Parties agree the following terms and conditions will apply to transactions for Product 3:

1. Seller is expected to use reliable transmission service to schedule energy to the delivery point. Purchaser reserves the right, at its discretion, to reject a schedule using non-firm transmission service that it deems to be at material risk of curtailment as per Section 5 below. In any event, an interruption of non-firm transmission service resulting in a failure to deliver energy will be considered non-performance and subject to damages provisions under this Agreement.

2. "Applicable Cap and Trade Program" means any mandatory program implemented by a US State or Canadian Province requiring the reporting of emissions associated with generation or delivery of electricity and imposing compliance obligations in consequence thereof, including California's Cap and Trade Program (17 CA ADC Articles 2 and 5) and Washington's Cap and Invest Program (Ch. 70A.65 RCW and associated regulations and rulemaking), as applicable to the energy purchased and sold pursuant to this Confirmation.

3. This Confirmation provides for delivery of electric energy from the particular facility, unit, or asset-controlling supplier's system ("Source") designated in this Confirmation. As part of the product, Purchaser has the right to identify that the energy was generated by and attributable to the Source, including the source emissions factor associated with the Source.

4. For Sources other than asset-controlling supplier sources, Seller will provide Purchaser with Source meter data (or equivalent) if requested by Purchaser to support delivery of energy from the Source pursuant to this Confirmation and reporting, if required, under an Applicable Cap and Trade Program.

5. Purchaser may reject a schedule not complying with the above terms and treat such rejected schedule as a failure to schedule and deliver the energy as provided in this Confirmation. For each MWh of energy that Seller delivers from any source other than the Source, including unspecified market energy, Seller will pay Purchaser an amount determined by Purchaser in a commercially reasonable manner representing an estimate of the difference in compliance cost under the Applicable Cap and Trade Program between unspecified (or market) energy and specified energy from the Source having regard to, among other things, the most recent auction or ICE/OTC traded prices for allowances or other applicable compliance instruments. Seller may dispute Purchaser's rejection or damages claim in accordance with the Agreement's applicable dispute resolution provisions.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
	)
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Request for a General Rate Revision.	)
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EXHIBIT AWEC/104

PRODUCTION TAX CREDIT RATE FORECAST FOR 2024

PTC Inflation Adjustment Factor Calculations and PTC Rate Forecast

	Year	GDP Implicit Price Deflator Q1	Q2	Q3	Q4	AVG.	1992	Inflation Adjustment Factor Calculated	Actual	Delta	PTC Rate
	1992	119.80	120.60	121.20	121.80	120.90	120.90	1.0000	1.0000	-	1.5
	1993	123.30	124.00	124.50	124.90	124.20	120.90	1.0273	1.0273	-	1.5
	1994	125.00	125.90	126.50	126.90	126.10	120.90	1.0430	1.0430	-	1.6
	1995	106.70	107.30	107.80	108.30	107.50	100.00	1.0750	1.0750	-	1.6
	1996	109.00	109.50	109.90	110.30	109.70	100.00	1.0970	1.0970	-	1.6
	1997	111.71	112.22	112.62	113.05	112.40	100.00	1.1240	1.1240	-	1.7
	1998	112.32	112.56	112.84	113.04	112.69	100.00	1.1269	1.1269	-	1.7
	1999	103.83	104.19	104.46	104.98	104.37	91.70	1.1382	1.1382	-	1.7
	2000	106.10	106.73	107.15	107.65	106.91	91.84	1.1641	1.1641	-	1.7
	2001	108.65	109.21	109.82	109.75	109.36	91.84	1.1908	1.1908	-	1.8
	2002	110.14	110.48	110.76	111.21	110.65	91.84	1.2048	1.2048	-	1.8
	2003	105.15	105.43	105.85	106.16	105.65	86.39	1.2230	1.2230	-	1.8
	2004	107.25	108.09	108.48	109.06	108.22	86.39	1.2528	1.2528	-	1.9
	2005	110.91	111.62	112.53	113.49	112.14	86.39	1.2981	1.2981	-	1.9
	2006	114.95	115.89	116.42	116.89	116.04	86.39	1.3433	1.3433	-	2.0
	2007	118.75	119.52	119.83	120.61	119.68	86.39	1.3854	1.3854	-	2.1
	2008	121.51	121.89	123.06	123.21	122.42	86.39	1.4171	1.4171	-	2.1
	2009	109.69	109.69	109.78	109.88	109.76	76.53	1.4342	1.4342	-	2.2
	2010	109.95	110.49	111.05	111.15	110.66	76.53	1.4459	1.4459	-	2.2
	2011	112.40	113.12	113.84	114.08	113.36	76.60	1.4799	1.4799	-	2.2
	2012	114.60	115.04	115.81	116.07	115.38	76.60	1.5063	1.5063	-	2.3
	2013	106.11	106.26	106.78	107.20	106.59	70.64	1.5088	1.5088	-	2.3
	2014	107.66	108.23	108.60	108.64	108.28	70.57	1.5344	1.5336	0.00	2.3
	2015	109.10	109.67	110.03	110.29	109.77	70.57	1.5555	1.5556	(0.00)	2.3
	2016	110.63	111.26	111.65	112.21	111.44	70.57	1.5791	1.5792	(0.00)	2.4
	2017	112.75	113.03	113.61	114.27	113.42	70.57	1.6072	1.6072	-	2.4
	2018	109.37	110.27	110.68	111.22	110.38	67.33	1.6396	1.6396	-	2.5
	2019	111.47	112.19	112.66	113.04	112.34	67.33	1.6686	1.6687	(0.00)	2.5
	2020	113.42	112.82	113.84	114.37	113.63	67.33	1.6877	1.6878	(0.00)	2.5
	2021	116.12	117.92	119.71	121.71	118.37	67.28	1.7594	1.7593	0.00	2.6
	2022	124.17	126.91	128.27	129.51	127.21	67.28	1.8909			2.8
2023 Forecast	2023	130.787	*131.7986*	*132.818*	*133.8454*	*132.3123*	67.28	1.9667			***3.00***
		0.99%	*0.77%*	*0.77%*	*0.77%*	3.13%					
Zero Inflation	2023	129.508	*129.508*	*129.508*	*129.508*	*129.508*	0.00	1.9250			***2.90***
			0%	*0%*	*0%*	0.0%					

BEFORE THE

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UE 416

In the Matters of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY,	)
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Request for a General Rate Revision.	)
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EXHIBIT AWEC/105

BEAVER CYCLING HISTORY

(REDACTED)

Exhibit AWEC/105 contains Protected Information Subject to Modified General Protective Order No. 23-039 and has been redacted in its entirety.

BEFORE THE

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EXHIBIT AWEC/106

OREGONIAN ARTICLE DISCUSSING BIGLOW TURBINE FAILURES

Wind Bust

How an airborne blade exposed broader problems at PGE's flagship wind farm

Story by **TED SICKINGER**
Photography by **DAVE KILLEN**
The Oregonian/OregonLive

Aug. 27, 2022

In the waning days of January, a worker delivering fertilizer to a wheat farm in the rolling hills of Sherman County found some broken, industrial-size bolts on the ground near one of Portland General Electric's towering wind turbines.

He was puzzled because it stood to reason the bolts fell from the machine. But he didn't know if there was a problem or, if so, who to tell. So he picked up one, sent a snapshot to his co-worker, Kevin Massie, and used it as a paperweight while he documented the delivery.

A broken blade bolt found under a wind turbine at Biglow Canyon wind farm by a worker delivering fertilizer in late January. A day or two later, the turbine threw an eight-ton blade into a nearby field. (Courtesy Kevin Massie)

Massie arrived a day or two afterward to tow a delivery driver whose vehicle got stuck in the mud near the same turbine at Biglow Canyon. It was dark and windy. Nothing seemed out of the ordinary.

Hours later, at 2:11 a.m. Feb. 1, one of the turbine's three spinning blades launched into the night.

No one saw it. No one heard it. But it was evidently a violent affair.

The skinny blade, as tall as an 11-story building and weighing more than four Toyota Camrys, soared the full length of a football field. It plowed a furrow 4-feet deep in the wheat stubble where it eventually landed.

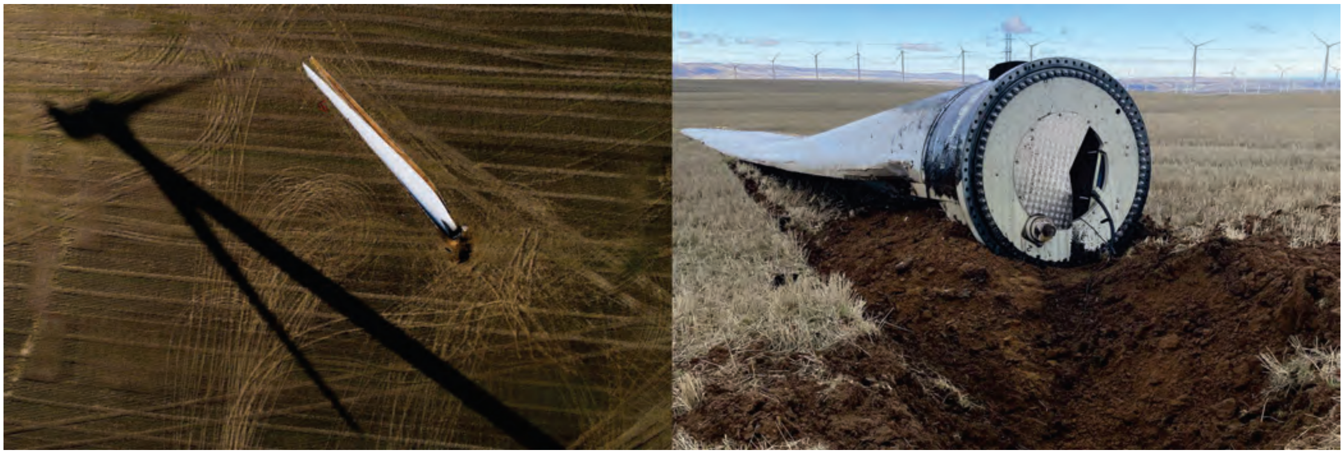
Heavy-duty bolts that once kept the blade fastened to the tower scattered around the turbine base like shrapnel, some spiked deep into the soil.

Broken blade bolts were scattered around turbine 71 at Portland General Electric's Biglow Canyon wind farm after the turbine threw a blade in the early hours of Feb. 1. Hours before the blade throw, a driver delivering fertilizer became stuck in close proximity to the turbine and had to be towed out. (Courtesy Kevin Massie)

"Someone could have been killed or badly injured," said Kathryn McCullough, whose husband, Kevin, farms under about half of Biglow Canyon's turbines – including the one that lost its blade.

The broken bolts preceding the incident weren't the only warning signs of problems at PGE's flagship wind facility, which opened 15 years ago amid a push to expand green energy technology in Oregon and nationally. But it took the so-called "blade liberation" for PGE to take urgent action at Biglow Canyon, one of Oregon's largest wind farms, shutting down all 217 turbines for testing and keeping some out of service for at least four months.

The dramatic episode in the rural landscape of the Columbia River Gorge represents a revealing, if concerning, inflection point in Oregon's two-decade history with the ubiquitous turbines that help fuel clean energy.



On Feb 1, turbine 71 at Portland General Electric's Biglow Canyon wind farm threw an eight-ton blade 100 yards into a nearby field, plowing a deep furrow in the ground where it landed. (Left, Dave Killen, right courtesy Kathryn McCullough)

Industry groups insist that wind farms are very safe and major malfunctions, such as blades flying off the turbines, are exceedingly rare. But as wind farms grow older and the underlying components age, regular and proactive maintenance become far more important.

MORE: Why accident, safety data is hard to come by for wind industry

Yet landowners have been raising concerns to PGE for the last decade about maintenance issues at Biglow Canyon and their impact on energy production at the facility. And an investigation by The Oregonian/OregonLive has found that the seemingly isolated blade incident is part of a wider set of maintenance problems and equipment failures that are now undercutting electricity generation at Biglow Canyon, shortchanging ratepayers and landowners, and putting those who cultivate crops under the turbines – and potentially their farmland itself – at risk.

Among the findings:

- PGE has failed to report public safety incidents at Biglow Canyon, in potential violation of its operating agreement with the state. The utility hasn't disclosed incidents where hatches, metal disks and blade bolts have fallen off turbines from a height of about 265 feet. PGE has questioned whether such incidents meet the reporting threshold, but regulators insist even small objects may be a hazard to anyone near a turbine because they can reach almost 90 mph when falling.

- PGE knowingly operated at least four turbines at Biglow Canyon with broken blade bolts, in one case for nearly a year, maintenance records show. Those bolts clamp blades to the rotor and bear the stress of wind and motion. Research indicates that broken bolts, while not uncommon, can become a serious problem leading to catastrophic blade failures like the one in February.

- Oil leaks from Biglow Canyon's wind turbines and transformers are environmental and fire hazards. The turbines have been plagued by leaks of oil and lubricants that coat towers and blades and spit on to their gravel pads and surrounding fields. Transformers have ruptured regularly, causing two fires and spilling about 3,000 gallons of mineral oil into surrounding soil that prompted expensive cleanups.

- The number of problems PGE has disclosed to regulators is out of line with other wind farms. Since 2010, PGE has reported more than a dozen oil spills and other incidents at Biglow Canyon with the potential to affect public safety — about three times more than any other wind farm regulated by the state. But state officials only recently began pressing PGE to explain those troubles.

- Biglow Canyon has generated far less power than PGE originally projected. The availability of its Vestas wind turbines to produce energy has abruptly declined in recent years, and the project's rate of energy production is less than neighboring wind farms of comparable age.

- Ratepayers may end up footing the bill for assets that are no longer useful. The project's 76 turbines manufactured by Vestas are halfway through their projected life but PGE is already considering replacing them. If that happens by the end of 2023, ratepayers would be stuck covering $156 million in remaining costs.

Kathryn McCullough, a Sherman County landowner, examines a bolt off the blade that was thrown from a turbine at PGE's Biglow Canyon wind farm on Feb. 1. "Someone could have been killed or badly injured," she said.

The Biglow Canyon turbine that launched its blade is one of about 72,000 machines nationwide, including some 2,300 turbines in Oregon, which has more production capacity than all but nine other states. Yet there is no effective national, state or county reporting requirement or database tracking safety or operational incidents at wind farms, and only 13 of the largest of Oregon's 48 wind farms are regulated by the state, numbers that include multiple phases of some projects.

PGE launched an investigation into this winter's blade throw and is filing written updates to regulators. But it has asked the Oregon Department of Energy to keep those confidential until the end of the year because of the possibility of litigation.

Seven months into that review, PGE told The Oregonian/OregonLive that preliminary results suggest the connection between the turbine blade and its hub was "not well clamped," a problem likely caused by "bolts becoming loose and experiencing fatigue damage over time."

PGE said it took the blade failure "very seriously as a safety incident" and is working to fully understand the cause, rectify it and make any other necessary adjustments to improve operations.

But PGE defended its overarching maintenance efforts. It said that state regulators have not issued any violations for failing to report safety incidents; only two of the incidents it did report were actually related to public health and safety; leaking oil posed only a low environmental or fire risk; and lost service time is likely the result of grid constraints beyond its control. The issues at Biglow Canyon, it said, are consistent with those experienced by other utilities with similarly aged equipment.

"PGE entered into a long-term maintenance contract with the maker of the turbines, a wind sector leader, Vestas," PGE spokesperson Melissa Havel said in response to written questions. "This was a prudent and industry standard action on the part of PGE. We challenge your categorization of the volume of troubles. Since coming online, Biglow Canyon wind farm has generated more than 13,000,000 MWh of clean electricity, which translates to powering 120,000 homes per year."

Even so, PGE said it has now taken a more active role monitoring the turbines at Biglow Canyon, analyzing incoming data for anomalies or patterns that may indicate performance or safety issues. PGE officials said the utility could also end up suing Vestas, which maintains all the turbines there and manufactured the one that launched the blade. PGE said it has streamlined Vestas' scope of work so the company can focus more on preventative maintenance.

Vestas said it completed its own investigation into the blade failure but could not share results because they contain proprietary information. Vestas, which has its North American headquarters in Portland, said there was no evidence to suggest that inadequate maintenance has shortened the lifespan of turbines at Biglow Canyon, and that the project continues to operate at or above industry standards.

Most of the turbines at Biglow Canyon have now returned to service.

“We wouldn’t run it if it wasn’t safe,” said Jesus Carrera, PGE’s manager of wind operations.

Maintenance issues at Biglow Canyon matter broadly because PGE – Oregon’s largest electricity provider, serving some 900,000 homes and businesses in Oregon – plans to transition to 100% carbon-free energy by 2045. And its customers will be paying the bill.

To eliminate all its greenhouse emissions, PGE would need to supersize its fleet of renewable energy resources and manage them for longevity, maximizing production for decades to come. Yet the economics of wind power are heavily dependent on federal subsidies, and some experts suggest those subsidies are structured in a way that incentivizes operators to skimp on maintenance for older equipment that is no longer eligible.

PGE’s operations and maintenance expenses at Biglow Canyon have declined precipitously, federal records show. In 2021, PGE spent 40% less than it did eight years earlier, and it told economic regulators that spending would be even lower this year.

PGE said it has consistently invested in Biglow Canyon’s operations while also striving to maintain competitive rates and balancing customer cost implications. “We expect to remain consistent with our investments this year until we determine the best future course of investment,” Havel added.

The blade thrown from a turbine at PGE's Biglow Canyon wind farm on Feb 1. An outbuilding next to the McCullough's residence is shown in the background.

Meanwhile, Biglow Canyon landowners who believe in the promise of green energy have been left frustrated, not only by a perceived lack of transparency from PGE, but also because they feel financially shortchanged by excessive turbine downtime, as payments to them are based on energy production.

Don Godier, a retired air force colonel who lives in Florida, said it's always been a team effort to scratch a modest living out of the farm his great grandparents established. The family was fired up by the prospect of "harvesting the wind" by placing turbines on their land. But the resulting payments from PGE, which he said he uses to support his mother's long-term care, haven't met expectations.

"We were a little naïve and trusting," he said, "but those days are over."

Landowners recently hired a Portland lawyer to investigate potential remedies.

The McCulloughs, whose house and farm are surrounded by turbines, have been particularly vocal. They've regularly complained to PGE and recently provided documentation about maintenance concerns to the office of U.S. Sen. Ron Wyden, Oregon's senior senator and a member of the Senate Energy and Natural Resources Committee.

"If you think about it, any of those things could come down at any time," said Kathryn McCullough, a retired 747 airline captain. "If we maintained our equipment like that, we wouldn't be farming for long."

Kathryn McCullough, a Sherman County landowner, examines the blade that was thrown from a turbine at PGE's Biglow Canyon wind farm on Feb. 1. Her husband, Kevin McCullough, farms wheat under about half the wind farm's 217 turbines, including the one that threw the blade. Thirteen of the wind farm's turbines are on their land.

'What's not to like?'

When a wind prospecting outfit first approached Sherman County residents in 2001 about leasing out portions of their cropland to a wind farm operator, the McCulloughs were immediately intrigued.

The nation's wind energy boom was just getting off the ground. California was adopting rules requiring utilities to invest in green power, soon to be followed by Oregon and Washington. And the Columbia River Gorge, with solid winds and existing transmission lines established to carry hydropower around the west, would soon become a hotbed of wind farm development and eventually become one of the top ten wind energy producers in the nation.

The big-talking wind prospector was spinning tales of the Learjets landowners would soon own, the McCulloughs remember.

It seemed like a no-brainer.

And while state and county regulations limit public access to the land under wind farms, there are virtually no off-limit areas for farming. That meant farmers could continue to cultivate nearly right up to the base of the turbines, harvesting crops from the ground and a regular stream of lease payments from overhead machines.

The McCulloughs and their neighbors soon became big backers, expressing support for the Biglow Canyon project at various forums as other groups raised concerns about its visual and noise impacts, bird mortality and operations of a nearby airport. Kevin McCullough even appeared in a **promotional video for the project**.

It took several years, but the project gained momentum, first steered by Orion Energy, then PGE.

The first 76 Vestas turbines under construction at Biglow Canyon wind farm in 2007. Kevin McCullough, right, looked on enthusiastically at the time. He farms under about half of the wind farm's 217 turbines today and earns lease payments based on electricity production from the 13 turbines on land he and his wife own there. (File photos by Ross William Hamilton)

By 2007, the first 76 turbines manufactured by Vestas were up and spinning on the McCulloughs' and neighboring farms. They were followed by 141 Siemens machines by 2010, in what was then the largest wind farm on the Columbia Plateau. PGE said costs from the $1 billion project would raise ratepayers' monthly bills by a total of 4.5% while producing the equivalent amount of energy used by 125,000 homes in a year.

PGE's Biglow Canyon wind farm was a reality. The electricity – and the dollars – began to flow.

"We were ecstatic," Kathryn McCullough said of the 13 turbines on their land. "What's not to like? When these things are turning, we're making $100,000 a year. How do you shake a stick at that?"

'Just pure carelessness'

Long before the blade flew into the night at Biglow Canyon, landowners say they had concerns about substances spewing from PGE's turbines.

Problems began more than a decade ago. The McCulloughs said they expressed concern to PGE that the Vestas turbines, then only three years old, were leaking oil and lubricants from the nacelles, the box atop the turbine tower that houses its gearbox and other major components.

It’s a condition that persists today. Many of the once-pristine white Vestas turbines are visibly soiled by oil, blackening the towers, the blades, the gravel pads and spitting into the fields below. The McCulloughs snapped photos of the problem as recently as early August showing their truck spattered in oil after just 30 minutes parked near a turbine, and the ground darkened with oil spots.

The leaks likely fall below the threshold for reporting oil spills to the Department of Environmental Quality, which requires disclosure only for discharges to the ground over 42 gallons in any 24-hour period. And officials at the Department of Energy said the problem had not been brought to their attention by a member of the public, during annual inspections or by PGE, so they haven’t looked into it.

Kevin McCullough parked his truck near one of Biglow Canyon’s Vestas wind turbines for about 30 minutes during wheat harvest in early August. When he returned, he said it was spattered in oil leaking from the top of the turbine. At right, oil spots on the ground nearby the same turbine. Landowners worry that regular leaks of oil and lubricants from Vestas turbines, which PGE says is a fixable problem if it chooses to make the investment, could be contaminating their cropland. (Courtesy Kathryn McCullough)

Godier, the property owner paying for his mother’s care, said he’s driven cross country twice in the past few years and made it a point to check conditions at other wind farms.

“I didn’t see a single one with the amount of oil and grease we have on ours,” he said, while speculating that it could be seeping into the water table. “It’s on the ground. Someone needs to hold these folks liable for what we’re going to find in 50 years.”

Residents who own land under PGE's Biglow Canyon wind farm worry that regular leaks of oil and lubricants from turbines pose fire and environmental hazards.

Brett Gray, who farms under PGE's turbines, said the Vestas turbines seem the worst, but the Siemens machines at Biglow Canyon leak, too. He also farms under turbines at another wind farm to the south, Klondike, and regularly passes by others.

"It's not the norm for the projects I've been around," he said of the oil, adding that PGE told landowners there's "no way to fix" the Vestas turbines. "But that's hard to believe."

PGE's spokesperson said Vestas has identified a solution and could install retrofit kits to equipment that is prone to leaking. But PGE hasn't decided whether to make those fixes, saying it must first choose between enhanced maintenance of existing turbines or replacing them.

A metal frame and pieces of fiberglass fell from the spinner cone of this Vestas turbine into a field below at Biglow Canyon wind farm in April 2021. PGE didn't report the incident to regulators until this summer. Wind technicians later lowered the turbine's nose cone and spinner frame onto the turbine pad, where the pieces remained for a year. The nose cone blew into a nearby gully, and remained there earlier this month.

Mark Haller, a wind industry consultant who spent 40 years managing and developing wind farms across the globe until retiring last year, said that if the turbines continue to leak oil, "it's because someone isn't spending the money to fix them."

"Those machines should not be puking oil all over the place, other than just pure carelessness," he said.

The same model of Vestas turbines used at Biglow Canyon, officially known as the V82 1.65mw, are in operation at the Echo wind farm about 50 miles to the east. They were commissioned in 2009, two years after those at Biglow Canyon, and are partially owned by a group of farmers.

Kent Madison, one of the farmers there, said he's seen an occasional leak from the gears in several turbines, but they've been promptly fixed, cleaned and look nothing like the machines at Biglow.

"Ours have run like a fine watch," he said. "We have not had any issues over the years."

Brad Jenkins, PGE's vice president of utility operations, this summer led a reporter on a guided tour of Biglow Canyon that didn't include any of the soiled turbines. Jenkins downplayed the potential environmental issues, saying the oil leaks were confined to the machines, and said PGE would never run a turbine with a fire risk.

Biglow Canyon has never experienced a turbine fire. But they do happen in the industry, with a 2,000-acre blaze in Gilliam County four years ago linked to a turbine operated by a different company, according to compliance reports submitted to the state.

"Just because an asset is dirty doesn't mean it's not running well," Jenkins said. "We're more concerned with what's on the inside."

Portland General Electric provided a look inside the spotless nacelle of a Vestas turbines (left) at Biglow Canyon wind farm during a tour in late June. Kathryn McCullough sent the pictures at right to U.S. Sen. Ron Wyden, which she said shows the oil-coated nacelle of a Vestas turbine this spring at Biglow Canyon. (Photos courtesy PGE, left, and Courtesy Kathryn McCullough, right)

The guided tour included showing off the inside of a spotless turbine. But Kathryn McCullough recently emailed Oregon's senior senator photos she said she obtained from a contractor showing the inside of a turbine at Biglow Canyon this spring.

The machinery appeared filthy, heavily coated in oil, the photos show.

PGE declined to comment, saying the photos had no metadata attached so it couldn't confirm where or when they were taken.

Oil has also leaked from Biglow Canyon's on-site transformers, which sit at the base of each turbine and are used to regulate electrical current.

Ten transformers have failed at Biglow since 2010, three times more than reported by any other facility regulated by the state, according to Department of Energy records. Nine transformers under both Vestas and Siemens turbines and one in a substation spilled some 3,400 gallons of mineral oil — 90% of it to the ground around the turbines, prompting excavation and soil replacement.

"Ten transformer failures?" said Haller, the industry consultant. "That's bad."

PGE's Jenkins said oil used in transformers is essentially vegetable oil, and poses minimal environmental or fire hazard. But the mineral oil used in transformers is flammable, and transformers have caught fire at Biglow Canyon in 2011 and 2013.

After nine transformer ruptures and related oil spills since 2010, state regulators this year pressed PGE for answers about the problems. But after hearing from a utility official in January, they took no further action.

PGE has experienced 10 transformer failures at Biglow Canyon that have collectively leaked 3,000 gallons of mineral oil to the ground surrounding turbines and caused two fires. Pictured above, pad-mount transformers sit in cabinets below each turbine at Biglow Canyon.

Lenna Cope, a project specialist at PGE, told regulators during a public meeting transformer failures are an industry-wide problem and PGE was replacing them with transformers with different specifications when they failed. She said the demand on turbine transformers is unique because it rises and falls with rapid changes in the wind, and resulting temperature changes can degrade transformer oil and insulators, leading to the buildup of combustible gasses. The gas accumulation can over pressurize a tank, cause a rupture or, if there's an electrical arc, flash off and cause an explosion.

"PGE has a program to sample each transformer for dissolved gasses, but there are no industry standards to compare the results for decision making and accurately predict pending failures," Cope said. "PGE does our best to make prudent choices."

Screen shots of a ruptured transformer and the required cleanup of a transformer oil spill from a presentation that PGE made to state regulators in January about transformer problems at the wind farm.

After watching PGE's presentation online at The Oregonian/OregonLive's request, Tony Sleva, the president of Prescient Transmission Systems, said it appeared to be tailored for an audience with limited knowledge of electrical equipment, and a panel of electrical engineers would have been more skeptical. Sleva, whose expertise includes forensic analysis of aging and failed electrical equipment, told the newsroom that testing gas in oil is an effective method to predict remaining transformer life, the methodology is well understood, and the science simple.

“PGE needs to obtain the service of a forensics lab,” he said in a statement, adding that without intervention the number of failures would likely climb.

Two weeks after Cope’s comments to regulators, another transformer failed at Biglow Canyon, leaking 166 gallons of mineral oil to the surrounding ground.

‘They’d hurt you’

Pieces of turbine equipment are now falling into landowners’ fields with some regularity.

PGE has not reported those incidents to the state promptly, or in some cases at all. That’s a potential violation of state administrative rules governing wind farms, as well as the conditions in Biglow Canyon’s operating permit with the state.

Take the metal frame and pieces of fiberglass that fell off the damaged nose cone of a Vestas turbine in April 2021. PGE didn’t report it until June of this year, and only after a reporter asked why it hadn’t been disclosed to regulators.

State rules require wind farm owners to operate the facility in a way that prevents structural failures of the tower or blades that could endanger public safety, and PGE’s operating permit requires a report within 72 hours of any incident with the potential to impact public safety.

Pieces from a damaged Vestas V82 wind turbine at Biglow Canyon. PGE told regulators a metal frame and pieces of fiberglass fell off the turbine in April 2021. Wind technicians later lowered the turbine’s nose cone and spinner frame to the ground, where they were left for a year.

After PGE questioned whether such an incident was reportable, the Department of Energy made it clear to PGE that it was, noting that even a small item falling from about 265 feet could reach 130 feet per second, the equivalent of almost 90 miles per hour.

At "those speeds, even a small object may present a hazard and raises questions with both the adequacy of and compliance with the requirements of PGE's Operational Safety-Monitoring Program," Wally Adams, an analyst at the department, wrote to the utility.

Using that standard, it appears PGE should have been reporting a lot more public safety incidents, based on what landowners say happens.

Kevin McCullough said that over the years, he has found 10 to 12 hatch doors, most of them beaten up and coated in oil, that have broken off the top of the Vestas turbines and fallen into the fields he farms. Each measures 25 inches by 29 inches and weighs about 10 pounds. He picks them up so his combine doesn't, and either sits them against the base of the turbines or delivers them to PGE's office.

Gray, one of the neighboring farmers, confirmed the same. "The Vestas turbines, they lose doors all the time and you'll see them laying in the field. They'd hurt you. My neighbors won't park by them."

Likewise, the McCulloughs' son, Colton, said he's found several metal disks with a Siemens label attached, of about the same size and weight as the Vestas hatches, that have fallen off the Siemens turbines.

Landowners say they find hatch doors (left) from the Vestas turbines at Biglow Canyon and metal disks (center) from the Siemens turbines that break off and fall into their fields from a height of about 265 feet. State regulators say even small objects falling from that height can reach speeds of nearly 90 mph and could endanger anyone below. (Courtesy Kathryn McCullough)

PGE has also discovered at least one instance of broken blade bolts falling from the turbines. Last year, the company discovered broken bolts on four of its Siemens turbines, maintenance reports obtained by The Oregonian/OregonLive show. In three cases, those were identified during annual inspections or during repairs, while broken blade bolts were found under one of the turbines in the fourth instance.

It's not clear how many blade bolts were broken or missing on each turbine. But PGE did not report the bolts, or the fallen hatches or disks, to the state.

Havel said PGE has reported "consistent with our understanding" of state rules and "in alignment with other wind operators' reporting patterns" but will "continue to evaluate our practice to ensure we are meeting" the state's expectations. PGE told regulators in July that it would hold meetings with staff and contractors to review the types of events that trigger reporting requirements.

The Department of Energy told the newsroom it would require reporting of a broken blade bolt found below a turbine but wouldn't say if the obligation would apply to other items, without having more details from the wind farm operator or a member of the public.

"We will investigate if it's reported to us," said Todd Cornett, assistant director of the Department of Energy siting division.

What is clear is that PGE kept its four Siemens turbines with broken blade bolts running for months while awaiting spare parts. In one case, according to the maintenance reports, PGE left a turbine in service with broken bolts for nearly a year.

Jenkins, the PGE manager, defended the decision. He said both Siemens and Vestas specify how many bolts attaching a blade to the rotor hub can be loose or broken and have the turbine remain operational. He declined to say what those specifications are, saying PGE is under a non-disclosure agreement.

Flags marking debris in a wheat field after a Vestas V82 wind turbine at Biglow Canyon threw one of its eight-ton blades the length of a football field on Feb. 1.

Andrew Luther, a spokesperson for Siemens Gamesa, said in a statement that it provides focused recommendations for Siemens turbines with broken blade bolts, but that “as every wind farm has a unique combination of location, wind conditions, equipment, age, and maintenance schedules, we do not have the necessary information to comment on this situation.” He also declined to comment on falling equipment or oil leaks because the company is not responsible for maintaining turbines at Biglow Canyon.

Vestas said most oil leaks are contained within the turbine structure, don’t affect performance and have a low risk of migrating to surrounding areas.

In the “rare instance” that objects fall to the ground, it is the responsibility of the wind turbine owner to make any required report to regulators, it said.

“Vestas investigates and repairs issues provided the failure falls within Vestas’s agreed upon scope with the wind turbine owner.”

The company said that when broken blade bolts are found, engineers make the determination on a case-by-case basis.

“Under certain circumstances and with the necessary engineering assessment, Vestas’ guidelines may allow for temporary wind turbine operation with additional guidelines,” it said in response to written questions. Those might include extra inspections and replacing additional bolts around the broken bolt during repair.

PGE said it had not identified broken bolts on Vestas turbine No. 71 or any of the other Vestas machines before this winter’s blade throw. But it found broken bolts and other problems on other machines afterward — including a cracked blade bearing, a steel ring that connects the blade to the rotor hub and controls the blade angle to the wind. PGE had to replace both the bearing and the attached blade as a result.

“A cracked blade bearing is a biggee,” said Haller, the retired industry consultant.

PGE told regulators its inspections this year included hiring a contractor to check the torque on “a representative sample” of more than 10,000 blade bolts at Biglow Canyon, and it submitted 50 of the failed blade bolts from the thrown blade for specialized metal testing.

Project maintenance reports obtained by The Oregonian/OregonLive show broken blade bolts were found on four more Siemens turbines and two more Vestas machines. The reports show those machines were taken offline by PGE.

Jenkins told the newsroom that if a certain percentage of blade bolts on a given turbine were not within specifications, it planned to replace all bolts on that blade. Havel later said that it replaced all the bolts on four Vestas turbines but, after testing the metal, concluded full bolt replacement was unnecessary on additional turbines.

The failure of blade bolts due to stress and metal fatigue is cited as a frequent cause of turbine failure, according to a recent study published in the academic journal Engineering Failure Analysis, which presented a methodology to predict the remaining life of in-service wind turbine bolts.

Metal blade bolts do have some ability to stretch and deform without breaking. But over time, they begin to lose that elasticity, and corrosion or cracking can cause them to snap under severe loads.

Workers replacing the blades on a Vestas V82 wind turbine at Portland General Electric's Biglow Canyon wind farm in late June. The turbine threw one of its blades into a wheat field on Feb. 1. PGE blamed "a loss of clamping force."

When a fatigue failure occurs, the paper said, it's difficult to pinpoint the origin after the fact, which complicates the decision on whether to replace bolts on every turbine or just the one with failed bolts. "It is of paramount importance to know whether the fatigue-damaged bolts are in general throughout the whole farm/park, only of one turbine or only those of one connection."

One of the paper's authors, Daniel Garcia Vallejo, a professor of mechanical engineering at the University of Seville in Spain, said in an email that catastrophic failures typically result from a cascading set of events.

"Usually, the first bolt will break due to fatigue, and after a number of other bolt breakages the rest will break due to overload," he wrote.

Asked if it was considered safe, under any circumstance, to run a turbine with broken blade bolts, he replied, "I don't think so. When one bolt breakage is detected it should be analyzed and repaired."

'It could produce so much more'

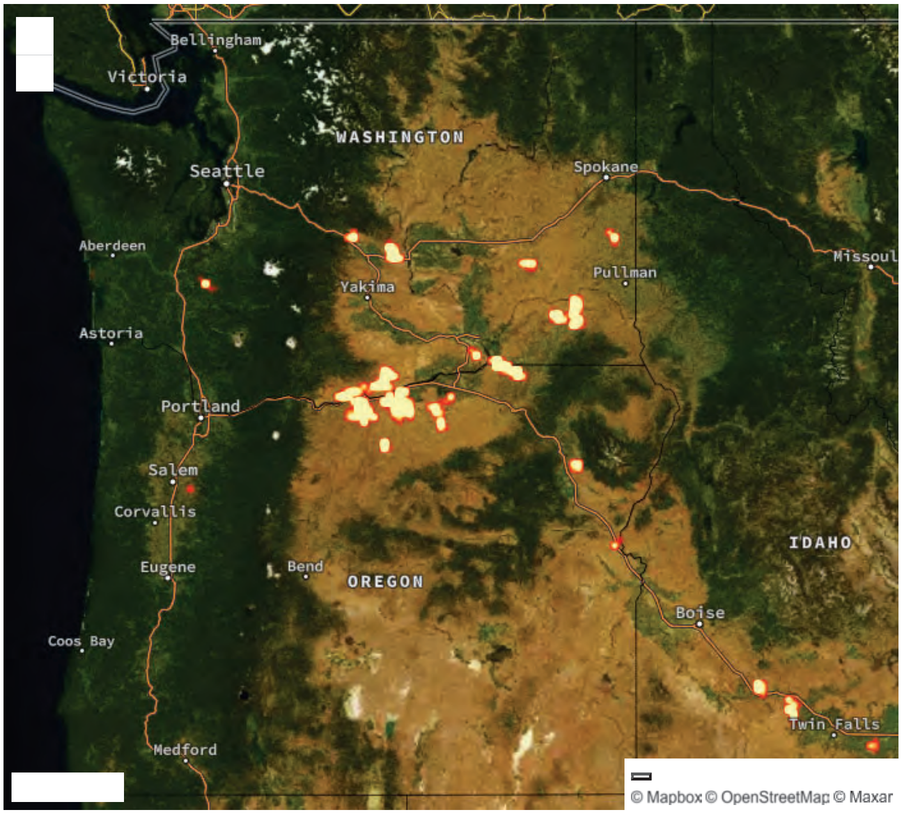
Amid the problems, landowners say Biglow Canyon's turbines often resemble giant lawn ornaments, sometimes sitting idle for months at a time.

And that is what they find most exasperating, and something they contend should also concern utility ratepayers and regulators, who aren't getting the carbon-free energy production they are paying for and expect.

"It's a good rent, but I'm complaining because it could produce so much more electricity," said John Scharf, who has 26 of the project's turbines on his land.

Where the turbines are

The U.S. Geological Survey maintains a database of more than 72,000 onshore and offshore wind turbine locations in the United States. **Zoom to Biglow Canyon wind farm**



Oregon wind farms

Oregon has about 2,300 turbines across 48 wind farms, mostly concentrated near the Columbia River Gorge.

Search:

Farm	County	Turbines	Model	Operator	Distributor
Benson Creek Wind Farm	Baker	5	GE 2.0	DE Shaw Renewable Investment / Oregon Wind Farms	Idaho Power
Biglow Canyon Phase 1	Sherman	76	Vestas V82 1.65	PGE / Orion Energy	PGE
Biglow Canyon Phase 2	Sherman	65	Siemens SWT 2.3	PGE	PGE
Biglow Canyon Phase 3	Sherman	76	Siemens SWT 2.3	PGE	PGE
Combine Hills	Umatilla	41	Mitsubishi MWT 1000	Eurus	PacifiCorp / Energy Trust of Oregon
Combine Hills II	Umatilla	63	Mitsubishi MWT 1000	Eurus	PacifiCorp
Condon (Phase I)	Gilliam	41	Mitsubishi MWT 600	ALLETE / AES / SeaWest	BPA
Condon (Phase II)	Gilliam	42	Mitsubishi MWT 600	ALLETE / AES / SeaWest	BPA

DE Shaw

Sources: U.S. Geological Survey, Renewable Northwest
Map: Mark Friesen/staff

Biglow Canyon has been a disappointment from the start.

In 2008, when PGE first asked the Oregon Public Utility Commission to approve a rate increase to cover the cost of the first phase of Biglow Canyon, it told commissioners it expected the Vestas turbines would generate, on average, about 37% of their rated capacity of 125.4 megawatts.

That number is known as a turbine's "capacity factor," which accounts for the fact that wind doesn't blow all the time. It's an important contributor to wind farm economics, as it tells you not only how much power they'll generate but how many federal subsidy dollars are likely to flow to the project.

The project's capacity factor has never hit 37%. In their first five years of operation, compliance reports filed with the state show the Vestas turbines had an average capacity factor of 31%, meaning the project widely missed its initial projections.

A Vestas V82 turbine, missing a hatch door, at PGE's Biglow Canyon wind farm this summer. Farmers say the hatches fall into their fields from a height of 265 feet. (Courtesy Kathryn McCullough)

"Phase one was clearly not very good," said Bob Jenks, a ratepayer advocate for the Citizens' Utility Board of Oregon. "They'd probably argue that it was new technology and they were learning how to operate it. But they asked us to pay for output, not a learning experience."

By the time the last turbines were finished in 2010, PGE said publicly that the entire project's capacity factor was expected to be about 33%. Instead, it's averaged 27.6% – again, well below projections.

PGE said its estimates were based on assumptions and history of wind at the location, and that as the industry matures and it collects more weather pattern data, it can now more accurately assess wind farms capacity factors.

Nearby facilities are performing better.

The Patu wind farm, a six-turbine operation owned by a neighboring landowner that opened in 2010 and sits directly adjacent to some of Biglow's turbines, has had an average capacity factor of 36%. Klondike III, a large, neighboring wind farm of comparable age, has maintained consistently higher capacity factors than Biglow, averaging 29.2%, which over the years adds up to a lot of extra generated electricity.

Gray said he has four Biglow Canyon turbines on his land to the north and west of the Patu wind farm. He said he seldom sees any of the neighboring turbines down.

"He's not on any exceptional ridge," Gray said of the Patu operator. "When they built Biglow, they built on the best wind resource available."

PGE said different environmental factors and plant features affect the capacity factors of each, and that "these wind farms are not directly comparable."

State regulators separately require wind farm operators under their jurisdiction to report how often equipment is available to generate power, regardless of whether the wind is blowing.

On-shore wind turbines tend to be very reliable, typically available more than 95% of the time, according to James Manwell, a professor in the Department of Mechanical and Industrial Engineering at the University of Massachusetts who studies wind energy.

Farmers cultivate wheat right up to the base of wind turbines at Portland General Electric's Biglow Canyon wind farm (left). An aerial shot (right) of a Vestas turbine on Feb. 22, after it threw a blade 100 yards into a field below.

Among wind farms under state jurisdiction that have been operational for at least 10 years, all have hit that mark, on average, including Biglow Canyon. But the Vestas machines at Biglow have failed to achieve that target in half the years they've operated, plummeting to 88.5% in 2020 and 86.5% in 2021.

This year's performance could be worse, as many of the Vestas turbines were down three or four months after the blade separation.

Doug Medler, a Portland resident who sold his land to the McCulloughs three years ago but retained the wind rights, said his payment for the second quarter of this year was about $5,250, compared to about $17,850 in the same quarter last year, a 71% reduction.

"It's a significant hit," he said. "It's a big source of income, but not one that affects my ability to put food on the table or pay the utility bill."

During the past five years, PGE has offered landowners various reasons for the turbine downtime: low wind; plant curtailments by the Bonneville Power Administration when the region's hydroelectric dams are producing too much energy; and more recently, aging equipment and a lack of parts due to disruptions in the global supply chain. PGE has also said it's sometimes advantageous to ratepayers to run its other wind plants that are still within the 10-year eligibility window for federal production tax credits, and shut down Biglow Canyon, which is no longer eligible for the subsidies.

PGE told the newsroom substation and transmission outages initiated by the Bonneville Power Administration likely affected Biglow Canyon in 2020 and 2021. "There were no equipment failures or breakdowns that significantly impacted availability or capacity," PGE previously told regulators about those years.

Yet in emails to Kathryn McCullough about frustrations over downtime, a PGE official last year acknowledged the role of failing equipment.

Nick Loos, the director of dam safety and renewable energy, blamed increased downtime on wear and tear, "end of life issues" that were "rearing its ugly head" and the need for PGE to stay ahead of the "failure curve."

"The past maintenance strategy of replace as main components fail has worked in the past," he told her, "but with the increase in failures we need to mature our maintenance strategy. Work we are doing in the background is focused on preventative maintenance."

'Need to hold the utilities responsible'

The path forward for Biglow Canyon is uncertain.

Company officials have pledged to improve safety and performance, and Wyden, the senator, has vowed to keep watch.

"PGE is updating our office regularly with the inspection status, as well as committing to provide our office with a longer-term inspection and maintenance plan," Hank Stern, a spokesperson, said in an email. "Sen. Wyden will keep watchdogging this issue to ensure PGE follows through on its commitment to him and the community."

Financially, PGE appears to have two routes to address issues.

Jenkins, the utility's vice president of operations, insists that PGE is managing the project – and the Vestas turbines – for longevity, focusing on preventive maintenance to keep small problems from turning into big ones. "I don't know that with the age of these assets, the case can be made that they're not performing," he said.

Brad Jenkins, PGE's vice president of utility operations, watches as workers install new blades in late June on the Vestas turbine that threw a blade on Feb 1.

But keeping the turbines performing at a high level may require significant investments, and PGE's filings with regulators don't reflect that reality.

In fact, PGE's operations and maintenance expenses at Biglow Canyon have steadily declined, despite the aging equipment and acknowledged need for major repairs. PGE spent $13 million last year, down 40% from 2013, according to figures filed with the Federal Energy Regulatory Commission. That's the lowest total since 2010.

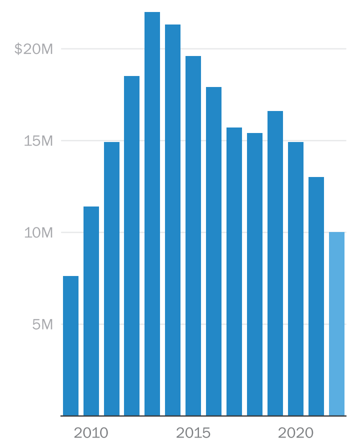
And in documents submitted to Oregon regulators, the company said it would spend even less this year: $10 million.

If that seems strange, perhaps it shouldn't.

A 2020 study by researchers at Lawrence Berkeley National Lab found that wind plant performance in the United States declines suddenly after 10 years – far more abruptly than output dropped in Europe or Asia. One theory the authors offered: As plants aged out of the 10-year window for federal production subsidies, they don't warrant more intensive operations and maintenance activities to maximize production.

Biglow Canyon operation and maintenance expenses

PGE's operations and maintenance expenses at Biglow Canyon have declined 40% since 2013, despite aging equipment and inflation in the price of wind turbine components. The company projects spending even less this year - $10 million – as it considers whether to "repower" the project's Vestas towers with new components or invest more heavily to keep the existing equipment running.



**2022 figure is an estimate*

Get the data

A wind technician enters a Vestas turbine at PGE's Biglow Canyon wind farm. The project's 76 Vestas turbines are now 15 years old, about halfway through their depreciable life. PGE is already considering replacing them.

A related hypothesis cited by the research: regular maintenance that was deferred to maximize production while the wind farms were still eligible for the tax credits eventually comes home to roost in the form of increased breakdowns.

PGE's alternative to spending more on maintenance would be to repower the Vestas turbines, replacing most of their components, increasing their efficiency and output. It's not uncommon. And PGE is considering it.

If that happens, ratepayers could end up eating the remaining value tied to the existing machines. The Public Utility Commission said that was $178 million at the end of last year and would decline to about $156 million by the end of 2023.

The likelihood of repowering may have just gotten higher, as the Inflation Reduction Act passed by Congress this month renewed the federal production tax credit subsidy for another 10 years for wind and solar farms that begin construction prior to Jan. 1, 2025, including those repowering turbines.

Any decision to repower turbines at Biglow Canyon would be subject to a so-called "prudency review" by the Oregon Public Utility Commission to determine whether the investment is in the public interest. That decision would include all the costs involved, including the remaining costs of the turbines being repowered, the cost of the new equipment, and the available tax credits.

Jenks, the ratepayer advocate, said the review would also include an analysis of whether the current equipment has been properly maintained, and if not, what went wrong.

"If we're going to make a transition to clean energy," he said, "we need to hold the utilities responsible for managing these projects properly."

The landowners would like that same level of accountability.

"When we entered into the agreement, the objective of the company and the landowners leasing the land was to have the project work, and make money," said Cheryl Woods, a Biglow Canyon property owner and the accountant for the wind prospecting company that originally arranged the lease.

"But it doesn't seem to be exactly going that way. It just hasn't been managed well."


A Vestas wind turbine at PGE's Biglow Canyon wind farm.