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

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EXHIBIT LIST

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

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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	
4	Washington CCA Allowances	
5	Mid-C Specified, Zero Carbon Sales	
6	Production Tax Credit Rate	
7	Gas Option Placeholder	
8	Reliability Contingency Event	
9	Thermal Parameters	
10	Beaver Cycling	
11	Carty Outage Rate	
12	2023 AUT - Trans. RDC	
13	2023 AUT - BP-24 Wheeling Rates	
14	2024 Wheeling Expenses	
15	Biglow Capacity Factor	
16	Balancing Impacts*	
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

MONET vs. EIM Downward Flexibility Reserves (MW) 2020-2022

[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.

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[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. <u>Specified Source Non-Emitting Sales</u>

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

[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

[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

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[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.