**Portland General Electric Company**
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
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April 1, 2021

***Via Electronic Filing***

Public Utility Commission of Oregon
P.O. Box 1088
Salem, OR 97308-1088

**RE: UE_XXX - In the Matter of Portland General Electric Company's 2022 Annual Power Cost Update Tariff (Schedule 125)**

Dear Filing Center:

Attached for filing in the above referenced matter please find the following:

- **Direct Testimony of**:
  - Sophiya Vhora, Darrington Outama, Greg Batzler (PGE / 100) and Exhibits 101-105
  - Robert Macfarlane, Teresa Tang (PGE / 200) and Exhibits 201-204
- **Motion for Approval of Protective Order (with proposed Protective Order)**

Non-confidential work papers will be submitted to puc.workpapers@puc.oregon.gov.

PGE will submit confidential work papers and confidential Exhibits 102 through 105 after entry of a Protective Order. PGE is requesting expedited consideration of its Motion for Approval of the Protective Order.

PGE's initial forecast of 2022 net variable power costs is $511.8 million. PGE's preliminary estimate of base rate impacts is an increase effective January 1, 2022 of about 2.4%.

Sincerely,

/s/ *Jaki Ferchland*

Jaki Ferchland
Manager, Revenue Requirement

JF/np
Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

# UE XXX

# Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

*Sophiya Vhora*
*Darrington Outama*
*Greg Batzler*

April 1, 2021

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# I. Introduction

**Q. Please state your names and positions with Portland General Electric Company (PGE).**

A. My name is Sophiya Vhora. My position at PGE is Manager, Financial Analysis & Power Cost Forecasting.

My name is Darrington Outama. My position at PGE is General Manager, Power Operations.

My name is Greg Batzler. My position at PGE is Regulatory Consultant, Regulatory Affairs.

Our qualifications are included at the end of this testimony.

**Q. What is the purpose of your testimony?**

A. The purpose of our testimony is to provide the initial forecast of PGE's 2022 Net Variable Power Costs (NVPC). We discuss several of the updates to the parameters (e.g., ancillary service assumptions) from PGE's NVPC forecast for 2021, as well as modeling changes. We compare our initial 2022 forecast with PGE's final 2021 NVPC forecast and explain why the per-unit expected NVPC have increased by approximately $1.92 per MWh.

**Q. What is PGE's initial net variable power cost forecast?**

A. Our initial 2022 NVPC forecast is $511.8 million, based on contracts and forward curves as of February 26, 2021. This initial 2022 NVPC forecast represents an increase of approximately $53.9 million relative to our final 2021 NVPC forecast.

**Q. What are the primary factors that explain the increase in NVPC forecast for 2022 versus the NVPC forecast for 2021 in Docket No. UE 377?**

A. The primary factors contributing to the increase in NVPC include: 1) an increase in costs associated with market purchases due to a 78 MWa load increase in 2022 and 2) an increase in costs associated with contract and market energy purchases and sales. The increase is partially offset by reduced costs associated with increased expected generation from our gas, coal, hydro, and wind resources, compared to the final 2021 NVPC forecast.

**Q. Are there Minimum Filing Requirements (MFRs) associated with PGE's NVPC filings?**

A. Yes. Public Utility Commission of Oregon (OPUC or Commission) Order No. 08-505 adopted a list of MFRs for PGE to follow in AUT filings and General Rate Case (GRC) filings. The MFRs define the documents that PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 101 contains the list of required documents as approved by Commission Order No. 08-505. The MFRs required for our initial filing are included as part of our electronic work papers, with the remainder of the MFRs to be submitted within 15 days of this filing (i.e., April 15, 2021). As with PGE's NVPC filings in the 2021 NVPC proceeding, the MFR documents are designated as either "confidential" or "non-confidential."

**Q. Is PGE subject to any new requirements as part of this proceeding?**

A. Yes. Pursuant to Commission Order No. 20-321, PGE is now required to submit a report as part of its annual power cost filing that details the performance of the Wheatridge facility. PGE provides additional details regarding this report in Section III, part F.10.

**Q. What schedule do you propose for NVPC updates in this docket?**

A. We propose the following schedule for our power cost update filings:

- April – Update parameters and forced outage rates; power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; update to California Carbon Allowance (CCA) forward price curve; and the Wheatridge facility performance report;

- July – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; CCA forward price curve; planned thermal and hydro maintenance outages; and loads;
- October – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; CCA forward price curve; planned hydro maintenance outages; and loads; and
- November – Two update filings: 1) update gas and electric forward curves; CCA forward price curve; final updates to power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; long-term customer opt-outs; and 2) final update of gas and electric forward curves; final update to Qualifying Facilities commercial operation dates; and final update to the price of the power contract with Grant County.

**Q. How is the remainder of your testimony organized?**

A. After this introduction, we have four sections:

- Section II: MONET Model
- Section III: MONET Updates and Modeling Changes
- Section IV: 2022 Load Forecast
- Section V: Comparison with 2021 NVPC Forecast; and
- Section VI: Qualifications.

## II. MONET Model

**Q. How did PGE forecast its NVPC for 2022?**

A. As in prior dockets, we used our power cost forecasting model, called "MONET" (the Multi-area Optimization Network Energy Transaction model).

**Q. Please briefly describe MONET.**

A. We built this model in the mid-1990s and have since incorporated several refinements. Using data inputs, such as an hourly load forecast and forward electric and gas curves, the model minimizes power costs by economically dispatching plants and making market purchases and sales. To do this, the model employs the following data inputs:

- Retail load forecast, on an hourly basis;
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, operating constraints, emissions control chemicals, and any variable operating and maintenance costs (although not part of NVPC for ratemaking purposes, except as discussed below);
- Hydroelectric plants, with output reflecting current non-power operating constraints (such as fish issues) and peak, annual, seasonal, and hourly maximum usage capabilities;
- Wind power plants, with peak capacities, annual capacity factors, and monthly and hourly shaping factors;
- Transmission (wheeling) costs;
- Physical and financial electric contract purchases and sales; and

- Forward market curves for gas and electric power purchases and sales.

Using these data inputs, MONET simulates the dispatch of PGE resources to meet customer loads based on the principle of economic dispatch; generally, any plant is dispatched when it is available, and its dispatch cost is below the market electric price. Thermal plants can also be operating in one of various stages – maximum availability, ramping up to its maximum availability, starting up, shutting down, or off-line. Given thermal output, expected hydro and wind generation, and contract purchases and sales, MONET fills any resulting gap between total resource output and PGE's retail load with hypothetical market purchases (or sales) priced at the forward market price curve. In Section III below, we discuss our most recent enhancements to PGE's MONET power cost model.

**Q. How does PGE define NVPC?**

A. NVPC include wholesale (physical and financial) power purchases and sales (purchased power and sales for resale), fuel costs, and other costs that generally change as power output changes. PGE records its net variable power costs to Federal Energy Regulatory Commission (FERC) accounts 447, 501, 547, 555, and 565. As in the 2021 NVPC proceeding, we include certain variable chemical costs, lubricating oil costs, and we include forecasted federal production tax credits (PTCs). We exclude some variable power costs, such as certain variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. Based on prior Commission decisions, certain fixed costs, such as excise taxes and transportation charges, are included in MONET. For the purposes of FERC accounting, these items are included with fuel costs in a balance sheet account for inventory (FERC 151); this inventory is then expensed to NVPC as fuel is consumed. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, natural gas, fuel and associated financial instruments.

**Q. Do the MFRs provide more detailed information regarding the inputs to MONET?**

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop our initial forecast of 2022 NVPC.

## III. MONET Updates and Modeling Changes

**Q. Does PGE present both parameter updates and modeling enhancements in this initial filing?**

A. Yes. We include not only the parameter revisions allowed under PGE's AUT (Tariff Schedule 125), but also model enhancements and updates.

**Q. What updates are allowed under PGE's Schedule 125, AUT Tariff?**

A. Schedule 125 states that the following updates are allowed in AUT filings:

- Forced Outage Rates based on a four-year rolling average;
- Projected planned plant outages;
- Wind energy forecast based on a five-year rolling average;
- Costs associated with wind integration;[1]
- Forward market prices for both gas and electricity;
- Projected loads;
- Contracts for the purchase or sale of power and fuel;
- Emission control chemical costs;
- Changes in hedges, options, and other financial instruments used to serve retail load;
- Transportation contracts and other fixed transportation costs;
- Reciprocating engine lubrication oil costs; and
- Projections of State and Federal Tax Credits.

[1] PGE is proposing in this proceeding to revise Schedule 125 to allow for the recovery of costs associated with variable energy resources integration rather than only wind. Please see PGE Exhibit 200 for more information.

**Q. Does PGE discuss other items that could have an impact on the 2022 NVPC forecast and customer prices but do not represent updates or MONET modeling enhancements?**

A. Yes. In Section III.A below, we discuss how recent changes in the Western Energy Coordination Council (WECC), the Pacific Northwest Power Pool (NWPP), and PGE's resource capacity stacks impact PGE's actual power operations and costs and potential avenues to mitigate that impact.

**Q. What updates and model enhancements does PGE include in this AUT filing?**

A. We include all the updates listed above. Additionally, we include, and we discuss in this testimony the following updates and modeling enhancements:

- Section III.B: Lydia Hourly Price Shaping Model Update (Lydia 2.0)
- Section III.C: Western Energy Imbalance (EIM) Market Dispatch Benefits
- Section III.D: Gas Storage Optimization Enhancements
- Section III.E: Variable Energy Resources Integration
- Section III.F: Other Items:
    1. Wheatridge Solar and Battery Storage (Wheatridge 2.0)
    2. Pacific Northwest Coordination Agreement Study
    3. Qualifying Facilities (QF) Energy Derate and Tracker
    4. Pelton-Round Butte maintenance outage in 2022 and ownership percentage change
    5. BPA Rate Case Impact on the 2022 NVPC forecast
    6. Transmission Resale Revenue Forecast
    7. Beaver Plant Upgrade
    8. Faraday Hydro Coefficient Update

9. Blue Marmot QF Projects Aggregation
10. Wheatridge Facility Performance Report

**Q. What is the net effect on PGE's initial 2022 NVPC forecast of the updates and modeling enhancements included in the initial MONET step-log?**

A. The net effect of the updates and modeling enhancements reflected in the initial MONET step-log is a $12.4 million increase in PGE's initial 2022 NVPC forecast from the base NVPC forecast.

**Q. Are there items that have a cost impact in the 2022 initial NVPC forecast and are discussed in this testimony but are not reflected on the initial step-log?**

A. Yes, we are discussing the following items and their associated cost impact although they are not included on the initial NVPC step-log: 1) Pelton-Round Butte Outage and Ownership Percentage Change, 2) Transmission Resale Revenue Forecast, and 3) Beaver Plant Upgrade.

**Q. Why do you include both updates and modeling enhancements in this AUT filing?**

A. PGE is expecting to submit a general rate case filing after the enclosed AUT filing. To ensure the NVPC forecast is not truncated and to give parties more time to evaluate the proposed modeling enhancements, we are including both updates and MONET enhancements in this filing. Should PGE decide a general rate case filing is not needed to ensure just and reasonable customer prices in 2022, we would remove the modeling enhancements proposed in this filing.

**Q. Has PGE discussed any of the above proposed updates and changes with the Public Utility Commission of Oregon (OPUC) Staff, the Oregon Citizen's Utility Board (CUB), or the Alliance of Western Energy Consumers (AWEC) prior to this April 1 initial filing?**

A. Yes. Prior to this initial filing, PGE held three separate workshops to discuss a number of the NVPC updates and enhancements proposed in this filing. Specifically, we held the following workshops:

- December 16, 2020 workshop discussing expected 2022 NVPC updates and enhancements with OPUC Staff. Exhibit 102 provides the December 16, 2020 workshop presentation;
- January 25, 2021 workshop discussing with OPUC Staff, AWEC, and CUB: 1) gas supply of the Port Westward / Beaver complex, 2) transmission resale revenue methodology, and 3) changes implemented to the EIM sub-hourly dispatch benefits method. Exhibits 103 and 104 provide the January 25, 2021 workshop presentations; and
- March 5, 2021 workshop discussing updates and enhancements to be included with the initial April 1 AUT filing with OPUC Staff, AWEC, and CUB. Exhibit 104 provides the March 5, 2021 workshop presentation.

**Q. What load forecast does PGE use in this initial filing?**

A. We use the 2022 retail load forecast described in Section IV. Our forecast is approximately 19,437 thousand MWh of cost-of-service energy, or approximately 2219 MWa, an increase of 78 MWa from the final 2021 test year forecast (Docket No. UE 377).

## A. Capacity Planning

**Q. Why is PGE discussing capacity planning within the 2022 NVPC forecast testimony?**

A. We are discussing this issue to address the rapid changes we have seen and continue to see to the energy resource capacity landscape within the WECC region, which directly impacts PGE's ability to meet customer peak loads with market purchases. More specifically, over the last two decades, a significant amount of firm and dispatchable generation has been retired or decommissioned within the WECC region. These resources are not replaced in kind. Instead, additional non-dispatchable renewable generation such as variable wind and solar resources have been built due to economics, customer demand, and increasing Renewable Portfolio Standard targets. This fundamental change in regional energy supply has accelerated in recent years and is adding significant complexity to the forecasting, planning, procurement, and dispatch decisions around PGE's capacity and energy needs as well as increased uncertainty around costs. PGE has altered its operational practices to maintain reliability and contain costs for customers as a result of these continued changes. While PGE has no specific proposal in this initial AUT filing, we want to ensure parties are aware of these complexities as we forecast and anticipate our operational needs for each year.

**Q. How has the resource capacity stack changed over the last two decades in the Pacific Northwest and California?**

A. As provided in Figures 1 and 2 below, between 2001 and 2010, in the Northwest Power Pool (NWPP) and the California Independent System Operator (CAISO) regions, the resource capacity stack was largely composed of dispatchable thermal plants fueled by coal, natural gas, and hydro. In the latter part of 2000s and the 2010s, increasing amounts of renewable solar and wind energy were added to the resource stack while inefficient yet dispatchable gas plants and coal plants were retired; a trend that is expected to continue in future years. For example, in 2020, PGE retired its 556 MW Boardman firm and dispatchable coal generating plant and added 300 MW of nameplate wind generation with the completion of the wind portion of the Wheatridge Renewable Energy Facility.

**Figure 1: NWPP Generation Capacity Stack**

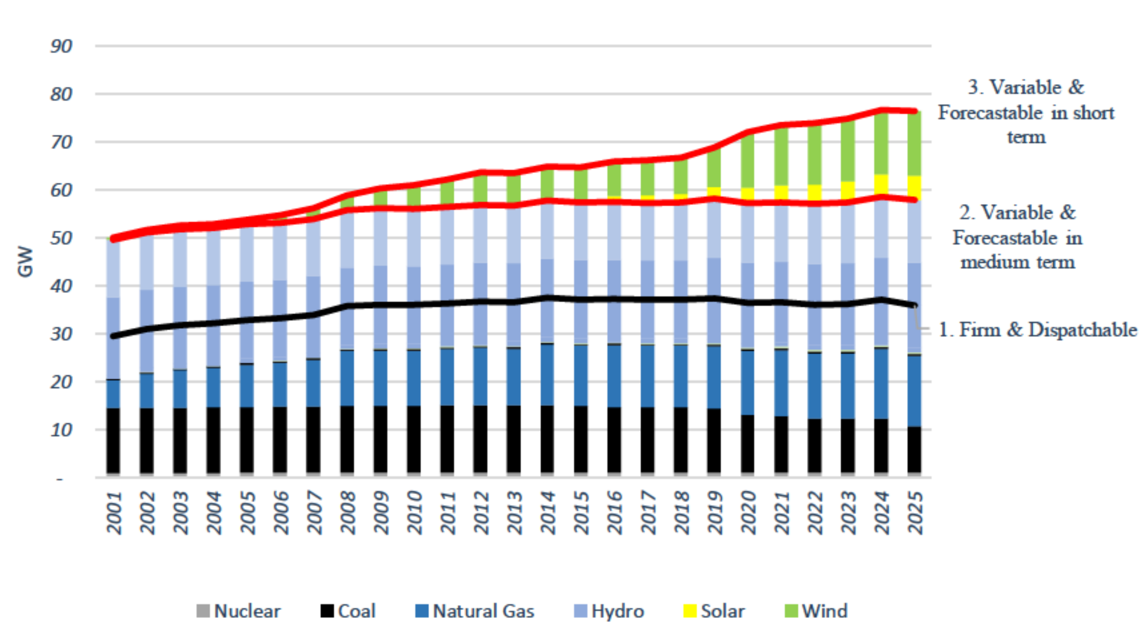
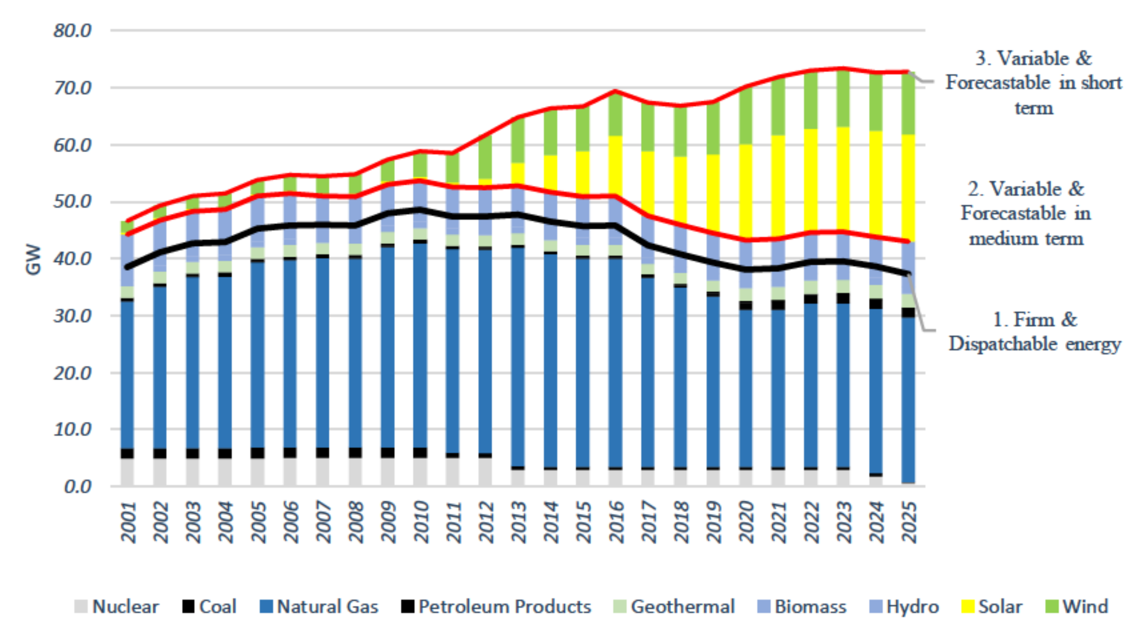



**Figure 2: CAISO Generation Capacity Stack**




**Q. How did PGE's resource stack change in the last 20 years?**

A. In the early 2000s, PGE's resource portfolio was comprised predominantly of coal, natural gas, hydro resources, and market purchases. PGE first began adding new renewable resources after the adoption of the Oregon RPS in 2007. We continued to add renewables in order to meet our commitments to decarbonize our portfolio and to support Oregon's goals to reduce economywide greenhouse gas (GHG) emissions. PGE completed the Biglow Canyon wind project in 2010, the Tucannon River wind generating facility in 2015, and the wind portion of Wheatridge in 2020. Currently, PGE's resource portfolio includes more than one gigawatt of name plate capacity of wind generating resources.

**Q. What do you expect in the medium-term regarding the regional energy resource capacity stack?**

A. PGE expects that the retirement of coal and additional renewables resources will continue, such that, by the end of 2025, approximately 40 percent of the regional energy capacity stack will be wind and solar.

**Q. What is the primary cause for the change in the WECC energy resources landscape?**

A. As noted above, the origin for the shift in the types of energy resources in the region is primarily related to the adoption of ambitious state renewable energy standard plans and other decarbonization actions in WECC states. For example, in 2007, the Oregon legislature passed Senate Bill (SB) 838 establishing Oregon's first renewable portfolio standard (RPS), and in 2016, through SB 1547, the RPS was significantly accelerated. The current Oregon RPS requires large utilities to gradually meet increasing RPS targets. The target is current set at 20 percent but increases to 50 percent in 2040 and beyond. Additionally, as articulated in Executive Order No. 20-04 issued in 2020, Oregon Governor Kate Brown calls for substantial reductions in economywide GHG emissions (i.e., reduce GHG emissions at least 45 percent below 1990 levels by 2035 and at least 80 percent below 1990 levels by 2050).

Similarly, California established an RPS requirement in 2002[2] and Washington state in 2006.[3] The intent of the RPS requirements was to increase the amount of clean energy generation over time. Furthermore, amidst broad consumer- and policy-driven change toward renewable resources, manufacturers driven efficiency gains and lowered manufacturing costs made clean technologies cost competitive when compared to conventional fossil-fuel generators for energy production. Additionally, the expiring or phasing out of federal Production Tax Credit made early build out of renewable resources economically desirable.

**Q. What are the most prominent impacts from the changing mix of energy resources in the WECC region?**

A. First, the reduction in regional firm and dispatchable resources is causing a regional capacity shortage. This manifests in the form of extreme price volatility and increases the number of scarcity price events during weather driven load excursions or other market events. This phenomenon has created a gap between how we dispatch our plants in actual operations versus the economic dispatch in MONET. Second, even during times of relatively normal load conditions, the shift from firm and dispatchable resources to variable energy resources (VERs) has resulted in increased price volatility as observed in the day-ahead energy market due to wind and solar generation uncertainty. We discuss this increased market price volatility vis-a-vis wind output and our proposed approach to more accurately capture its' cost impact in the MONET forecast in Section III.B.

**Q. You mention above that regional capacity shortages can result in scarcity pricing.**

[2] The California RPS program was accelerated in 2015 with SB 350 which mandated a 50 percent RPS by 2030.
[3] The Washington state RPS program established in 2006 requires investor owned utilities to be 100 percent greenhouse gas neutral by 2030 and 100 percent renewable or zero-emitting by 2045.

**When does this occur within a particular energy market?**

A. Energy markets start to exhibit scarcity pricing when the forward market heat rate exceeds the heat rate of the highest priced energy resource available in that market. The market heat rate is a calculation of the market energy price divided by natural gas prices for a specific term and location. In addition, as the market transitions from the forward to day-ahead market, volatility around that average forward price has to account for new information such as weather, forced plant outages, and other event risks driving it higher with a bias toward extremely high prices.

**Q. Why has scarcity pricing and PGE's exposure to it increased in recent years?**

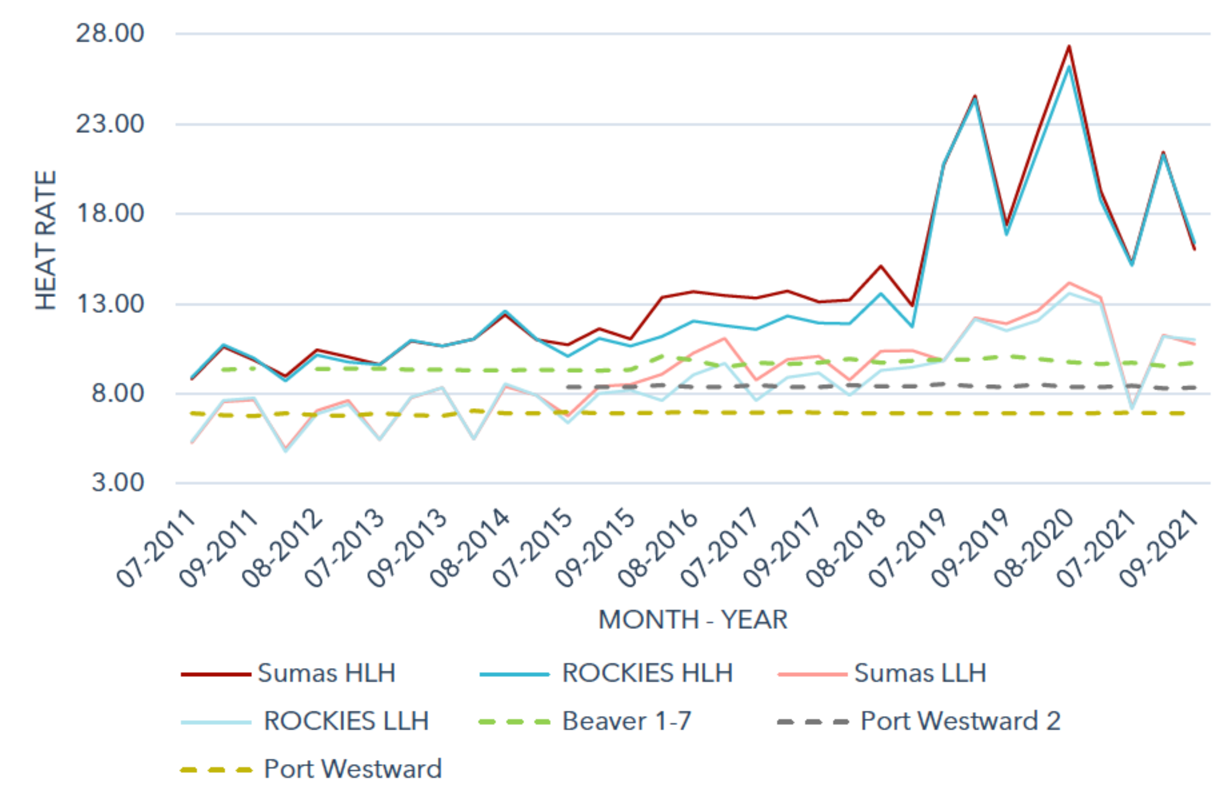
A. Historically, the forward market heat rate has settled at or below Beaver's dispatch cost, one of the oldest plants in the region. Therefore, in the past, the market predicted that the oldest plant in the region would only be needed in the highest usage months, typically August. It would be understood that any load and price excursion would bring Beaver online to meet that additional energy need. As provided in Figure 3 below, in recent years, the forward market heat rate has disconnected from the regional energy supply stack during summer months. That is, the forward market heat rate increased dramatically in recent years, reaching almost 28 mmBtu/MWh in Q3 of 2020. PGE's marginal heat rate units are Beaver, at approximately 9.4 mmBtu/MWh, and Port Westward 2 (PW2) at approximately 8.9 mmBtu/MWh, capacity resources generally used for peaking and wind-following purposes in actual power operations. The market is therefore showing that all of the thermal plants in the region need to be "on", and additional market purchases, at prices no longer based on a marginal cost of a unit, are needed to meet demand in the summer. Furthermore, the market is also indicating that any additional load demand beyond the average load would have no natural price "ceiling" that would be set by a unit that is not yet economic to be turned on (as what Beaver would have been in the past).

**Q. Please explain how the forward market heat rate impacts the NVPC forecast in MONET.**

A. As described in Section II, MONET is an economic dispatch model. Hence, if the plant is economical to dispatch, MONET will run the plant (subject to its constraints) to either displace market purchases or increase market sales to meet net load and reduce the total NVPC forecast. Given the significant increase in the market heat rate and the fact that the load forecast only reflects average peak,[4] MONET finds it economical to dispatch capacity resources such as Beaver and PW2 for energy. If that generation is in excess of customers' average load it is in turn "sold" to the market. The margin for these economic sales offset cost to serve load in the summer months.

[4] 1-in-2 peak load forecast means that there is a 50 percent probability that forecast peak with be less than actual peak load, and a 50 percent probability that the forecast will be greater than actual peal load.

**Figure 3: HISTORICAL PLANT HEAT RATE vs. FORWARD MARKET HEAT RATE**




**Q. How does MONET's plant dispatch compare to PGE's actual power operations?**

A. PGE Power Operations (Power Operations) is tasked with reliably meeting customers' load first and foremost. Once that is done in compliance with all applicable rules and regulation, Power Operations will dispatch the portfolio to minimize costs. In order to meet the first obligation, PGE tends to hold the dispatch of marginal heat rate capacity plants such as Beaver and PW2 for reliability purposes heading into a cold or heat event to ensure we can meet any potential spikes in load. This practice both meets reliability standards and minimizes the risk of run-away costs by caping customers' exposure at the cost of Beaver and PW2. This practice is contrary to MONET's pure economic dispatch: Power Operations would not capture the full dispatch margin that was modeled in the AUT. If Power Operations were to sell that power forward, it would no longer have its cost-based resources to meet load excursions, exposing power costs to a potentially run-away market. Because MONET does not factor reliability into its forecasting modeling logic, it will economically dispatch those units for energy. Power Operations would only be able to capture the economic margins of those peaking plants on normal weather days. The timing and frequency of these normal weather days are not known or knowable at the time of the AUT or anytime subsequently until in the week or day-ahead planning. At which time, weather forecast, plant operations, and prices are more predictable allowing Power Operations to commit to these forward sales. Consequently, to ensure reliability during super-peak events, PGE's actual power operations is not in alignment with the MONET modeling.

**Q. What is the most significant risk for PGE due to the gap between MONET modeling and actual power operations?**

A. Since Power Operations plans and operates differently than MONET's forecast, risk to customer reliability is unchanged from historical norms. Therefore, the most significant risk is that the AUT forecast materially underestimates the cost to serve customers during summer months. Oftentimes, weather driven scarcity pricing during summer months drives PGE to pursue market purchases to meet higher customer load when prices exceed retail revenue rates established through MONET modeling in the AUT or GRC processes.

**Q. What are potential remedies to mitigate the capacity shortage issue?**

A. The MONET model is a deterministic, energy-only model that cannot address, from a modeling perspective, capacity shortages that cause scarcity pricing. Thus, customer prices do not include any capacity shortage risk that PGE is experiencing in actual operations. In the long term, PGE is evaluating potential changes to the MONET modeling to introduce a capacity planning capability to the model. However, we are not proposing any MONET changes at this time.

**Q. Are there other approaches to mitigating the capacity shortage issue in the short-term?**

A. Yes, there could be two potential approaches. One possible strategy is for PGE to enter into a structured capacity agreement to help mitigate the exposure to weather driven load excursions and meet load without being exposed to a run-away market.

**Q. Has PGE included a new capacity contract within its initial 2022 NVPC forecast?**

A. No. However, PGE is exploring options and could execute a capacity contract that would be effective in 2021 and with extended terms to include 2022 and 2023 to address this issue in the short term.

**Q. What is a second possible strategy?**

A. A second possible strategy would be to artificially withhold a portion of the Beaver or PW2 capacity from the MONET dispatch utilizing the planned outage logic. For example, PGE would add a planned maintenance outage for three gas turbines at Beaver and three PW2 engines, withholding approximately 200 MW capacity for the period between July 15 and September 15. This approach would withhold this generator capacity from the deterministic economic dispatch in the MONET logic thereby simulating the actions and the frequency that PGE would take operationally to ensure reliability.

**Q. Does PGE propose to update the Beaver and PW2 planned outage logic to simulate PGE's actual operations?**

A. Not at this time. Should PGE propose in a subsequent update or proceeding, we will provide more information to parties.

## B. Lydia 2.0 Methodology

**Q. Why is PGE updating the Lydia methodology?**

A. As described in detail below in this section, PGE is updating the Lydia methodology to incorporate the empirically observed intra-month wind generation volatility and its relative impact on intramonth Mid-C market prices.

**Q. What is the Lydia model?**

A. Lydia is an hourly price shaping model, which is deterministic and mean-reverting. Its historical purpose has been to create hourly price distributions from forward (monthly) on- and off-peak prices to support the NVPC forecast in MONET.

**Q. Please describe the base Lydia 1.0 methodology?**

A. Lydia 1.0 broadly refers to the 'base' or pre-existing methodology that has been used for intra-month (hourly) Mid-C price shaping and wind generation shaping; both of which are based on an average-view of any given month. The Lydia 1.0 hourly Mid-C prices follow a set of normalized price distributions, or scalars, for each weekly sub-period (weekdays, Saturdays, and Sundays). This means that all the weekdays, Saturdays, and Sundays within the month have the same respective shape. Thus, the resulting hourly energy curves represent an average week for the given month.

**Q. When was Lydia 1.0 methodology developed?**

A. The Lydia 1.0 methodology was developed in the early 2000s when the power supply portfolio in the WECC, in general, and the Pacific NW, in particular, was significantly different from today's energy resources landscape, as described in Section III.A, above. While the power supply stack has changed significantly, the Lydia methodology has not been updated to reflect the effects of increasing amounts of VERs generation (predominantly wind resources) and reduced amounts of regional capacity on the energy prices on an intramonth basis.

**Q. How does VER generation impact energy market prices?**

A. As stated above in Section III.A (Capacity Planning), VER generation has resulted in increased regional energy price volatility in the day-ahead market due to wind and solar generation variability. Prior to the addition of wind and other VERs to the NWPP resource capacity stack, regional price volatility was most often due to low hydro forecasting and would occur in the mid-term time frame, three to nine months ahead. Increasing amounts of wind generation in the Pacific Northwest, concentrated in Oregon and Washington, has made wind generation the current 'price setter' in the NWPP region. Figure 1, on page 11, provides the change in the NWPP resource stack and illustrates the significant increase in wind generation in the last two decades. Because wind generation impacts energy prices in the day-ahead market and there are no available generation signals on the term forward basis, the market exposure to wind forecasting is considerable, not just at a gross daily production level, but on an hour-to-hour level.

**Q. How does wind generation correlate with energy market prices?**

A. Wind generation exhibits a negative correlation to Mid-C energy market prices. Because wind generation is the current 'price setter' at the Mid-C power trading hub, when there is significant production of wind in the Columbia Gorge, the energy price at Mid-C will depress while, equivalently, when there is low wind production, the energy price at Mid-C will increase. Additionally, wind generation has an asymmetrical impact on energy market prices, being more pronounced during periods of high-power prices, or price scarcity periods.

**Q. How is wind generation shaped in MONET?**

A. Currently, PGE uses a rolling five years of historical average wind generation to calculate an annual capacity factor, monthly shape factor, and an hourly shape factor:

- The annual capacity factor is representative of the average wind generation over the most recent five-year historical period.
- The monthly shape factor, which is relative to the annual capacity factor, reflects the monthly average generation over the same five-year historical period on a monthly basis.
- The hourly shape factor, which is relative to the monthly shape factor, represents the average generation by hour-month for the same historical time period.

The resulting output is a 12 X 24 matrix where all days within the given month have the same 24-hour shape profile and hence, no intramonth generation variability.

**Q. What is the relationship between MONET's wind generation shaping and Mid-C prices within the Lydia 1.0 methodology?**

A. There is no relationship between the two variables. This is a fundamental issue which we are attempting to address with our proposal. The Lydia 1.0 methodology treats the intramonth wind generation shaping and the hourly energy price shaping as two independent processes such that the market behavior described above remains uncaptured in the NVPC forecast. Furthermore, due to the one average monthly profile for both wind generation and hourly price shaping, the Lydia 1.0 methodology fails to capture the intramonth volatility in wind generation and its effects on energy prices.

**Q. How is PGE proposing to address the correlation between wind generation and market prices?**

A. PGE is proposing an updated Lydia 2.0 methodology that incorporates the effects of wind generation volatility on energy prices and provides for an NVPC forecasting methodology that is in greater alignment with current market fundamentals.

**Q. Please describe the Lydia 2.0 methodology.**

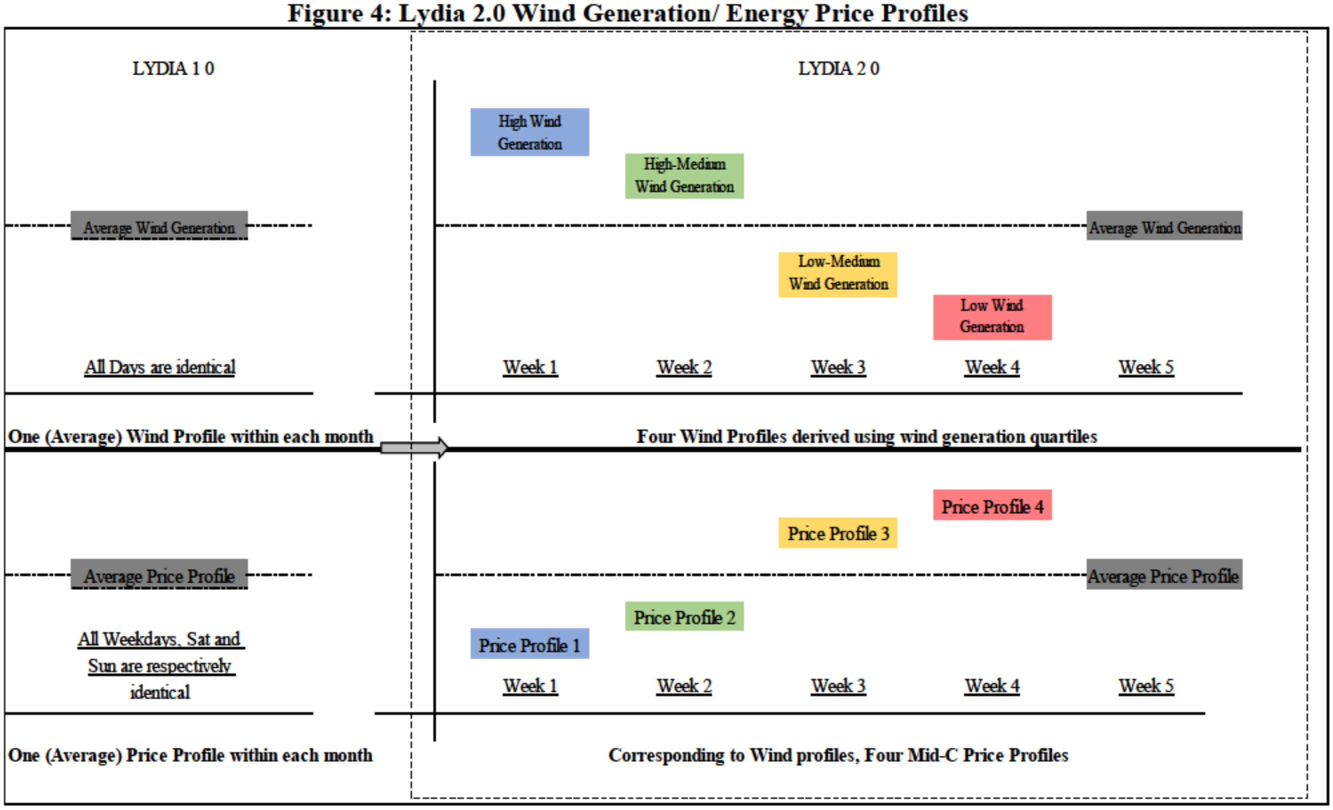
A. Lydia 2.0 is built as an enhancement to the Lydia 1.0 methodology. This enhancement allows for intramonth redistribution of wind generation and Mid-C prices while keeping the methodology deterministic and mean reverting. The output from this update will have <u>four</u> wind generation profiles, compared to the <u>one</u> average intramonth profile produced by the Lydia 1.0 methodology. Corresponding to each of these wind generation profiles, there is a Mid-C price profile. These profiles are applied to each week within any given month:

1. Wind High Generation → Energy Price (Profile 1)
2. Wind High-Medium Generation → Energy Price (Profile 2)
3. Wind Low-Medium Generation → Energy Price (Profile 3)
4. Wind Low Generation → Energy Price (Profile 4)

**Q. How do the four wind and energy price profiles compare with the Lydia 1.0 methodology monthly shape for price and the wind generation shape used in MONET?**

A. As provided in Figure 4 below, the four profiles average back to the base case Lydia 1.0 methodology. In each month, the four wind generation profiles average back to the one wind generation profile (per Lydia 1.0). Furthermore, the average of the on-peak and off-peak hourly prices for the four profiles equal the forward Mid-C on-peak and off-peak monthly price curve. As a result, on a monthly average basis, the values for Mid-C prices and wind generation remain consistent with the Lydia 1.0 methodology and overall, the methodology remains deterministic and mean-reverting.

**Figure 4: Lydia 2.0 Wind Generation/ Energy Price Profiles**




**Q. What is the Lydia 2.0 methodology impact on the 2022 NVPC forecast?**

A. The update to the Lydia methodology results in a 2022 NVPC forecast increase of approximately $5.6 million.

## C. Western Energy Imbalance Market (EIM)

**Q. Please summarize PGE's 2022 EIM net benefit forecast.**

A. PGE's 2022 EIM net benefit forecast is summarized in Table 1. Forecast EIM sub-hourly dispatch savings (including savings from CAISO flex ramp awards) and GHG benefits are reduced by a grid management charge forecast.

**Table 1**
**2022 Net Benefits Forecast Western EIM Participation**

| | **NVPC Net Benefits** | |
|---|---|---|
| 1 | Sub-Hourly Dispatch Savings and Flex Award | $5.5million |
| 2 | GHG Benefit | $2.7 million |
| 3 | CAISO Grid Management Charges[5] | ($1.1 million) |
| | **Total** | **$7.1 million** |

<u>**EIM Sub-Hourly Dispatch and Forecast for 2022**</u>

**Q. How does the EIM method to forecast sub-hourly dispatch benefits in the 2022 test year compare to the method used in the 2021 test year forecast in Docket No. UE 377?**

A. PGE's forecast for sub-hourly dispatch cost savings follows for the most part the same methodology used in the 2021 NVPC forecast (UE 377), with certain refinements to address concerns that parties raised in UE 377 and to better reflect actual EIM operations.

**Q. Commission Order No. 20-390 in UE 377 provided that PGE hold a workshop to discuss certain EIM sub-hourly benefits modeling issues prior to the 2022 NVPC initial filing. Did the workshop take place?**

A. Yes, parties held a workshop on January 25, 2021. In the workshop PGE addressed EIM transaction limits methodology changes that parties proposed in UE 377. PGE also responded to parties' questions regarding how EIM trades in the forecast are representative of trades that occur in actual operation and the interaction between PGE's participation in the EIM and PGE's reserve requirements.

**Q. Please describe PGE's forecast for sub-hourly dispatch benefit methodology used to determine EIM cost savings in the 2021 NVPC forecast in UE 377.**

[5] CAISO grid management charges are designed to recover Independent System Operator (ISO) costs associated with staff and portions of the ISO system that are used to support EIM functionality.

A. PGE's forecast for EIM sub-hourly dispatch cost savings in the 2021 AUT was closely linked with the MONET hourly modeling of the 2021 NVPC forecast. As described earlier in Section II, MONET simulates the dispatch of PGE resources to meet customer loads based on the principle of economic dispatch and under expected conditions. In each hour, MONET will fill any gap between total resource output and PGE's retail load with market purchases (or sales) priced at the forward market curve.

For purposes of calculating a 2021 forecast for sub-hourly dispatch cost savings from the EIM, PGE treated MONET's purchases and sales as transactions made prior to the EIM operating hour. These transactions were then compared to an EIM price curve[6] to determine if MONET sales should be purchased back under EIM pricing, or if MONET purchases should be sold at EIM prices.

**Q. Has PGE implemented changes to the EIM methodology for sub-hourly dispatch savings in the 2022 NVPC forecast?**

A. Yes. PGE enhances the EIM methodology for sub-hourly dispatch savings in four ways:

1. PGE calculates thermal and hydro monthly transaction limits based on a weighted average (instead of the simple average used in the 2021 NVPC forecast).
2. PGE expands its EIM logic to increase or decrease commitment and/or dispatch from the marginal thermal resource if EIM prices are even more favorable than Mid-C prices.
3. PGE includes the net benefit of CAISO flex ramp awards in its benefit forecast. The net benefit forecast is based on the three-year simple average of historical settlement data.

[6] The EIM price curve was calculated as the average of PGE's 2018 and 2019 fifteen-minute market prices, adjusted for price outliers.

**Q. Please describe in more detail the weighted average method applied to transaction limits.**

A. For the 2021 AUT in UE 377 PGE identified hydro and thermal transaction limits based on actual CAISO instructions from 2019 data and used the fifteen-minute market and five-minute market changes from submitted resource to establish monthly limits on market activity allowed during each MONET trading hour. For the 2022 forecast, we made the following updates:

1. Three years of historical fifteen-minute market and five-minute market changes is being used to determine the 2022 EIM monthly transaction limits (instead of one year).[7]
2. All intervals are used in the calculation except for those interval values that exceed 1.5 times the interquartile range of the dataset.[8]
3. The interval values in the dataset are the result of combining all hydro movement as one resource and combining all thermal movement as one resource. This summation of the movement across plants aligns with the valuation methodology in MONET where the entire EIM trade is valued at either the marginal thermal resource for the hour or the mid-c price for the hour (i.e., opportunity cost of hydro): Using an "INC" (i.e., incremental) limit as an example, Table 2 compares the limit formulas between 2021 and 2022.

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[7] PGE does revise the historical quantity associated with the Pelton Round Butte facility to account for the full Round Butte outage planned for 2022.

[8] The interquartile range (IQR) is the difference between the third quartile and the first quartile in a data set, resulting in the middle 50 percent. The 1.5 times the IQR method is commonly used to identify outliers in the data.

**Table 2: EIM Monthly Transaction Limits**

| | |
|---|---|
| 2021 EIM Monthly Transaction Limits | $Monthly\ INC\_DEC\ Limit = \dfrac{Total\ INC\_DEC\ Vol(MWh)}{\frac{\#\ of\ Days}{24hrs}}$ |
| 2022 EIM Monthly Transaction Limits | $Monthly\ INC\_DEC\ Limit = \dfrac{Total\ NET\ INC\_DEC\ Vol(MWh)}{\#\ of\ INC\_DEC\ Intervals} * 12$ |

**Q. Please describe the update to the method to forecast a 2022 EIM price curve.**

A. To forecast the 2022 EIM prices PGE continues to use historical EIM prices but also applies a shaping to align the hourly EIM prices with the hourly Mid-C prices that result from the Lydia 2.0 methodology.

Specifically, to derive an EIM price curve for the 2022 test year, PGE is using the average of 2018, 2019, and 2020 fifteen-minute market prices (translated in hourly EIM prices) and Mid-C hourly prices to develop hourly 'EIM price factors'.[9] These EIM price factors, then get used to derive an EIM price forecast relative to the Mid-C hourly prices:

$$(\text{EIM Factor}) = (\text{EIM Price})_{\text{historical}} \div (\text{Mid-C Price})_{\text{historical}}$$

$$(\text{EIM Price})_{2022} = (\text{Mid-C Price})_{2022} \times (\text{EIM Factor})$$

**Q. Why is the update to the EIM price curve forecast necessary?**

A. As described earlier in the testimony, Mid-C transactions are compared to the EIM price curve to determine if MONET sales should be purchased back under EIM pricing, or if MONET purchases should be sold at EIM prices. PGE is shaping the EIM price curve similarly to the Lydia 2.0 shaping of Mid-C forward prices to ensure both price curves are aligned and the EIM methodology produces results consistent with the historical relationship between EIM prices and Mid-C prices.

[9] PGE has derived the EIM price factor within the four wind profile buckets that were developed as part of Lydia 2.0 methodology. Please refer to Section III.B for details on Lydia2.0.

**Q. Please describe in more detail the expanded logic applied to the marginal thermal resource.**

A. In the 2021 forecast, PGE's measurement of EIM benefit identified value if MONET sales could be purchased back at EIM pricing or if MONET purchases could be sold at EIM pricing. However, there are times when the MONET optimization positions the marginal thermal resource in an operating state that could move either direction (i.e., dispatched higher or lower). In these hours, there is the opportunity for EIM benefit to be derived from dispatch in the same direction as the MONET dispatch (e.g., EIM sales in addition to MONET sales in an hour or EIM purchases in addition to MONET purchases in an hour). In the 2022 forecast, PGE's method includes this incremental dispatch benefit in the sub-hourly dispatch savings.

**Q. Does PGE include expected flexible ramping product awards in the 2022 EIM sub-hourly dispatch benefit forecast?**

A. Yes. In PGE's 2021 AUT, parties agreed that PGE increase the 2021 forecasted EIM benefit value to include estimated net flexible ramping benefits based on 2018 and 2019 average settlement data. PGE continues to include estimated net benefits associated with CAISO's flexible ramping product awards. The flexible ramping product awards issued by CAISO are a result of the CAISO-identified need for flexible ramping and the energy bid ranges offered for dispatch in the market from ramp-capable resources.

**Q. How does PGE forecast the 2022 flexible ramping awards?**

A. The 2022 forecast is based on the three-year simple average of historical settlement data from 2018 to 2020 resulting in an estimated flexible ramping product award for 2022 of approximately $0.4 million.

**Q. What is PGE's forecast for the reduction in NVPC from EIM sub-hourly dispatch in 2022?**

A. In this initial filing, PGE's forecast is gross EIM sub-hourly dispatch savings of approximately $5.2 million.

**Q. Will PGE update its forecast during the 2022 GRC proceeding?**

A. Yes. PGE plans to update the benefit estimate during each MONET model run that incorporates forward price curve updates, so that EIM benefits are linked with the current MONET purchase and sales data.

**EIM GHG Awards and Forecast for 2022**

**Q. What is PGE's forecast of GHG award margin (i.e., GHG benefit) in the NVPC forecast?**

A. PGE is forecasting a GHG benefit of $2.7 million, which is predominantly from GHG award revenue assigned to hydro offers in the EIM.

**Q. Please describe PGE's forecast for GHG benefit in its 2022 NVPC forecast.**

A. PGE's forecast for GHG benefit depends on 2020 actual results and the Intercontinental Exchange (ICE) forward price curve for the 2022 California Carbon Allowance. The forecast steps include:

1. Use GHG award price data ($/MWh) and 2020 GHG allowance prices ($/mTCO2[10]) to calculate a weighted implied emission factor (mTCO2/MWh).
2. Using the weighted implied emission factor, apply the ICE forward price curve for the 2022 California Carbon Allowance (ICE product code CB0), adjusted to include California Carbon Offsets (CCOs) used by PGE to comply with California Air

[10] Metric tons of carbon dioxide.

Resource Board (CARB) requirements, to the implied emission factor to calculate a GHG Award Price ($/MWh).

3. Multiply the calculated GHG Award Price ($/MWh) by PGE's 2020 award quantities[11] to create a GHG revenue forecast. This revenue is reduced by a forecast of GHG compliance costs where applicable (i.e., thermal resources assumed to sell GHG in 2022).

**Q. Will PGE update its GHG benefit forecast during the 2022 GRC proceeding?**

A. Yes. PGE plans to update the ICE forward curve consistent with other forward curve updates in the GRC proceeding.

**Q. Please describe PGE's forecast for grid management charges in its 2022 NVPC forecast.**

A. PGE's forecast is $1.1 million. PGE assumes 2020 actual settlement results are a reasonable basis for 2022 grid management charge costs.

**Q. Please summarize PGE's proposal for Western EIM benefits in the 2022 NVPC forecast.**

A. PGE's gross EIM benefit in its 2022 NVPC forecast is $8.2 million. After adjusting for PGE's grid management charge forecast, PGE's net EIM benefit in the 2022 NVPC is approximately $7.1 million.

### D. Gas Storage Optimization Enhancements

**Q. Please summarize PGE's natural gas storage optimization method adopted through Commission Order No. 20-390 (Docket No. UE 377).**

A. In the 2021 AUT, PGE proposed a method to capture potential natural gas storage optimization benefits that could be realized based on North Mist storage injection and

[11] PGE does revise the 2020 award quantity associated with the Pelton Round Butte facility to account for the full Round Butte outage planned for 2022.

withdrawal cycles relative to forward gas prices at the Sumas and Rockies markets and the economic dispatch of the Port Westward/Beaver complex. More specifically, in order to determine a potential gas storage optimization monetary benefit, PGE first evaluated a weighted average cost of gas (WACOG) in storage based on inventory levels and market prices, and planning for gas storage injections in months when the natural gas market prices are cheaper. PGE then withdrew gas from storage during months when natural gas market prices are higher, capturing the economic benefits from running the PW/Beaver complex on cheaper natural gas.

**Q. Has PGE applied refinements to the Gas Optimization method for the 2022 NVPC forecast?**

A. Yes. PGE has applied several refinements to the gas storage optimization method to better reflect actual operations of the North Mist gas storage facility and PGE's firm gas transportation rights, including:

- Refining the Beaver fuel demand calculation to include fuel used when the plant is ramping down after dispatch. Fuel demand is used in the gas storage modeling to calculate the maximum run hours available for Beaver dispatch based on the available fuel supply at the PW/Beaver complex.
- Adding transport costs associated with fuel injections at the Sumas forward price into the North Mist storage WACOG calculation.
- Averaging the daily fuel supply calculation for gas withdrawn from the North Mist storage facility over total monthly days instead of peak days during the month. Gas withdrawals from North Mist are reflected in the available fuel supply at the PW/Beaver complex. Because the fuel supply and demand assumptions are based

on daily averages across each month, using a peak day average for stored gas to meet the daily average fuel demand was incorrectly inflating the average daily fuel available from storage.

- Enhancing the Beaver transition matrix in MONET to more accurately reflect the plant dispatch for months with low average daily run hours (i.e., 1–4 hour intervals). Because MONET was previously constrained to limit Beaver dispatch to a minimum of 4 hours runtime, the gas storage optimization modeling was not reflecting optimal use of available fuel at the PW/Beaver complex when remaining fuel for Beaver resulted in below 4 hours of daily runtime.

**Q. Does PGE propose any enhancements to the gas storage optimization methodology in addition to the refinements described above?**

A. Yes. In addition to the above refinements, PGE is proposing to incorporate the North Mist stored gas into the fuel costs for dispatching the PW1, PW2, and Beaver plants within the MONET model through enhancements to the gas storage optimization modeling. The enhancements refine dispatch costs for the plants based on an economic optimization of the available fuel supply at the PW/Beaver complex to meet expected plant fuel demand. For example, with the enhancements, the fuel supply is optimized to prioritize fueling the most efficient plant with the least expensive source of gas first. Thus, the plant output within MONET and NVPC forecast will reflect dispatch costs based on a blend of fuel from Sumas, Rockies, and North Mist storage.

**Q. Is PGE proposing any changes to the gas resale optimization modeling?**

A. No.

**Q. What is the total gas optimization benefit included in the 2022 NVPC forecast?**

A. PGE includes approximately $4.4 million gas optimization benefit in the 2022 NVPC forecast comprised of: 1) approximately $4.2 million from gas storage optimization, and 2) approximately $0.2 million from gas resale optimization.

### E. Variable Energy Resources Integration

**Q. What updates does PGE propose regarding VER integration?**

A. PGE is proposing to update system reserve requirements to include on-system solar QFs and the solar plus battery component of the Wheatridge facility, in addition to existing wind capacity such that estimated load following and regulation obligations reflect the VERs expected to be online in the 2022 test year. As in previous years, PGE's system reserve requirements are updated using the model set up process for the Resource Optimization Model (ROM). PGE is also proposing a change to Schedule 125, such that it allows for updates to costs associated with integrating all VERs, not only wind as it currently states. As PGE is increasingly seeing a more diverse mix of VERs on its system, it has become important to capture the full effects of these resources in our annual NVPC filings. Please see Exhibit 200 (Pricing) for more details.

**Q. What are load following reserves?**

A. Load following reserves are capacity resources that can ramp up and down to respond to the 5 to 10-minute trends in system load requirements. Increased penetration of renewable resources results in an increased need for load following reserves. Similar to regulation services, providing load following reserves with thermal generation requires plants to operate at less efficient set points, which results in an increase to power costs.

**Q. Please describe the ROM?**

A. The ROM is a production cost model that simulates the dispatch of PGE resources to meet PGE loads and to interact with wholesale energy markets. The ROM incorporates a granular treatment of PGE resource performance, and captures phenomena related to renewable integration and resource flexibility through multi-stage optimal unit commitment and dispatch with imperfect forecast information, sub-hourly timesteps, and operating reserves. The ROM is also used to estimate VER integration costs and flexibility value of candidate new resources in the IRP process. As part of the ROM set up process, system reserves obligations such as regulation and load following are updated for the year of interest.

**Q. When did PGE start to forecast costs associated with self-integration of wind generation?**

A. In 2007, given projections for a significant increase in wind generating resources, PGE began efforts to forecast costs associated with the self-integration of wind generation, which we named the Wind Integration Study. These efforts entailed developing detailed data and optimization modeling of PGE's system using mixed integer programming. PGE intended this integration study to be the initial phase (Phase 1) of an ongoing process to estimate wind integration costs and refine the associated model. Between 2009 and 2016 PGE conducted Phases 2 to 5[12] of the Wind Integration Study including additional refinements for estimating PGE's costs for self-integration of its variable resources, including reserve requirement formulations for load following, regulation, and imbalance reserves.

[12] Phase 2 began in October 2009 due to the expectation that the price for wind integration services, as provided at that time by BPA, would increase in the future, as growing wind capacity in the Pacific NW would exceed the potential for BPA's finite supply of wind-following resources. PGE conducted a Phase 3 internal study to inform the decision for the BPA fiscal year 2014-2015 election period for wind integration services. PGE conducted Phase 4 in its 2013 IRP and Phase 5 in the 2016 IRP.

**Q. Why didn't PGE include solar generation in its forecast of self-integration costs associated with variable resources during early phases of the wind integration study?**

A. At the time we started the Wind Integration Study in 2007, there was minimal generation from renewable resources other than wind. This continued to be the case during subsequent updates to the study until mid-2010s, when increasing amounts of solar generation started to integrate into PGE's systems.

**Q. Did PGE introduce solar generation in Phase 5 of its forecast of costs associated with the integration of variable resources?**

A. Yes. During the 2016 Integrated Resource Planning process,[13] PGE introduced Phase 5 of the study, which accounted for solar generation. PGE also updated the name of the study to Variable Energy Resource Integration Study. In Phase 5, PGE refreshed integration cost estimates and evaluated the impact of increasing levels of VERs, including solar generation. PGE continued to utilize the ROM to estimate integration costs associated with VERs in the 2019 IRP (LC 73).

**Q. Why do you propose this update at this time?**

A. As noted above, starting mid-2010s and continuing into 2021 and 2022, a significant number of solar QF resources have and are expected to enter into PGE's portfolio. For example, the initial filing of the 2017 AUT contained an annual average of approximately 10 MWa of solar generation, whereas the initial 2022 GRC filing includes approximately 126 MWa; an increase of approximately 116 MWa over five years. Additional solar projects are expected to come online in 2022 as part of the Community Solar Program. Therefore, PGE updated

[13] Commission Order No 17-386 acknowledged PGE's 2016 IRP in Docket No. LC 66.

the ROM volumes to estimate PGE system reserve requirements that account for the additional solar resources expected to be online in 2022.

**Q. Has PGE previously proposed an update to VER volumes in ROM to reflect the addition of new PGE renewable resources and on-system solar projections?**

A. Yes, in the 2021 test year AUT (UE 377) PGE proposed a change to Schedule 125 language to allow for the update of VER integration costs as opposed to only wind integration costs. PGE also proposed an update to the load following and regulating margin obligations to reflect the inclusion of the Wheatridge wind facility and on-system solar resources. Parties agreed that PGE update the VER volumes used to calculate reserve obligations to reflect the inclusion of the Wheatridge wind facility. Additionally, parties also agreed to maintain the Schedule 125 language unchanged within that proceeding.

**Q. What is power cost impact for adding solar generation to the ROM modeling of system reserve requirements?**

A. The estimated increase in 2022 NVPC is approximately $0.8 million.

## F. Other Items

### 1. Wheatridge Solar and Battery (Wheatridge 2.0)

**Q. What does Wheatridge 2.0 consist of?**

A. Wheatridge 2.0 represents the 50 MW fully integrated, RPS-compliant solar facility, plus the 30MW/4-hour battery storage facility. The facility is expected to come online prior to the beginning of 2022. The solar and storage facilities are operated pursuant to the Power Purchase Agreement (PPA) with NextEra. PGE provides the PPA through the MFRs.

**Q. How does PGE model the solar component of Wheatridge 2.0?**

A. The net capacity factor and the hourly generation profile for the solar array is based on generation data provided by the bidder in PGE's Renewable RFP that resulted in the selection of Wheatridge as the least cost, least risk bid. PGE provides additional information in the MFRs.

**Q. How does PGE model the battery component of Wheatridge 2.0?**

A. PGE will operate the battery component of Wheatridge 2.0 in accordance with the terms of the PPA. Specifically, the battery storage facility has one use case for the battery operation. Modeling of this use case under average conditions in MONET has the battery charging during sunlight hours, per the solar generation profile. Then, when the battery is fully charged or no longer charging for that day, four hours are maintained at the highest level of charge achieved, and then the battery fully discharges.

**Q. What impact does the Wheatridge 2.0 enhancement have on PGE's initial 2022 NVPC forecast?**

A. The addition the Wheatridge 2.0 in MONET increases PGE's initial 2022 NVPC forecast by approximately $3.5 million.

### 2. Pacific Northwest Coordination Agreement Study Update

**Q. Please describe the update to include the new Pacific Northwest Coordination Agreement (PNCA) study.**

A. Under the PNCA, the Northwest Power Pool (NWPP) conducts an 80-year regulation study called the Headwater Benefits Study (HB Study), based on a regulation model whose objective function is to maximize the firm energy load-carrying capability of the Northwest system as a whole. This model considers the loads and thermal resources of regional entities, as well as hydro resources. The model produces a simulated regulation of 80 water years under historical stream flows,[14] which we then use, with a set of adjustments, to develop the average hydro energy inputs to MONET.

**Q. Does PGE include the PNCA study update in the April 1 initial AUT filing?**

A. No. During the validation of the 2019-2020 HB Study results, PGE uncovered an issue affecting the upstream storage flows to the Mid-C projects in a manner that was inconsistent with the releases at or above the Mid-Columbia projects or the storage flows downstream to McNary. This seems to be a material error in the study**.**

**Q. Will PGE include the updated PNCA study in a future MONET update?**

A. Possibly. PGE is currently investigating the issue that was uncovered during validation and, should the issue be resolved in due time, we will include the update in the July MONET update.

### 3. QF Energy Derate and Tracker Mechanism

*a) QF Energy Derate*

**Q. Please describe the QF energy derate.**

A. Pursuant to Commission Order No. 19-329 issued in PGE's 2020 AUT (UE 359), PGE calculates a derate percentage to adjust the forecast energy generation of new QFs expected to achieve commercial operation in the test year. Parties to UE 359 agreed that PGE will calculate the QF energy derate based on the most recent four-year historical annual average of actual versus projected QF costs.

**Q. What is the QF energy derate for the 2022 NVPC forecast?**

A. PGE will not apply a derate percentage to the new QFs expected to come online in 2022 because actual power costs associated with QFs that achieved COD between 2017 and 2020

[14] Using stream flow data from August 1928 through July 2008.

was 20 percent higher than new QFs projected to come online in the same period in our annual NVPC forecasts.

*b) QF Track and True Up Mechanism*

**Q. Please provide some background regarding the QF track and true up mechanism.**

A. In our 2019 GRC (UE 335) the Commission adopted a stipulation where parties agreed that PGE will track the actual online dates of all newly forecasted QFs with the purpose of either refunding to, or collecting from customers, the difference in NVPC due to forecasted versus actual online dates. Subsequently, parties to PGE's 2020 AUT (UE 359) further refined the QF track and true up mechanism to also account for the variance in actual QF generation compared to projected generation from 2020 onwards.

**Q. Is PGE proposing any changes to the QF track and true up mechanism in this proceeding?**

A. No. PGE believes the current setup for the QF track and true up mechanism provides the simplest, most straightforward, and most precise method for ensuring that accurate online delivery dates are properly reflected in customer prices. Given the obligation under federal and state laws for the load serving utility to purchase output from QFs, we believe that neither PGE nor its customers should bear the risk of forecasting an online date of delivery. The QF tracking mechanism ensures that neither PGE nor its customers will bear the risk of QF PPAs not meeting their stated COD.

**Q. Please explain how you determined the QF refund.**

A. First, PGE tracked the online dates and actual generation of all QFs forecast to achieve COD in 2020. PGE then re-ran the final November 16 NVPC MONET forecast for the 2020 test year after: 1) replacing the estimated QF CODs and with actual recorded CODs; and 2) replacing the 2021 forecast generation for projects subject to the 54 percent derate applied pursuant to Commission Order No. 19-329 with actual project generation. From this, PGE determined the power cost variance to be refunded to customers by comparing the original November 15 NVPC MONET forecast for the 2020 test year with the revised version described above.

**Q. Does PGE include a QF refund associated with the QF track and true up mechanism in the 2022 AUT?**

A. Yes. For the initial 2022 NVPC forecast PGE includes a refund of approximately $1.9 million associated with QFs forecast to come online in 2020 that experienced delays in their expected COD. However, the impact associated with the QF tracker for the 2022 NVPC forecast represents an increase of approximately $1.4 million compared to the 2021 NVPC forecast because the amount refunded in the 2021 AUT was approximately $3.3 million.

### 4. <u>Pelton Round Butte (PRB) 2022 Maintenance Outages and Ownership Percentage Change</u>

*a) Pelton-Round Butte 2022 Maintenance Outage*

**Q. Please describe the PRB maintenance outages that will occur in 2022.**

A. The PRB facility includes three hydro units at the Round Butte dam (338 MW) and three hydro units at the Pelton dam (110 MW), plus the Pelton Regulating Dam (18.9 MW). During 2022 there will be two significant outages at the Round Butte hydro facility and one significant outage at the Pelton hydro facility, in addition to the plants' annual planned maintenance outages:

1. Round Butte Outages:

a. Round Butte Hydro Unit 1 will be offline for approximately six weeks in late Q3-early Q4 of 2022 for a governor/exciter upgrade. The outage will impact the generation output at the Round Butte facility.

b. All three Round Butte hydro units will be offline for approximately four weeks in late Q3 - early Q4 of 2022. This maintenance outage is required for upgrading the station service 480v switchgear that provides all station service to Round Butte Powerhouse. The Round Butte hydro units will be completely de-energized for the duration of the maintenance outage so that in addition to zero generation from Round Butte, the ancillary services capabilities provided by the Pelton-Round Butte hydro facility will be impacted during this time.

2. The Pelton hydro unit 2 will be offline for approximately six months in 2022 for extensive maintenance work needed for a generator rewind and governor/exciter upgrade. Similar to the Round Butte outage, this Pelton outage will impact the ancillary services capabilities at the PRB hydro facility.

**Q. What ancillary services does the PRB hydro facility provide?**

A. The PRB hydro facility provides the following ancillary services:

- Regulating Reserves – capacity that must react to load changes every few seconds. The capacity may be ramped up or down every few seconds to essentially follow the changes in moment-to-moment load.
- Load Following Reserves – capacity that can respond to the 5-to-10 minute trends in system load requirements.
- Spinning Reserves – the portion of contingency capacity which is online and synchronized to the system, capable of responding to generation or transmission

outages (contingencies). This capacity must be operating with unused capability held in reserve with the ability to ramp up.

- Non-Spinning Reserves – the portion on contingency capacity which may be offline but can start, synchronize, and be online in ten minutes (also called “quick start”). This capacity must be held in reserve with the ability to ramp up.

**Q. Why is the availability of ancillary services impacted by the maintenance outages described above?**

A. The availability of ancillary services at the Pelton and Round Butte hydro units will be impacted due to the water management needed to ensure safe plant operations. More specifically, when the Round Butte hydro units are not operating, water must be released past the dam via the spillway (i.e., spilled), filling the downstream pond at the Pelton dam, impacting the availability of ancillary services at both the Pelton and the Round Butte hydro units. Because the pond at the Pelton dam is very small, the water discharge is limited in how much it can fluctuate from hour to hour to provide ancillary services, while maintaining the Pelton pond within license limits. When the Round Butte water is spilled, the Pelton pond is even more limited in how much it can fluctuate.

**Q. Please elaborate.**

A. When the Pelton hydro facility is operating with all three units available, the water flow out of Pelton is generally matched with the water flow out of Round Butte, when Round Butte is fully operating. When the water flow is not matched between Round Butte and Pelton, the Pelton pond water discharge will fluctuate to accommodate the difference in water flow. Ancillary services at both Pelton and Round Butte hydro units are impacted as they require pond space to manage the change in flow. Because the Pelton pond is small, it does not have the capacity to physically manage the water flow necessary to provide ancillary services when either a substantial portion of the Pelton or Round Butte hydro units are offline for extended periods of time. Figure 5 below provides a schematic of the water flow at the Pelton-Round Butte hydro facility.

**Figure 5: Pelton – Round Butte Water Flow**


**Q. How does the PRB maintenance outage impact the 2022 NVPC initial forecast?**

A. The PRB maintenance outage is causing an increase of approximately $3.6 million in the 2022 NVPC initial forecast due to the loss of energy output and the loss of ancillary services at these powerhouses. Ancillary Services lost at Pelton and Round Butte will be carried at other plants. If the plants are thermal there is increased cost due to the lost generation caused by backing the units down or by bringing the units online.

*b) Pelton-Round Butte Ownership Percentage*

**Q. What is PGE's ownership percentage at PRB?**

A. PGE currently owns 66.7 percent of PRB. The remaining 33.3 percent is currently owned by the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes).

**Q. Does PGE expect that the ownership percentage will change?**

A. Yes. The Tribes have the contractual option to increase their ownership share at PRB from 33.33 percent to 49.99 percent starting with January 1, 2022 and have expressed the intention to exercise this option.[15,16]

**Q. Did PGE adjust the PRB ownership percentage for the 2022 NVPC initial filing?**

A. Yes. Based on information known at this time we expect the Tribes to exercise their option. Therefore, we reduced PGE's share at PRB. The power cost impact is a $9.3 million increase to the 2022 NVPC forecast.

### 5. <u>BPA rate case</u>

**Q. Does PGE expect an update to BPA's transmission rates for the 2022 test year?**

A. Yes. BPA is currently conducting a rate case (BP-22) to set power, transmission, and ancillary and control area service rates for the fiscal year 2022-2023 rate period. This will include updates to both point-to-point (PTP) and scheduling, dispatch, and control rate (SCD) transmission rates. The BP-22 Rate Case began on December 1, 2020 and will conclude when BPA issues the final Record of Decision in late July 2021 with updated rates effective October 1, 2021.

**Q. Did PGE estimate a BPA transmission rate increase in the 2021 NVPC forecast?**

A. Yes. PGE estimated a rate increase of approximately 4.0 percent for PTP and 7.6 percent for SCD transmission rates for the period October 1, 2021 through December 31, 2021. This estimate was based on the current rate multiplied by the average rate escalation for the nine BPA transmission rate case periods starting with 2002.

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[15] The property sale application related to the PRB facility was approved by the Commission through Order 00-459 in Docket No. UP 176. Please see at: [ISSUED March 24, 1999 (state.or.us)]
[16] Please see the Pelton-Round Butte Agreement between PGE and the Tribes in the MFRs, Volume 5-Contracts.

**Q. Will PGE update the BPA PTP and SCD transmission rates in this filing?**

A. Yes. PGE will update the 2022 BPA transmission rates based on BPA's final Record of Decision expected to be published in the July 2022 timeframe.

**Q. Does PGE expect the outcome of the BPA rate case to impact other NVPC items in this filing?**

A. Possibly. Other than a potential change in transmission rates, the most significant impact could be due to potential changes that BPA will make to its 30/15 committed scheduling option provided to Variable Energy Resource Balancing Service (VERBS) customers, including PGE.

**Q. Please explain the 30/15 committed scheduling option for a wind resource?**

A. Under the 30/15 committed scheduling option, PGE makes four wind schedule changes per hour.[17] BPA has also offered 30/60 and 40/15 committed scheduling options in the past. Both of these options are more expensive than the 30/15 committed scheduling option, because BPA is responsible for more of the intra-hour variability of a customer's resource placed on the BPA BAA.

**Q. How will the 2022 NVPC forecast be impacted if BPA makes changes to or discontinues its 30/15 scheduling option, as part of VERBS?**

A. If BPA's proposed changes to VERBS are implemented, PGE would expect a change in BPA's scheduling tariff that could impact the reserve quantities PGE needs to hold for regulation and load following as part of VER integration.

[17] PGE submits a schedule 30 minutes prior to each 15-minute schedule interval for the forecast of each plant's output. The forecast is based on BPA's persistence forecast, which is the one-minute average of generation from 31 to 30 minutes before each scheduling period. For example, PGE would submit a schedule for Wheatridge at 2:30 p.m. for generation that will occur from 3:00 p.m. to 3:15 p.m. The schedule is based on a forecast that is derived by taking the average of the Wheatridge generation from 2:29 p m. to 2:30 p m.

**Q. Does PGE assume any impact due to changes to BPA committed scheduling options in this initial 2022 NVPC forecast?**

A. No. Currently, PGE is monitoring BPA's rate case and will make any necessary updates to the 2022 NVPC forecast in subsequent MONET updates.

### 6. <u>Transmission Resale Revenue Forecast</u>

**Q. How does PGE forecast transmission resale revenues in the 2022 NVPC forecast?**

A. For the 2022 NVPC forecast PGE will continue to assume a fixed amount of 300 MW transmission capacity is available for resale in Q1, Q2, and Q4 of 2022. PGE does not assume any transmission capacity available to resale in Q3 due to expected transmission needs for PGE's load service obligation or PGE's Market Sales Obligation. In actual operations PGE does not have a secured long-term transmission resale agreement and all transmission resales are pursued on a short-term basis (less than one year). Often, transmission resales represent an instrument to optimize PGE's transmission needs to reliably serve our load and is based on the economics of PGE's generation plants.

**Q. Has PGE updated any input to the 2022 transmission resale revenue forecast?**

A. Yes, PGE increased the market price applied to transmission resale transactions from $1.05/MWh to $1.5/MWh to align with average market prices seen in actual operations.

**Q. What is the power cost impact from updating the transmission resale price?**

A. The 2022 NVPC forecast is reduced by approximately $0.9 million.

### 7. <u>Beaver Plant Upgrade</u>

**Q. Please describe the Beaver Modernization Project.**

A. The Beaver Modernization Project will upgrade the existing Beaver gas turbine combustion systems from a dual fuel system to a single fuel dry low NOx system to reduce the overall emissions for the plant as turbines are upgraded. The single fuel will be natural gas and the upgraded units will be prevented from operating on fuel oil as an alternative. The combustion upgrade will allow for greater operational flexibility while meeting PGE's commitment to reduced emissions at the site.

**Q. Why is PGE upgrading the Beaver gas turbine combustion systems?**

A. In June 2020, PGE made a voluntary commitment to the Oregon Department of Environmental Quality (DEQ) to reduce annual allowable emissions of Regional Haze pollutants at the Beaver Plant to support DEQ's Regional Haze second planning period. Environmental regulations and standards have become more stringent over time, as has the expectations of customers about PGE's environmental impact and stewardship. Current emissions from the Beaver turbines remain similar to the emissions rates when originally converted to allow combustion of natural gas in the 80's. Post project emissions will be significantly lower and more aligned with modern turbine emissions.

**Q. What is the current estimated timeline for the project?**

A. The project is expected to start in spring 2022, beginning with a single upgrade to Beaver Unit 6 for 2022, with expectation of completing upgrades to all Beaver units by the end of 2025.

**Q. Is this upgrade expected to change Beaver's operational characteristics?**

A. Yes. The turbine upgrades will impact Beaver's plant parameters by slightly increasing the plant's capacity and heat rate.

**Q. What is the NVPC impact due to the Beaver Unit 6 upgrade work?**

A. The power cost impact associated with the Beaver parameter update resulting from the upgrade is not material, representing an approximately $60 thousand decrease to the 2022 NVPC forecast.

### 8. Faraday Repowering Project

**Q. What is the scope of the Faraday Repowering Project?**

A. PGE is upgrading the Faraday Hydro facility to ensure safe operations and plant reliability. Prior to the upgrade, the Faraday hydro facility consisted of five hydro units (Units 1 through 5), originally constructed in 1907, and a sixth unit (Unit 6), placed in service in 1965. Units 1 through 5 were housed in an un-reinforced masonry building which was seismically unfit and subject to flooding, requiring significant investment to continue safe and reliable operation of the original development. Unit 6 is in good condition and did not require structural upgrades. As part of the Faraday Repowering Project, PGE is replacing Units 1 through 5 with a new powerhouse that will consist of two-higher efficiency turbines (Faraday Units 7 and 8) housed in a reinforced concrete structure with flood protection. The upgraded Faraday Hydro facility will optimize generation potential for the remaining license period.

**Q. Did PGE update the Faraday H/K coefficient to reflect the expected increased efficiency of the upgraded Units 7 and 8?**

A. PGE did not update the H/K coefficient for the initial April 1 NVPC filing. However, PGE is currently working with the provider of the Faraday Units 7 and 8 turbines to adjust the H/K coefficient to reflect an updated view of the plant capability. PGE will update the H/K input to the plant parameters in a future MONET update.

**Q. Is the expected incremental generation at Faraday eligible to generate Production Tax Credits (PTC)?**

A. Yes. In PGE's 2021 AUT (Docket No. UE 377) parties agreed that PGE will reduce its 2021 NVPC forecast by approximately $0.6 million to reflect forecasted PTC benefits associated with Faraday incremental generation. PGE continues to include the $0.6 million PTC benefit in the initial 2022 NVPC forecast. However, PGE will update the PTC benefit amount based on the final forecasted output of Faraday Units 7 and 8 in a future MONET update.

### 9. <u>Blue Marmot QF Projects Aggregation</u>

**Q. Please provide a brief explanation of the Blue Marmot projects.**

A. The Blue Marmot projects are five 10MW solar arrays located within a larger project boundary. The projects are located near Lakeview, Oregon and interconnect to the PacifiCorp West (“PACW) transmission system. The projects are being developed by EDP Renewables North America (“EDPR”) and were submitted to PGE as Qualifying Facilities under PGE’s Schedule 201.

**Q. What is the current status of the Blue Marmot projects?**

A. The projects are currently in advanced development. EDPR has executed interconnection agreements, confirmed PACW transmission reservations that have subsequently been deferred to align with expected commercial operations dates, and resumed its Energy Facilities Siting Council (“EFSC”) permitting process in 2020. The scheduled commercial operations dates of the project currently vary between September 2022 and December 2022.

**Q. Why is PGE providing testimony on these projects?**

A. EPDR recently approached PGE inquiring about the ability to aggregate the five individual 10MW projects into a single 50MW project in exchange for passing the savings back to PGE customers via a reduction in the PPA pricing.

**Q. Is EDPR proposing to build a different project from the Blue Marmots?**

A. No. One of the five Blue Marmot locations has enough viable land to construct a 50MW array. EDPR is proposing to construct a single 50MW solar array within the project boundary, rather than five separate smaller arrays, but continue to use the same project permits, transmission, and interconnection agreements. Effectively, EDPR is proposing to convert the five individual Schedule 201 projects to a single Schedule 202 project, but maintain the critical aspects, such as capacity and expected energy, as the individual projects. This is distinct from a developer that submits a 10MW project and later requests to increase the capacity or the expected energy but seeks to preserve the original pricing of the 10MW project.

**Q. Have PGE and EDPR reached an agreement to aggregate the PPAs?**

A. PGE and EDPR have reached agreement on a non-binding term sheet capturing the major commercial terms and conditions. Parties are exchanging a draft Schedule 202 agreement in order to finalize the remaining terms before working through their respective internal approval processes.

**Q. Why is PGE filing testimony on the Blue Marmots at this stage if the contract is not yet final?**

A. PGE wanted to provide this testimony in our initial filing in order to allow time for parties to review and respond accordingly. As we stated above, the key terms and conditions have been agreed to and the parties are working diligently on a final contract.

**Q. Please summarize the key components of the agreement.**

A. Under the proposed agreement, PGE and its customers would receive a price decrease of [confidential] [redacted] [confidential] in all hours from the Blue Marmot's effective Schedule 201 pricing. In addition to this price decrease, PGE also negotiated several other beneficial commercial terms for PGE and its customers:

- [confidential] [redacted]

- [redacted]
- [redacted]
- [redacted] [confidential]

**Q. Does the new agreement impact aspects of Commission Order No. 19-322?**

A. No. Under the new agreement, the Blue Marmots are still limited to the use of 40MW of power delivered to the PACW.PGE interface, which PGE uses for EIM participation, and the remaining 10MW delivered via the BPAT.PGE interface.

**Q. Did you update the PPA with EDP for the initial April 1 filing?**

A. No. Due to the ongoing negotiations and the timing of preparing the initial filing, we were unable to update the initial filing to incorporate this change. We plan to make the change in a subsequent MONET update.

**Q. What is the current impact of the Blue Marmot projects in this filing?**

A. The current impact of the Blue Marmot projects is $424,000 for 2022. Under the new agreement, the impact for 2022 is estimated to be $90,000, a $334,000 reduction to forecast power costs.

**Q. How does this compare to an estimated full year impact?**

A. An estimated 2023 full-year impact of these five projects, under the current agreement is $9.1 million, while under the new proposed agreement, the 2023 impact is estimated to be $7.2 million: a savings of approximately $1.9 million.

### 10. Wheatridge Facility Performance Report

**Q. Please provide some background regarding the Wheatridge facility performance report.**

A. Pursuant to Commission Order No. 20-321 in Docket No. UE 370, PGE is now required to submit a report as part of its annual power cost filing that details the performance of the Wheatridge facility. Furthermore, PGE was directed to work with parties to that proceeding on the format and particulars of the report.

**Q. Has PGE met with parties to discuss the particulars of this Commission request?**

A. Yes. Parties agreed that as part of its April filing, regardless of whether it is a GRC or AUT year, PGE will provide the following annual and cumulative information pertaining to the Wheatridge facility:

- Forecast and actual (where applicable) expense and capital amounts specific to the Wheatridge facility;
- Historical generation, including an annual capacity factor; and
- Production Tax Credits generated and utilized.

**Q. How should parties expect this information to be provided?**

A. PGE will be providing this information as part of its April updates and will include the above referenced data within the Volume 11 – Historical Data MFRs normally provided within the annual NVPC proceeding. For the 2022 AUT, PGE is providing the Wheatridge facility performance report in the April 15 MFR filing.

# IV. 2022 Load Forecast

**Q. Please summarize PGE's forecast for its 2022 retail load.**

A. Table 3 below summarizes actual and forecast deliveries to various customer groups from 2020 through 2022 in thousands of MWhs at average weather conditions. The 2022 forecasted deliveries of 20,497 thousand MWhs are 2.4 percent higher than the forecasted 2021 deliveries driven by offsetting impacts in residential and commercial energy deliveries as usage moves from the home to the workplace following the COVID-19 pandemic and continued growth in energy deliveries to the industrial customer class.

**Table 3**
**Retail Energy Deliveries: 2020-2022**
**(cycle month energy in thousands of MWhs, weather-adjusted)(3)**

| | 2020 Actual (1) | 2021 Forecast (2) | 2022 Forecast |
|---|---|---|---|
| Residential | 7,765 | 7,847 | 7,557 |
| General Service | 6,804 | 6,860 | 7,169 |
| Industrial | 4,908 | 5,269 | 5,727 |
| Lighting | 52 | 47 | 44 |
| Total Retail | 19,529 | 20,023 | 20,497 |

(1) 2020 actual loads are weather-adjusted according to UE 335 weather methodology
(2) 2021 contains one month of weather-adjusted actuals and remainder of year updated forecast
(3) Numbers may not total due to rounding.

**Q. Does this 2022 forecast include all loads?**

A. Yes. The forecast includes both PGE cost-of-service loads and deliveries of energy to customers under Schedules 485/489/689.

**Q. Does PGE's cost-of-service load forecast assume that any long-term opt-out customers return to a cost-of-service rate in 2022?**

A. No. PGE does not assume that certain long-term opt-out customers return to cost of service in 2022. PGE assumes all long-term opt-out and new load direct access customers remain on direct access. PGE does assume that short-term (one-year) opt-out customers return to cost-of-service in 2022.

**Q. If customers select a long-term opt-out program for 2022, will PGE adjust the load forecast?**

A. Yes. PGE will adjust the 2022 cost-of-service load forecast accordingly, as specified in Schedule 125.

**Q. Was the 2022 forecast developed using the same models used in Docket No. UE 377?**

A. Yes. The same forecast models used in UE 377 were updated with recent actuals through January 2021, the March 2021 (most recent) economic forecasts from the Oregon Office of Economic Analysis, and an updated energy efficiency forecast from the Energy Trust of Oregon.

**Q. What load do you use in your 2022 test year power cost forecast?**

A. The load listed in Table 3 represents total system load on a cycle month basis at the customer meter as used to calculate rates. The load used to generate power costs in MONET is the cost-of-service load on a calendar month-basis. Table 4 below reconciles the total system load in Table 3 with the cost-of-service load on a calendar month-basis.

**Table 4**
**Total System Load on Cycle Month at Meter to Cost-of-Service Load on Calendar Month at Meter: 2022**
**(thousand MWh)**

| | |
|---|---|
| Total System Load (cycle month) | 20,497 |
| Add: Cycle to Calendar Month Difference | 12 |
| Total System Load (calendar month) | 20,509 |
| Less: Schedules 485/489/689 | (2,198) |
| Cost-of-Service Meter Load | 18,310 |

**Numbers may not total due to rounding.*

**Q. What is the corresponding initial cost-of-service bus bar load forecast for 2022?**

A. With the addition of line losses to Table 4, the initial bus bar load forecast for 2022 is 19,437 thousand MWh, or 2,219 MWa. This load is the basis for the hourly MONET load input data.

## V. Comparison with 2021 NVPC Forecast

**Q. Please restate PGE's initial 2022 NVPC forecast.**

A. The initial forecast is $511.8 million.

**Q. How does this 2022 NVPC forecast compare with the 2021 forecast used to develop NVPC in UE 377 and approved in Commission Order No. 20-390?**

A. Based on PGE's final updated MONET run for the 2021 test year, the NVPC forecast was $457.9 million, or $24.4 per MWh. The initial 2022 forecast is $511.8 million, or $26.3 per MWh, which is approximately $1.9 per MWh more than the final forecast for 2021.

**Q. What are the primary factors that explain the increase in NVPC forecast for 2022 versus the NVPC forecast for 2021 in UE 377?**

A. Table 5 below lists changes in NVPC by factor between 2022 and 2021.

**Table 5**
**Forecast Power Cost Difference 2022 vs. 2021 ($ Million)**

| **Factor** | **Effect ($M)** |
|---|---|
| Hydro Cost and Performance | $ (2.1) |
| Coal Cost and Performance | $ (0.4) |
| Gas Cost and Performance | $ (11.2) |
| Wind Cost and Performance | $ (1.5) |
| Contract and Market Purchases | $ 39.3 |
| Market Purchases for Load Change | $ 31.1 |
| Transmission | $ (1.3) |
| **Total** | $ 53.9 |

* *Numbers may not total due to rounding.*

The primary factors contributing to the increase in NVPC include: 1) an increase in costs due to higher average unit price applied to energy contracts; 2) an increase in costs due to reduced revenues from market sales caused by changes in market price; and 3) an increase in costs associated with additional market purchases due to a projected load increase in 2022. The NVPC cost increase due to the factors described above is partially offset by increased dispatch from our hydro, coal, gas, and wind plants, compared to the final 2021 NVPC forecast.

As we discussed in Section III of our testimony, our load forecast for cost-of-service energy is approximately 2,219 MWa, an increase of 78 MWa from the 2021 NVPC forecast in PGE's most recent NVPC proceeding in UE 377.

# VI. Qualifications

**Q. Ms. Vhora, please describe your qualifications.**

A. I received a Bachelor of Technology degree in Metallurgy and Material Science from College of Engineering, Pune (CoEP), India in 2014 and a Master of Financial Mathematics degree from North Carolina State University in 2015. I have been employed at PGE since 2019 as a Senior Financial Analyst on the Power Cost Forecasting and Analysis team and my current position is as Manager, Power Cost Forecasting and Analysis. Prior to joining PGE, I worked at Emerald Kalama Chemicals, from 2016 to 2019, as a Financial Analyst in the Financial Planning and Analysis (FP&A) department.

**Q. Mr. Outama, please describe your qualifications.**

A. I received a Bachelor of Science degree in Accounting from University of Washington in 1996. I have over 22 years of experience with PGE working in accounting, financial planning, risk management, structuring and origination, and power operations. I have been involved in originating and pricing of custom products, asset acquisitions, as well as ad hoc project management including the 2012 Request for Proposals on behalf of PGE's customers. I became the General Manager of Power Operations in August 2020. Prior to this I held positions as was Director of Financial Forecasting & Planning and Manager, Origination, Structuring and Fundamental Analysis.

**Q. Mr. Batzler, please describe your qualifications.**

A. I received a Bachelor of Arts degree in Radio and Television from San Francisco State University in 1997 and a Master of Business Administration degree from Marylhurst University in 2011. I have been employed at PGE since 2006, working in various departments including Meter Reading and Human Resources. I have worked in the Rates and Regulatory Affairs department since 2012.

**Q. Does this conclude your testimony?**

A. Yes.

## VII. List of Exhibits

| **Exhibit** | **Description** |
|---|---|
| 101 | List of MFRs per Commission Order No. 08-505 |
| 102C | December 16, 2020 NVPC Workshop Presentation |
| 103C | January 25, 2021 NVPC Workshop - EIM presentation |
| 104C | January 25, 2021 NVPC Workshop – PW/Beaver Gas Supply and Transmission Resale Revenue Forecast |
| 105C | March 5, 2021 NVPC Workshop Presentation |

# Minimum Filing Requirements
# July 7, 2008

## General

The Minimum Filing Requirements (MFRs) define the documents to be provided by PGE in conjunction with the Net Variable Power Cost (NVPC) portion of the Company's initial (direct case) and update filings of its General Rate Case (GRC) and/or Annual Update Tariff (AUT) proceedings.

The term "Supporting Documents and Work Papers" as used here means the documents used by the persons doing the NVPC forecasting at PGE to develop the final inputs to Monet and the final modeling in Monet for each filing. This may include such items such as contracts, emails, white papers, studies, PGE computer programs, Excel spreadsheets, Word documents, pdf and text files. This will not include intermediate developmental versions of documents that are not used to support the final filing. Documents will be provided electronically where practical.

In cases where systems change or are replaced in the future, such as BookRunner, the MFRs will continue to provide substantially the same information as provided in PGE's 2009 GRC (UE-198).

PGE will take reasonable steps to ensure that the MFRs can be made available to CUB and ICNU at the time of the filing, rather than these parties having to wait for the OPUC to approve the protective order in the case.

## Delivery Timing

In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing), at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:

- Summary Documents (Items 1-6)
- Modeling Enhancements and New Item Inputs (Item 14) – not applicable in AUT year
- Miscellaneous Item 15d - re: Testimony and Exhibits provided on the CD

The remainder of the Direct Case Filing MFRs will be delivered with the initial filing if practical, or no later than fifteen days after the filing (e.g. March 15 in a GRC year, April 15 in an AUT year).

For all update filings, Update Filing MFRs will be delivered with the update filing with the following exception. For the April 1 GRC Update Filing in a GRC year, the delivery of Item 23 will be made with the filing if practical, or no later than fifteen days after the filing (e.g. April 15).

# Direct Case Filing

Applicability

- Applies to GRC Initial Filing (e.g. February 28) in a GRC year
- Applies to AUT Initial Filing (i.e. April 1) in a non-GRC year

Summary Documents

1. Monet model for the final step
2. Hourly Diagnostic Reports for the final step
3. Step Log showing NVPC effects of modeling enhancements, modeling changes, addition of new items or removal of items from the prior year rate proceeding (GRC or AUT), and other major updates that PGE believes the parties would want to see identified separately, such as updating the hydro study.
4. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
5. Executable files, any other files needed to run Monet, and installation instructions
6. Identification of the operating system PGE uses to operate Monet

Supporting Documents and Work Papers for the Following

7. Forward Curve Inputs. Consists of:
    a. Electric curve extract from Trading Floor curve file
    b. Gas curve extract from Trading Floor curve file
    c. Canadian/US Foreign exchange rate (F/X Curve) from Risk Management
    d. Model run for hourly shaping of monthly on/off-peak electric curve (Lydia Program)
    e. Oil forward curve
8. Load Inputs. Consists of:
    a. Monthly load forecast from Load Forecast Group
    b. Hourly load forecast from Load Forecast Group
    c. Copy of the loss study used by Load Forecast Group to develop busbar load forecast
9. Thermal Plant Inputs
    a. Capacities
    b. Heat Rates
    c. Variable O&M

        This includes any other cost or savings components modeled as part of Variable O&M, such as incremental transmission losses, $SO_2$ emission allowances (emission allowance $/ton price forecast, plant emission factors lb/MMBtu), etc.
    d. Forced outage rates
    e. Maintenance outage schedules and derations
    f. Minimum capacities
    g. Operating constraints
    h. Minimum up times
    i. Minimum down times
    j. Plant testing requirements
    k. Oil usage volumes
    l. Coal commodity costs
    m. Coal transportation costs
    n. Coal fixed fuel costs classified as NVPC items

        Includes items such as: Colstrip Fixed Coal Cost and the following Boardman costs: Rail Car Mileage Tax, Coal Sampling, Rail Car Lease, Rail Car Maintenance, Trainset Storage Fee, and Coal Car Depreciation
10. Hydro Inputs
    a. Monthly energy for all Hydro Resources

        This will include the results of PGE's most current study using the Pacific Northwest Coordination Agreement (PNCA) Headwater Benefit Study. Note that this program is not the property of PGE and should be obtained from the Northwest Power Pool. Provide the PGE version of the PNCA model inputs, so that if the Parties obtain the PNCA model, they would have the inputs needed to reproduce PGE's study.
    b. Description of logic for hourly shaping where applicable
    c. Usable capacities where applicable
    d. Operating constraints modeled
    e. Hydro maintenance derations
    f. Hydro forced outage rates (not currently modeled)
    g. Hydro plant H/K factors
    h. Spreadsheet demonstrating how the hydro energy final output from the PNCA study is adjusted to arrive at the monthly energy output on the PwrAEOut sheet
11. Electric and Gas Contract Inputs
    a. Copy of contract for each long-term (5-year or greater term) or non-standard power contract modeled in Monet.

        For some contracts, this may consist of a term sheet rather than a full contract, depending on what was deemed reasonably necessary by the power modelers to model the contract in Monet.
    b. BookRunner extracts for the test year of:

        Electric Physical Contracts
        Electric Financial Contracts
        Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

c. Copy of each firm gas transportation or storage contract modeled in Monet
d. List of the PURPA QF contracts modeled in Monet
e. List of the long-term (5-year or greater term) or non-standard contracts modeled in MONET that were not included in PGE's most recent GRC or AUT.
f. Gas transportation input spreadsheet or its successor/equivalent
g. Website snapshots input to the gas transportation spreadsheet
h. Other Supporting Documents and Work Papers for contracts modeled in Monet, including any items showing on the Monet Cost and/or Energy Output reports not covered above. Could include structured contracts, option contracts, etc.
i. Coal contracts: Covered above under Thermal Plant Inputs
j. Amortizations of regulatory assets or liabilities modeled in the Contracts section of Monet

12. Wheeling Inputs
    a. Supporting Documents and Work Papers for all wheeling items modeled in Monet
13. Wind Power Inputs. Includes but not limited to:
    a. Monthly energy
    b. Hourly energy
    c. Maintenance
    d. Forced outage rates
    e. Integration costs, royalties, other costs and elements modeled
14. Modeling Enhancements and New Item Inputs
    a. Supporting Documents and Work Papers for all modeling enhancements and new items modeled in Monet.
    b. Includes modeling or logic changes, changes to the methodology used to compute data inputs or other type of enhancement to the Monet model.
    c. Modeling revisions, refinements, clean-ups etc. that do not affect NVPC under any conditions will not be considered to be modeling enhancements.
15. Miscellaneous
    a. Line Item Adjustments to Monet such as OPUC orders, settlement stipulations, others
    b. Identification of all transactions modeled in Monet that do not produce energy
    c. Items in Monet not covered elsewhere above
    d. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

<u>Historical Operating Data</u>

16. Hourly extract of data from PGE's Power Scheduling and Accounting System showing actual hourly energy values for the most recent Four-Year Calendar Period of the following:
    a. Generation from each coal, gas, hydro and wind generating plant modeled in Monet. Note that Colstrip Units 3 and 4 generation is aggregated in PGE's system, and the Mid-C contract generation is similarly aggregated.
    b. Long-term (>5 years) electric contract purchases, sales and exchanges modeled in Monet.
17. Table showing the actual monthly generation of each PGE coal, gas, hydro and wind generating plant modeled in MONET, from the period 1998 through the last calendar year.
18. Monthly compilations of actual NVPC produced by PGE for the most recent calendar year.

## Update Filings

19. Monet model for the final step
20. Hourly Diagnostic Reports for the final step
21. Step Log showing effect on NVPC of each update step since the last filing
22. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
23. For each Monet update step:
    a. Text description of update, including identification and location of input changes within Monet.
    b. Excel file containing Monet standard output reports (PwrCsOut, PwrAEOut, PwrEnOut) and PC Input sheets.
    c. Supporting Documents and Work Papers for the update step
24. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

# UE XXX

# Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

*Robert Macfarlane*
*Teresa Tang*

April 1, 2021

# Table of Contents

# I. Introduction and Summary

**Q. Please state your names and positions.**

A. My name is Robert Macfarlane. I am Manager of Pricing and Tariff for Portland General Electric Company (PGE).

My name is Teresa Tang. I am a Regulatory Consultant in the Pricing and Tariff Department. Our qualifications are included at the end of this testimony.

**Q. What is the purpose of your testimony?**

A. My testimony describes the following:

- The estimated base rate impacts from this filing anticipated to occur on January 1, 2022.
- The calculation of Schedule 125 prices.
- The calculation of the changes in the applicable System usage and Distribution prices for individual rate schedules related to Special Conditions 1 and 2 of Schedule 129 and Schedule 139, Long-Term Transition Adjustments.
- Proposed revision to Schedule 125 tariff.

PGE will file the final Schedule 125 tariff prices that will incorporate the final updates to Net Variable Power Costs (NVPC) in November 2021. The changes in the other applicable base rate schedules will also be filed at that time.

**Q. What are the base rate impacts of the proposed $38.9 million increase in Schedule 125 prices, inclusive of changes in system usage charges?**

A. Table 1, below, summarizes the estimated 2022 cost of service (COS) base rate impacts for selected rate schedules. These estimates are preliminary and subject to changes in market electric and gas prices and forecasted loads, among other items.

**Table 1**
**Estimated Base Rate Impacts**

| Schedule | Rate Impact |
|---|---|
| Sch 7 Residential | 2.1 % |
| Sch 32 Small Non-residential 30 kW or less | 2.0 % |
| Sch 83 Non-residential 31-200 kW | 2.5 % |
| Sch 85 Secondary 201-4,000 kW | 2.9 % |
| Sch 85 Primary 201-4,000 kW | 3.0 % |
| Sch 89 Primary Over 4,000 kW | 3.4 % |
| Sch 89 Subtransmission Over 4,000 kW | 2.9 % |
| Schedule 90 Over 100 MWa | 3.6 % |
| COS Overall | 2.4 % |

## II. Calculation of Schedule 125 Prices

**Q. Please describe how you calculated the Schedule 125 amount.**

A. We determine the Schedule 125 amount by comparing the projected 2022 NVPC to the amount of NVPC that is recovered through the NVPC portion of current energy prices (NVPC prices), multiplied by the 2022 load forecast by schedule (NVPC revenues). The difference between 2022 NVPC and NVPC revenues constitutes the change in NVPC. This amount, either positive or negative, is multiplied by 1.0320 to account for revenue sensitive costs such as uncollectibles and franchise fees. Page 1 of PGE Exhibit 201 provides a summary of the Schedule 125 amount of $38.9 million and how it is spread to the respective schedules. Also included on page 1 are the proposed Schedule 125 prices.

**Q. Please provide a more detailed description of how you calculate the NVPC revenues.**

A. Page 1 of PGE Exhibit 202 demonstrates the calculation. We multiply the NVPC prices determined in UE 335 by the respective projected energy billing determinants to calculate the amount of NVPC projected to be recovered in 2022. For 2022, we project NVPC revenues of $511.8 million. This amount is carried over to Page 1 of PGE Exhibit 201 in order to calculate the Schedule 125 amount.

**Q. Please describe how you allocate the Schedule 125 amount to each rate schedule and how you calculate the Schedule 125 price.**

A. We allocate and price the Schedule 125 amount consistent with Special Condition 1 of Schedule 125 which states:

> Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

**Q. Where is the calculation of the basis of the Schedule 125 allocations, the 2022 Base Generation Revenues?**

A. We present this calculation, which is simply the 2022 projected energy billing determinants times the tariff energy prices, on page 1 of PGE Exhibit 202.

## III. Calculation of System Usage and Distribution Prices

**Q. Do you propose to change the System Usage and Distribution Prices for the various rate schedules**?

A. Yes. We propose this because it is consistent with Special Conditions 1 and 2 of Schedule 129 and Schedule 139. Schedule 139 is the new large load Cost-of-Service Opt-Out service for large nonresidential customer, which was established in November 2019. These Special Conditions specify that PGE annually true-up the collections or credits related to prospective transition adjustment payments made by long-term direct access (LTDA) customers and new load long-term direct access (NLDA) customers at the time that PGE files final rates for Schedule 125.

**Q. How do you allocate the Schedule 129 and Schedule 139 Transition Adjustment payments from LTDA and NLDA customers to the rate schedules?**

A. Consistent with Special Condition 1 of Schedule 129 and Schedule 139, we allocate the long term transition adjustment payments received from LTDA and NLDA customers to all customers on the basis of equal cents per kWh. We then compare these allocations of 2022 long term transition adjustment payments to the amount that is currently embedded in the System Usage and Distribution prices determined in PGE's most recent AUT filing, as of November 2020. For Schedules 85, 89, 90 and their direct access equivalent schedules, the System Usage Charges are expected to increase by 0.46 mills/kWh. For other schedules, the System Usage or Distribution Charges are also expected to increase by 0.46 mills/kWh. PGE Exhibit 203 provides detail regarding the price change calculations.

**Q. In addition to truing-up the Schedule 129 and Schedule 139 Transition Adjustment payments, what other factors may cause changes to the System Usage or Distribution Charges?**

A. Should additional enrollment in LTDA and NLDA occur in in the September 2021 LTDA enrollment window for service commencing in 2022, PGE will allocate the additional long term Transition Adjustments from that enrollment window consistent with Special Condition 1, and, additionally, allocate the incremental changes in fixed generation revenues consistent with Special Conditions 2 and 3.

**Q. Does a potential change in the Distribution Charges for the Outdoor Lighting Schedules 15, 91, 95, 491, 495, 515, 591, and 595 mean that the Compliance Filing to this docket may include changes to the numerous fixture prices included in these schedules?**

A. Yes. The true-up of long term Transition Adjustments may require changes in the fixture prices for those rate schedules with an energy price included as part of the fixture price.

## IV. Non-Price Modifications to Schedule 125

**Q. Do you propose any changes other than price to Schedule 125?**

A. Yes. We propose three changes to the Annual Updates section of Schedule 125.

**Q. What change do you propose to the Annual Updates section of Schedule 125?**

A. First, we propose to modify the language regarding cost associated with wind integration to, "costs associated with integrating variable energy resources." PGE's 2022 initial NVPC forecast includes the cost associated with integrating both wind and solar resources and could potentially add other types of variable energy resources in the future. This language change not only allows for, in addition to wind, the recovery of solar integration costs, but recognizes that the integration of variable energy resources is not limited to just wind and solar resources. This change in language will reflect the realities of PGE's system more holistically.

Second, the forward market prices update is expanded to incorporate changes in oil forward prices and foreign exchange rates. PGE has routinely included these updates in its yearly AUT filings, and this change simply aligns the updates outlined in Schedule 125 with Commission Order No. 08-505, establishing the scope of the AUT.

Third, we propose to explicitly list what updates are included in the November 6th update and November 15th update, and we included two new items to the November 15th update.

**Q. What are the two items PGE is proposing to add to the final NVPC update?**

A. PGE is proposing to add language to reflect the following updates:

1. Update to Qualifying Facilities Commercial Online Dates (CODs) per Commission Order No. 18-464; and
2. Update to the price applied to the energy generation at the Priest Rapids and Wanapum hydro facilities, as provided in the power contract between PGE and

Grant County. The price applied to this contract for each future test year (i.e., 2022 for this AUT) is based on an auction that takes place the prior year at the beginning of November. For example, the contract price for 2022 will be established at the auction occurring in the beginning of November 2021. Often, this auction timing is too late for PGE to update the contract price within the first November MONET update. By allowing for this annual update to occur in the final MONET update, what customers pay for this energy will more accurately reflect the actual price PGE will pay for energy delivered in the test year. For more detail regarding the power contract with Grant County please refer to the MFRs, Volume 4 – Hydro / Cost / Priest Rapids Renewal.

**Q. Does this conclude your testimony?**

A. Yes.

# V. Qualification

**Q. Mr. Macfarlane, please state your educational background and qualifications.**

A. I received a Bachelor of Arts business degree from Portland State University with a focus in Finance. I have worked in the Rates and Regulatory Affairs Department since joining PGE in 2008. My duties at PGE have included pricing, revenue requirement, Public Utility Regulatory Policies Act avoided costs, and regulatory issues. From 2004 to 2008, I was a consultant with Bates Private Capital in Lake Oswego, OR, where I developed, prepared, and reviewed financial analyses used in securities litigation.

**Q. Mr. Tang, please state your educational background and qualifications.**

A. I received a Master of Art degree in Economics from University of California, Davis and a Master of Science degree in Statistics from Portland State University. I joined PGE's Rates and Regulatory Affairs department in 2020. In my current role, I am responsible for the preparation of rate design and pricing analyses. Prior to joining PGE, I was a regulatory consultant at PacifiCorp since 2008, working in various areas, including regulation, net power cost, production cost modeling, and load forecasts for six states in PacifiCorp's service territory.

## List of Exhibits

| Exhibit | Description |
|---|---|
| 201 | Calculation of Schedule 125 Prices |
| 202 | Calculation of Adjusted Fixed and Variable Generation Prices |
| 203 | Calculation of System Usage and Distribution Prices |
| 204 | Schedule 125 Sheet 125-1 Redline |

**PORTLAND GENERAL ELECTRIC**
**Calculation of Schedule 125 Prices**

| Schedules | 2022 Calendar COS Energy MWh | 2022 Base Generation Revenues | Generation Allocation | 2022 Base NVPC Revenues | Sch 125 Allocation | 2022 NVPC Revenues | 2022 Sch 125 Price mills/kWh | 2022 Sch 125 Revenues | Cycle MWh | Cycle Revenues | Sch 125 Revenues at Current Price | Sch 125 Revenues at Updated Price | Sch 125 Incremental Revenue Change |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Schedule 7** | 7,560,991 | $486,708 | 45.10% | $170,576 | $61,773 | $232,349 | 8.17 | $61,773 | 7,555,010 | $61,724 | 44,196,811 | 61,724,435 | $17,527,624 |
| **Schedule 15** | 14,480 | $709 | 0.07% | $248 | $90 | $338 | 6.22 | $90 | 14,480 | $90 | 64,291 | 90,066 | $25,774 |
| **Schedule 32** | 1,576,916 | $92,123 | 8.54% | $32,201 | $11,692 | $43,893 | 7.41 | $11,685 | 1,576,157 | $11,679 | 8,353,631 | 11,679,321 | $3,325,691 |
| **Schedule 38** | 31,529 | $1,702 | 0.16% | $594 | $216 | $810 | 6.85 | $216 | 31,528 | $216 | 154,487 | 215,967 | $61,480 |
| **Schedule 47** | 20,699 | $1,468 | 0.14% | $514 | $186 | $700 | 9.00 | $186 | 20,075 | $181 | 129,283 | 180,675 | $51,392 |
| **Schedule 49** | 61,728 | $4,363 | 0.40% | $1,527 | $554 | $2,080 | 8.97 | $554 | 61,430 | $551 | 393,768 | 551,030 | $157,262 |
| **Schedule 83** | 2,801,114 | $163,127 | 15.12% | $57,115 | $20,704 | $77,819 | 7.39 | $20,700 | 2,800,127 | $20,693 | 14,784,669 | 20,692,937 | $5,908,267 |
| **Schedule 85-S** | 2,136,010 | $121,153 | 11.23% | $41,930 | $15,377 | $57,306 | 7.20 | $15,379 | 2,134,357 | $15,367 | 10,991,940 | 15,367,373 | $4,375,433 |
| **Schedule 85-P** | 594,188 | $32,874 | 3.05% | $11,462 | $4,172 | $15,634 | 7.02 | $4,171 | 612,588 | $4,300 | 3,075,190 | 4,300,365 | $1,225,175 |
| **Schedule 89-S** | 0 | $0 | 0.00% | $0 | $0 | $0 | 6.67 | $0 | 0 | $0 | 0 | 0 | $0 |
| **Schedule 89-P** | 561,528 | $29,000 | 2.69% | $10,096 | $3,681 | $13,777 | 6.55 | $3,678 | 562,911 | $3,687 | 2,640,052 | 3,687,066 | $1,047,014 |
| **Schedule 89-T** | 53,685 | $2,791 | 0.26% | $952 | $354 | $1,307 | 6.60 | $354 | 53,697 | $354 | 251,302 | 354,401 | $103,098 |
| **Schedule 90** | 2,853,201 | $140,944 | 13.06% | $51,072 | $17,888 | $68,961 | 6.27 | $17,890 | 2,824,250 | $17,708 | 12,652,638 | 17,708,045 | $5,055,407 |
| **Schedule 91** | 41,836 | $2,049 | 0.19% | $717 | $260 | $977 | 6.22 | $260 | 41,836 | $260 | 185,752 | 260,220 | $74,468 |
| **Schedule 92** | 2,576 | $132 | 0.01% | $46 | $17 | $63 | 6.48 | $17 | 2,576 | $17 | 11,953 | 16,692 | $4,740 |
| **TOTAL** | 18,310,481 | $1,079,143 | 100.00% | $379,049 | $136,964 | $516,013 | | $136,954 | 18,291,022 | $136,829 | 97,885,768 | $136,828,593 | **$38,942,825** |

| | |
|---|---|
| 2022 NVPC ($000) | $511,766 |
| 2022 NVPC Revenues at Current Prices ($000) | $379,049 |
| Change in NVPC | $132,717 |
| Revenue Sensitive Adj. 3.2% | $4,247 |
| Sch 125 Revenue Requirement | $136,964 |

**PORTLAND GENERAL ELECTRIC**
**Calculation of Generation and NVPC Revenues**

| Schedule | 2022 Calendar MWh | UE 335 Energy Price | 2022 Base Energy Revenues | NVPC Price | 2022 NVPC Revenues | 2022 Cycle MWh | 2022 Cycle to Calendar Ratio |
|---|---|---|---|---|---|---|---|
| Sch 7 | | | | | | | |
| Block 1 | 6,428,992 | 63.29 | $406,891 | 22.56 | $145,038 | 6,423,906 | 0.999209 |
| Block 2 | 1,131,999 | 70.51 | $79,817 | 22.56 | $25,538 | 1,131,104 | 0.999209 |
| Sch 15 | 14,480 | 48.98 | $709 | 17.13 | $248 | 14,480 | 1.000000 |
| Sch 32 | 1,576,916 | 58.42 | $92,123 | 20.42 | $32,201 | 1,576,157 | 0.999518 |
| Sch 38 | | | | | | | |
| On-peak | 17,390 | 60.70 | $1,056 | 18.84 | $328 | 17,389 | 0.999958 |
| Off-peak | 14,140 | 45.70 | $646 | 18.84 | $266 | 14,139 | 0.999958 |
| Sch 47 | 20,699 | 70.94 | $1,468 | 24.82 | $514 | 20,075 | 0.969853 |
| Sch 49 | 61,728 | 70.68 | $4,363 | 24.73 | $1,527 | 61,430 | 0.995175 |
| Sch 83 | | | | | | | |
| On-peak | 1,846,208 | 63.35 | $116,957 | 20.39 | $37,644 | 1,845,558 | 0.999648 |
| Off-peak | 954,906 | 48.35 | $46,170 | 20.39 | $19,471 | 954,569 | 0.999648 |
| Sch 85-S | | | | | | | |
| On-peak | 1,396,834 | 61.91 | $86,478 | 19.63 | $27,420 | 1,395,753 | 0.999227 |
| Off-peak | 739,176 | 46.91 | $34,675 | 19.63 | $14,510 | 738,604 | 0.999227 |
| Sch 85-P | | | | | | | |
| On-peak | 374,961 | 60.86 | $22,820 | 19.29 | $7,233 | 386,572 | 1.030966 |
| Off-peak | 219,227 | 45.86 | $10,054 | 19.29 | $4,229 | 226,015 | 1.030966 |
| Sch 89-S | | | | | | | |
| On-peak | 0 | 58.69 | $0 | 18.32 | $0 | 0 | 1.000000 |
| Off-peak | 0 | 43.69 | $0 | 18.32 | $0 | 0 | 1.000000 |
| Sch 89-P | | | | | | | |
| On-peak | 333,759 | 57.73 | $19,268 | 17.98 | $6,001 | 334,580 | 1.002462 |
| Off-peak | 227,770 | 42.73 | $9,733 | 17.98 | $4,095 | 228,330 | 1.002462 |
| Sch 89-T | | | | | | | |
| On-peak | 35,646 | 57.02 | $2,033 | 17.74 | $632 | 35,654 | 1.000225 |
| Off-peak | 18,039 | 42.02 | $758 | 17.74 | $320 | 18,043 | 1.000225 |
| Sch 90 | | | | | | | |
| On-peak | 1,641,267 | 55.77 | $91,533 | 17.90 | $29,379 | 1,624,613 | 0.989853 |
| Off-peak | 1,211,934 | 40.77 | $49,411 | 17.90 | $21,694 | 1,199,636 | 0.989853 |
| Sch 91/95 | 41,836 | 48.98 | $2,049 | 17.13 | $717 | 41,836 | 1.000000 |
| Sch 92 | 2,576 | 51.09 | $132 | 17.88 | $46 | 2,576 | 1.000000 |
| Totals | 18,310,481 | | $1,079,143 | | $379,049 | 18,291,022 | 0.99894 |

**UE 335 Fixed and NVPC Prices**

| Schedule | 2019 Calendar COS Energy MWh | Generation Allocation | Generation Fixed | NVPC Revenues | Fixed mills/kWh | Fixed Revenues | NVPC mills/kWh |
|---|---|---|---|---|---|---|---|
| Sch 7 | 7,568,915 | 47.23% | $316,561,014 | $170,751,844 | 41.82 | $316,532,034 | 22.56 |
| Sch 15 | 15,774 | 0.07% | $501,088 | $270,285 | 31.77 | $501,140 | 17.13 |
| Sch 32 | 1,631,912 | 9.22% | $61,791,153 | $33,329,920 | 37.86 | $61,784,176 | 20.42 |
| Sch 38 | 31,497 | 0.16% | $1,099,956 | $593,312 | 34.92 | $1,099,881 | 18.84 |
| Sch 47 | 21,670 | 0.15% | $997,052 | $537,806 | 46.01 | $997,042 | 24.82 |
| Sch 49 | 64,510 | 0.44% | $2,957,360 | $1,595,189 | 45.84 | $2,957,138 | 24.73 |
| Sch 83 | 2,887,308 | 16.28% | $109,132,384 | $58,865,606 | 37.80 | $109,140,257 | 20.39 |
| Sch 85-S | 2,115,981 | 11.49% | $77,016,237 | $41,542,274 | 36.40 | $77,021,717 | 19.63 |
| Sch 85-P | 598,670 | 3.19% | $21,404,592 | $11,545,558 | 35.75 | $21,402,437 | 19.29 |
| Sch 89-S | 0 | 0.00% | $0 | $0 | 33.97 | $0 | 18.32 |
| Sch 89-P | 392,599 | 1.95% | $13,088,821 | $7,060,062 | 33.34 | $13,089,236 | 17.98 |
| Sch 89-T | 62,359 | 0.31% | $2,051,246 | $1,106,434 | 32.89 | $2,050,980 | 17.74 |
| Sch 90-P | 1,867,228 | 9.24% | $61,954,179 | $33,417,856 | 33.18 | $61,954,614 | 17.90 |
| Sch 91/95 | 50,583 | 0.24% | $1,606,866 | $866,738 | 31.77 | $1,607,022 | 17.13 |
| Sch 92 | 2,496 | 0.01% | $82,715 | $44,616 | 33.14 | $82,717 | 17.88 |
| Totals | 17,311,501 | 100.00% | $670,244,663 | $361,527,500 | 38.72 | $670,220,391 | 20.88 |

| Category | Rev. Req. | Percent |
|---|---|---|
| Fixed | $670,245 | 64.96% |
| Variable | $361,528 | 35.04% |
| Total | $1,031,772 | 100.00% |

**PORTLAND GENERAL ELECTRIC**
**CALCULATION OF SYSTEM USAGE AND DISTRIBUTION PRICES**
**Allocation of Schedule 129/139 Transition Adjustment**
**2022**

**ALLOCATION OF TRANSITION ADJUSTMENT**

| Schedules | Cycle Energy | Percent | Allocations ($000) | mills/kWh |
|---|---|---|---|---|
| Schedule 7 | 7,555,010 | 36.9% | ($4,243) | (0.56) |
| Schedule 15 | 14,480 | 0.1% | ($8) | (0.56) |
| Schedule 32 | 1,576,157 | 7.7% | ($885) | (0.56) |
| Schedule 38 | 31,528 | 0.2% | ($18) | (0.56) |
| Schedule 47 | 20,075 | 0.1% | ($11) | (0.56) |
| Schedule 49 | 61,430 | 0.3% | ($34) | (0.56) |
| Schedule 83 | 2,800,127 | 13.7% | ($1,573) | (0.56) |
| Schedule 85-S | 2,652,837 | 12.9% | ($1,490) | (0.56) |
| Schedule 85-P | 986,063 | 4.8% | ($554) | (0.56) |
| Schedule 89-S | 13,878 | 0.1% | ($8) | (0.56) |
| Schedule 89-P | 1,619,259 | 7.9% | ($909) | (0.56) |
| Schedule 89-T | 297,536 | 1.5% | ($167) | (0.56) |
| Schedule 90-P | 2,824,250 | 13.8% | ($1,586) | (0.56) |
| Schedules 91/95 | 41,836 | 0.2% | ($23) | (0.56) |
| Schedule 92 | 2,576 | 0.0% | ($1) | (0.56) |
| | | | | |
| TOTAL | 20,497,042 | 100.00% | ($11,511) | (0.56) |
| | | | | |
| | | TARGET | ($11,511) | |

**Change in Schedule 129/139 Transfer Payment Amount 2022**

| Schedules | Current mills/kWh | 2022 mills/kWh | Change mills/kWh | Tariff Category |
|---|---|---|---|---|
| Schedule 7 | (1.02) | (0.56) | 0.46 | Distribution |
| Schedule 15 | (1.02) | (0.56) | 0.46 | Distribution |
| Schedule 32 | (1.02) | (0.56) | 0.46 | Distribution |
| Schedule 38 | (1.02) | (0.56) | 0.46 | Distribution |
| Schedule 47 | (1.02) | (0.56) | 0.46 | Distribution |
| Schedule 49 | (1.02) | (0.56) | 0.46 | Distribution |
| Schedule 83 | (1.02) | (0.56) | 0.46 | System Usage |
| Schedule 85-S | (1.02) | (0.56) | 0.46 | System Usage |
| Schedule 85-P | (1.02) | (0.56) | 0.46 | System Usage |
| Schedule 89-S | (1.02) | (0.56) | 0.46 | System Usage |
| Schedule 89-P | (1.02) | (0.56) | 0.46 | System Usage |
| Schedule 89-T | (1.02) | (0.56) | 0.46 | System Usage |
| Schedule 90-P | (1.02) | (0.56) | 0.46 | System Usage |
| Schedules 91/95 | (1.02) | (0.56) | 0.46 | Distribution |
| Schedule 92 | (1.02) | (0.56) | 0.46 | Distribution |
| | | | | |
| TOTAL | | | | |

**Total Change in Distribution/System Usage Charge 2022**

| Schedules | Sys. Usage Current mills/kWh | Sch 129/139 Change mills/kWh | 2022 Sys. Usage mills/kWh | Category |
|---|---|---|---|---|
| **Schedule 7** | 2.13 | 0.46 | 2.59 | Distribution |
| **Schedule 15** | 10.39 | 0.46 | 10.85 | Distribution |
| **Schedule 32** | 1.82 | 0.46 | 2.28 | Distribution |
| **Schedule 38** | 2.29 | 0.46 | 2.75 | Distribution |
| **Schedule 47** | 4.10 | 0.46 | 4.56 | Distribution |
| **Schedule 49** | 2.66 | 0.46 | 3.12 | Distribution |
| **Schedule 83** | 6.94 | 0.46 | 7.40 | System Usage |
| **Schedule 85-S** | 0.92 | 0.46 | 1.38 | System Usage |
| **Schedule 85-P** | 0.88 | 0.46 | 1.34 | System Usage |
| **Schedule 89-S** | 0.97 | 0.46 | 1.43 | System Usage |
| **Schedule 89-P** | 0.94 | 0.46 | 1.40 | System Usage |
| **Schedule 89-T** | 0.92 | 0.46 | 1.38 | System Usage |
| **Schedule 90-P** | 0.49 | 0.46 | 0.95 | System Usage |
| **Schedules 91/95** | 2.63 | 0.46 | 3.09 | Distribution |
| **Schedule 92** | 1.05 | 0.46 | 1.51 | Distribution |
| **Schedule 515** | 9.19 | 0.46 | 9.65 | Distribution |
| **Schedule 532** | 0.37 | 0.46 | 0.83 | Distribution |
| **Schedule 538** | 0.96 | 0.46 | 1.42 | Distribution |
| **Schedule 549** | 0.89 | 0.46 | 1.35 | Distribution |
| **Schedule 583** | 5.49 | 0.46 | 5.95 | System Usage |
| **Schedule 485/585-S** | (0.33) | 0.46 | 0.13 | System Usage |
| **Schedule 485/585-P** | (0.34) | 0.46 | 0.12 | System Usage |
| **Schedule 489/589-S** | (0.17) | 0.46 | 0.29 | System Usage |
| **Schedule 489/589/689-P** | (0.20) | 0.46 | 0.26 | System Usage |
| **Schedule 489/589-T** | (0.20) | 0.46 | 0.26 | System Usage |
| **Schedule 490/590** | (0.72) | 0.46 | (0.26) | System Usage |
| **Schedule 491/495/591/595** | 1.43 | 0.46 | 1.89 | Distribution |
| **Schedule 492/592** | (0.21) | 0.46 | 0.25 | Distribution |

## SCHEDULE 125
## ANNUAL POWER COST UPDATE

### PURPOSE

The purpose of this adjustment schedule is to define procedures for annual rate revisions due to changes in the Company's projected Net Variable Power Costs (the Annual Power Cost Update). This schedule is an "automatic adjustment clause" as defined in ORS 757.210(1), and is subject to review by the Commission at least once every two years.

### APPLICABLE

To all Cost-of-Service bills for Electricity Service served under the following rate schedules 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 90, 91, 92, and 95. Customers served under the daily price option contained in schedules 32, 38, 75, 81, 83, 85, 89, 90, 91, and 95 are exempt from Schedule 125.

### NET VARIABLE POWER COSTS

Net Variable Power Costs (NVPC) are the power costs for energy generated and purchased. NVPC are the net cost of fuel and emission control chemicals, fuel and emission control chemical transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load.

### RATES

This adjustment rate is subject to increases or decreases, which may be made without prior hearing, to reflect increases or decreases, or both, in NVPC.

### ANNUAL UPDATES

The following updates will be made in each of the Annual Power Cost Update filings:

- Forced Outage Rates based on a four-year rolling average.
- Projected planned plant outages.
- Wind energy forecast based on a five-year rolling average.
- Costs associated with variable energy resources~~wind~~ integration.
- Forward market prices for ~~both~~ gas~~ and~~, electricity, oil, and foreign exchange rates.~~-~~
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Emission control chemical costs.
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes.
- Changes in hedges, options, and other financial instruments used to serve retail load.
- Transportation contracts and other fixed transportation costs.
- Reciprocating engine lubrication oil costs.
- Projections of State and Federal Production Tax Credits. **(N)**
- No other changes or updates will be made in the annual filings under this schedule.

**SCHEDULE 125 (Continued)**

**CHANGES IN NET VARIABLE POWER COSTS**

Changes in NVPC for purposes of rate determination under this schedule are the projected NVPC as determined in the Annual Power Cost Update less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case, adjusted for a revenue sensitive cost factor of 1.0320.

**FILING AND EFFECTIVE DATE**

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

~~On November 6, 2020, for one-time only and due to extraordinary wildfire events in the state of Oregon, the Company will file updated estimates with final planned maintenance outages for the following hydro facilities: Faraday, Oak Grove, Harriet Lake, Timothy Lake, and Stone Creek.~~ **(N)** | **(N)**

On or before November 6 of each calendar year, the Company will file updated estimates with the final planned maintenance outages and load forecast from the October 1st filing, load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, updated projections of gas and electric prices, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2)~~ load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3)~~ new market power and fuel contracts entered into since the previous updates,~~ and~~ 3~~4~~) the final planned maintenance outages and load forecast from the October 1st filing, 4) final update to Qualifying Facilities~~F~~ online dates, and 5) final price for the energy generation at the Priest Rapids and Wanapum hydro facilities, as provided in the power contract between PGE and Grant County.~~.~~

**RATE ADJUSTMENT**

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.