Portland General Electric Company
121 SW Salmon Street • 1WTC0306 • Portland, OR 97204
portlandgeneral.com

April 1, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

RE: UE_XXX In the Matter of Portland General Electric Company's 2021 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**:
  - Kit Seulean, Cathy Kim, Greg Batzler (PGE / 100) and Exhibits 101-102
  - Andrew Speer (PGE / 200) and Exhibits 201-204
- **Motion for Approval of Protective Order (with proposed Protective Order)**

Non-confidential work papers have been submitted to puc.workpapers@state.or.us.

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

In tandem with Oregon's decarbonization policy direction, PGE is focusing its efforts on decarbonizing, electrifying its service territory, and performing operationally for its customer and shareholders. PGE's annual power cost filing reflects PGE's continuing efforts to decarbonize its generation and provide affordable, reliable power to its customers through the optimization of its power supply resources.

PGE's initial forecast of 2021 net variable power costs is $436.2 million. PGE's preliminary estimate of base rate impacts is an increase effective January 1, 2020 of about 2.4%.

Sincerely,

/s/ *Jaki Ferchland*
Jaki Ferchland
Manager, Revenue Requirement

JF/np
Enclosure
cc: UE 335 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PORTLAND GENERAL ELECTRIC COMPANY's 2021 ANNUAL POWER COST UPDATE TARIFF OF DIRECT TESTIMONY** to be served by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket No. UE 335.

DATED at Portland, Oregon, this 1st day of April, 2020.

/s/ *Jaki Ferchland*
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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX
Annual Update Tariff Filing
For Prices Effective January 1, 2021

PORTLAND GENERAL ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBITS

April 1, 2020

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX

Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Kit Seulean
Cathy Kim
Greg Batzler

April 1, 2020

Table of Contents

I. Introduction

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

A. My name is Kit Seulean. My position at PGE is Manager, Power Cost Forecasting and Analysis.

My name is Cathy Kim. My position at PGE is Senior Director, Energy Supply.

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 Annual Update Tariff (AUT) forecast of PGE's 2021 Net Variable Power Costs (NVPC). We discuss several of the updates included in this initial forecast for 2021, as well as provide an update on PGE's efforts to comply with the Public Utility Commission of Oregon (Commission or OPUC) directions in Order No. 19-329 (Docket No. UE 359). We also compare our initial forecast with PGE's final 2020 NVPC forecast and explain why the per-unit expected NVPC have increased by approximately $2.19 per MWh.

Q. What is your 2021 AUT forecast?

A. Our initial 2021 NVPC forecast is $436.2 million, based on contracts and forward curves as of February 28, 2020. This initial 2021 NVPC forecast represents an increase of $42.7 million relative to our final 2020 NVPC forecast.

Q. What are the primary factors that explain the increase in NVPC forecast for 2021 versus the NVPC forecast for 2020 in Docket No. UE 359?

A. The primary factors contributing to the increase in NVPC include: 1) an increase in power costs due to Boardman ending operations in 2020, which reduces the market sales forecasted for 2021 compared to the forecast for 2020; 2) an increase in costs related to market energy and capacity purchases, largely driven by contracts entered into as a result of bilateral negotiations to address the 2016 Integrated Resource Plan (IRP) capacity need; 3) an increase in transmission costs; and 4) a decrease in expected market sales due to a 14 MWa projected load increase in 2021.

Q. Does PGE expect other factors to impact the 2021 NVPC forecast?

A. Possibly. The current economic contraction due to the emerging COVID-19 pandemic could introduce uncertainty and potentially impact PGE's 2021 NVPC forecast. PGE will closely monitor power markets and electric load patterns and incorporate any necessary changes in subsequent power cost updates.

Q. Have you proposed a schedule in this docket for NVPC updates?

A. Yes. We propose the following schedule for the power cost updates:

- July - Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages;
- October - Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned hydro maintenance outages; and loads; and

- November - Two update filings: 1) update gas and electric forward curves; 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 and qualifying facilities (QF) online dates.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II: MONET Model;
- Section III: MONET Updates;
- Section IV: 2021 Load Forecast;
- Section V: Comparison with 2020 NVPC Forecast; and
- Section VI: Qualifications.

II. MONET Model

Q. How did PGE forecast its NVPC for 2021?

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. PGE 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 net variable power costs 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.

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 2020 AUT power cost forecast, we include certain variable chemical costs, lubricating oil costs, and we include forecasted production tax credits (PTC)s for eligible resources, predominantly wind. 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 minimum filing requirements (MFRs) provide more detailed information regarding inputs to MONET?

A. Yes. Commission Order No. 08-505 adopted a list of MFRs for PGE in AUT filings and general rate case filings. These MFRs provide detailed work papers supporting the inputs used to develop our initial forecast of 2021 NVPC. PGE Exhibit 101 contains the list of required documents under Order No. 08-505.

III. MONET 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.

Q. Which of these updates do you include in this initial filing?

A. We include all the updates listed above and address significant items below.

[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.

A. Western Energy Imbalance Market (Western EIM or EIM) Benefits

Q. Please describe the Western EIM.

A. The Western EIM is a voluntary, balancing energy market operated by the California Independent System Operator (CAISO). Using software to optimize generator unit commitment and dispatch within and between Balancing Authority Areas (BAAs), the Western EIM identifies sub-hourly transactions (i.e., every 15 and 5 minutes) to serve real-time customer demand and facilitates transfer of excess energy generated in one area to another area where it is needed. This allows Western EIM participants to obtain the least-cost energy to serve their load and to effectively integrate output from variable renewable energy resources. The Western EIM's operations began November 1, 2014.[2]

Q. When did PGE begin participating in the Western EIM?

A. PGE began participation in the Western EIM on October 1, 2017. PGE concluded its second full calendar year of EIM participation in December 2019.

Q. How has participation in the EIM reduced PGE's actual NVPC?

A. The primary benefit is the savings associated with sub-hourly transactions (i.e., sub-hourly dispatch savings). Sub-hourly dispatch savings[3] result from PGE's ability to export and import in near real-time with other EIM participants to economically displace resources or respond to intra-hour imbalances. PGE imports power from the EIM to avoid production costs

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[2] In addition to PGE other active participants in the Western EIM are: Balancing Authority of Northern California (Phase 1), CAISO, PacifiCorp, NV Energy, Arizona Public Service, Puget Sound, Powerex, and Idaho Power Company. Planned participants are: Salt River Project (2020), Seattle City Light (2020), Los Angeles Department of Power & Water (2021), Public Service Company of New Mexico (2021), Northwestern Energy (2021), Avista (2021), Tucson Electric Power (2022), Tacoma Power (2022), and Bonneville Power Administration (2022).

[3] Sub-hourly dispatch savings include savings that can be attained through lower flexible ramping requirements in the EIM real-time market (i.e., flexible reserve savings). PGE's 'biddable' resources also predominantly hold PGE's flexible reserves. Therefore, the sub-hourly market instructions issued by CAISO in the EIM reflect the optimization of PGE's sub-hourly unit commitment and dispatch alongside other EIM entities, including the economic use of flexible reserves needed to meet EIM requirements.

on its more expensive generating resources when EIM prices are low. PGE exports power to the EIM, earning net revenues, when EIM prices are higher than PGE's marginal generation production costs.

Participants in the EIM can also be awarded greenhouse gas (GHG)-related revenue.[4] To the extent PGE receives GHG revenue, primarily associated with its hydro GHG offers, PGE can reduce NVPC.

Q. What is your expectation for the NVPC impacts from EIM?

A. We anticipate that EIM sub-hourly dispatch will reduce EIM-relevant production cost variables in the MONET forecast by approximately 1 to 2 percent, collectively. EIM-relevant production costs include 1) MONET's balancing purchases and 2) MONET's forecast of variable power costs from thermal resources.[5]

NVPC savings can also result from PGE receiving GHG awards in the EIM. NVPC savings from GHG awards in the EIM are incremental to PGE's sub-hourly dispatch savings and continue to be a substantial component of PGE's EIM benefit. We discuss GHG in detail later in our testimony.

Q. Please summarize PGE's 2021 EIM net benefit forecast.

A. PGE's 2021 EIM net benefit forecast is summarized in Table 1. Forecast EIM sub-hourly dispatch savings and GHG benefits are reduced by a grid management charge forecast.

[4] If CAISO determines generation within an EIM entity served CAISO load, CAISO must consider the cost of the greenhouse gas compliance obligation. GHG revenues result when the marginal cost of GHG compliance in EIM Entity BAAs for energy exported to CAISO is greater than zero.
[5] Thermal resources include Colstrip Unit 3, Colstrip Unit 4, Beaver Units 1-7, Port Westward 2, Coyote 1, Port Westward, and Carty.

Table 1
2021 Net Benefits Forecast Western EIM Participation

	NVPC Net Benefits	
1	Sub-Hourly Dispatch Savings	$4.0 million
2	GHG Benefit	$3.0 million
3	CAISO Grid Management Charges[6]	($1.0 million)
	Total	**$6.0 million**

<u>EIM Sub-Hourly Dispatch and Forecast for 2021</u>

Q. What is PGE's forecast for the reduction in NVPC from EIM sub-hourly dispatch in 2021?

A. In this initial filing, PGE's forecast is gross EIM sub-hourly dispatch savings of $4.0 million. This is approximately 2.1 percent of the relevant variable components in PGE's NVPC forecast, which is a reasonable expectation for the impact from EIM sub-hourly dispatch.

Q. Why do you believe approximately 1 to 2 percent is a reasonable expectation for the impact from EIM sub-hourly dispatch?

A. There are several reasons, which include:

- Third-party expertise[7] indicates to PGE that 1 to 2 percent of an organization's *<u>fuel budget</u>*[8] is a reasonable expectation for savings from EIM;
- In the past, PGE's production cost modeling in support of its initial EIM study[9] supported a similar conclusion; and

[6] 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. The grid management charges are a function of instructed imbalance energy amounts as well as absolute differences between metered energy and EIM base schedules.
[7] Power Cost, Inc., a provider of software solutions to energy supply and trading organizations, informs its clients to estimate EIM savings that will be approximately 1 to 2 percent of an organization's fuel budget.
[8] PGE's fuel budget represents the annual budget for thermal production cost plus market purchases.
[9] PGE's initial EIM study was performed by Energy + Environmental Economics (E3) and the result is available in the study titled, "PGE EIM Comparative Study: Economic Analysis Report." The study was submitted in Docket No. LC 56.

- PGE's measurement of actual EIM settlement results has been consistent with the expectation that sub-hourly dispatch can impact the "fuel budget" portion at a level consistent with the 1 to 2 percent metric.

Table 2 summarizes these findings. For example, PGE's forecast of NVPC benefit in 2018 and 2019 was approximately $5 million. The forecast was effectively two percent of the EIM-relevant production cost variables in the MONET forecast (i.e., 2.4 percent in 2018 and 2.1 percent in 2019). PGE's actual NVPC benefits ($4.7 million and $6.3 million) were consistent with the forecast value, as detailed in Table 2, below.

Table 2: EIM Sub-hourly Dispatch Savings
Percentage of Forecast NVPC Production Costs ($million)

	Initial E3 Study	**2018 NVPC Forecast**	**2019 NVPC Forecast**	**2021 AUT Forecast**
EIM-Relevant Cost Variables[1]	$318.5	$228.9	$233.5	$195.6
PGE Sub-Hour Dispatch Saving Forecast	$3.5	$5.6	$5.0	$4.0
% of EIM-Relevant Cost Variables	1.1%	2.4%	2.1%	2.1%
Actual EIM Settlement Measurment[2]	-	$4.7	$6.3	-

[1]Costs in NVPC forecast are the subset of MONET costs that are variable and capable of being influenced by PGE's activity in the EIM.
[2]Settlement actuals include fifteen-minute market, real-time dispatch, and uninstructed imbalance energy EIM purchases and sales measured against the resource-by-resource production costs reported in PGE settlement data.

Q. Please describe PGE's forecast for sub-hourly dispatch cost savings in its 2021 NVPC forecast.

A. PGE's forecast for sub-hourly dispatch cost savings is closely linked with the results 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 sub-hourly dispatch cost savings from the EIM, PGE treats MONET's purchases and sales as transactions made prior to the EIM operating hour. These transactions are then compared to an EIM price curve[10] to determine if MONET sales should be purchased back under EIM pricing, or if MONET purchases should be sold at EIM prices.

Q. Please provide an example.

A. Consider an hour when the MONET model sells energy (i.e., the forward price curve is higher than PGE's dispatch cost and PGE generation is greater than PGE load). MONET maximizes the NVPC savings by dispatching PGE's generation such that PGE marginal variable generation cost equals the forward price curve to its maximum MW, subject to model constraints. In its EIM methodology, PGE treats MONET's result as a schedule for the generation (i.e., dispatch is not yet certain) and PGE has an opportunity to attain additional NVPC benefit by having EIM displace PGE generation schedules with cheaper energy up to the EIM transaction limit imposed in the methodology.[11] In effect, the EIM purchase (and not PGE generation) becomes the energy transaction that supports a portion of the MONET sales.

Q. In your EIM purchase example, how is the EIM benefit determined?

A. It depends. If the methodology[12] displaces generation from a hydro resource, the benefit is the difference between the Mid-C sale price in MONET and the purchase price in EIM multiplied by the energy purchased in EIM. In other words, if the sale price in MONET was $30, PGE's EIM methodology will treat the $30 sale as the marginal cost that EIM can displace. While a hydro resource effectively has a zero-dollar production cost, the Mid-C

[10] The EIM price curve is the average of PGE's 2018 and 2019 fifteen-minute market prices, adjusted for price outliers. See PGE's MFRs for additional detail.
[11] In the methodology, PGE's EIM transaction volumes cannot exceed monthly average transactions in 2019 associated with hydro and thermal resource schedules.
[12] The methodology will prioritize displacement based on economics. That is, it will seek to displace hydro first (up to transaction limits) if doing so provides more benefit than displacing a thermal resource.

price (i.e., $30 in this example) is a reasonable cost for hydro because it can represent the opportunity cost of hydro for the upcoming operating hour.

If the methodology displaces generation from a thermal resource, the benefit is the difference between the production cost of the marginal thermal resource and the purchase price in EIM multiplied by the energy purchased in EIM. There is no opportunity cost concept applied to thermal resources in the methodology because thermal resources are already economically dispatched in MONET.

Q. In the EIM methodology, how is the hydro resource or thermal resource transaction limit identified?

A. The identification is based on actual CAISO instructions from 2019 data. PGE uses the fifteen-minute market and five-minute market changes from submitted resource schedules to establish monthly limits on market activity allowed during each MONET trading hour. The schedule limits are allocated into two categories: 1) a collective limit for hydro resources and 2) a collective limit for thermal resources.

Q. Please provide an example.

A. Table 3, below, illustrates the assignment. Table 3 lists a hypothetical set of monthly average changes from submitted generation schedules (i.e., PGE's planned operating point prior to EIM trading) where the trading activity was more heavily associated with submitted hydro schedules. In this example, the monthly limit for all MONET trading activity in the EIM will be 100 MW for purchases (i.e., decrease from base schedule) and sales (i.e., increase from base schedule). Within the limits, up to 75 MW of the trading can be measured based on the pricing for hydro and up to 25 MW of the trading can be measured based on the pricing for thermal.

Table 3: Hypothetical Monthly Average Changes from Submitted Generation Schedules

	Increase from Base Schedule	Decrease from Base Schedule
Hydro	75 MW	75 MW
Thermal	25 MW	25 MW
Total	100 MW	100 MW

Q. Will PGE update its forecast during the 2021 AUT 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 2021

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 $3.0 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 2021 NVPC forecast.

A. PGE's forecast for GHG benefit depends on 2019 actual results and the Intercontinental Exchange (ICE) forward price curve for the 2021 California Carbon Allowance. The forecast steps include:

1. Use GHG award price data ($/MWh) and 2019 GHG allowance prices ($/mTCO2[13]) to calculate a weighted implied emission factor (mTCO2/MWh).
2. Using the weighted implied emission factor, apply the ICE forward price curve for the 2021 California Carbon Allowance (ICE product code CAZ) to the implied emission factor to calculate a GHG Award Price ($/MWh).
3. Multiply the calculated GHG Award Price ($/MWh) by PGE's 2019 award quantities to create a GHG revenue forecast. This revenue is reduced by a forecast of GHG

[13] Metric tons of carbon dioxide.

compliance costs where applicable (i.e., thermal resources assumed to sell GHG in 2021).

Q. For sub-hourly dispatch savings, PGE determines a 1 percent to 2 percent impact on NVPC to be reasonable. Do you have a similar metric for GHG benefit in the EIM?

A. Not yet. The impact on NVPC from GHG award revenue in the EIM is more difficult to forecast for several reasons. First, in November 2018, the CAISO implemented policy change that reduces the quantity of GHG awards that an EIM participating resource receives.[14] Generally speaking, CAISO's policy change reduces the supply of GHG offers available from each resource, so its practical effect has been to reduce the supply of GHG offers from resources that are required to submit $0 offers for GHG sales and increases the clearing price for GHG awards. Second, in 2020 there will be new market participants, particularly Seattle City Light, that may elect to submit GHG offers in the EIM. If Seattle City Light submits GHG offers in its EIM bidding, CAISO rules will require the offers to be $0, and it is possible that the new $0 based supply could reduce the clearing price for GHG awards.

Q. Will PGE update its GHG benefit forecast during the 2021 AUT proceeding?

A. Yes. First, PGE plans to update the ICE forward curve consistent with other forward curve updates in the AUT proceeding. Second, PGE will monitor the GHG award activity after Seattle City Light joins on April 1, 2020. If there is a noticeable change in the market, PGE intends to reflect the change through a revision to the implied emission factor. For example, if Seattle City Light's market entry is accompanied with lower GHG award prices, PGE would propose replacing the production weighted implied emission factor with a simple average

[14] As of November 2018, the CAISO restricts the amount of capacity that can be deemed delivered to California to the upper economic bid limit of a resource minus the resource's submitted base schedule.

implied emission factor. The change would reduce the GHG benefit from $3.0 million to $1.9 million.

Q. Please describe PGE's forecast for grid management charges in its 2020 NVPC forecast.

A. PGE's forecast is $1.0 million. PGE assumes 2019 actual settlement results are a reasonable basis for 2021 grid management charge costs.

Q. Please summarize PGE's proposal for Western EIM benefits in the 2021 NVPC forecast.

A. PGE's gross EIM benefit in its 2021 NVPC forecast is $7.0 million. After adjusting for PGE's grid management charge forecast, PGE's net EIM benefit in the 2021 NVPC is approximately $6.0 million.

B. Gas Optimization

Q. What precipitated the gas optimization modeling in PGE's 2021 NVPC forecast?

A. In PGE's 2020 AUT, AWEC proposed that PGE adjust its 2020 NVPC forecast to incorporate gas trading benefits that can potentially be realized given PGE's ability to access various natural gas markets through its pipeline gas transportation rights and by operating the North Mist gas storage facility. In UE 359, the Commission adopted a stipulation with parties agreeing that PGE would hold a gas optimization workshop prior to filing the 2021 AUT and propose a method for forecasting gas optimization modeling within the initial 2021 AUT filing.

Q. Has this workshop occurred?

A. Yes. PGE hosted the gas optimization workshop on March 4, 2020. During the workshop, PGE presented to OPUC Staff, AWEC, and CUB our proposed gas optimization method and described the necessary MONET modeling updates.

Q. What changes to gas modeling is PGE including in the 2021 NVPC forecast?

A. PGE is including modeling enhancements to forecast gas optimization benefits for: 1) PGE's gas operations on the Gas Transmission Northwest (GTN) Pipeline (Gas Resale Benefits); and 2) PGE's gas operations at the North Mist gas storage facility and the Port Westward (PW)/Beaver complex (Gas Storage Optimization).

Q. Please summarize the changes made in MONET to forecast a gas optimization benefit.

A. To incorporate the gas optimization modeling, PGE evaluated the fuel demand at the PW/Beaver complex based on expected dispatch in 2021, updated the gas supply to include the North Mist gas storage, and determined appropriate Beaver plant parameters to account for fuel supply constraints. We describe the MONET updates in more detail below, starting on page 24.

Gas Resale Benefits

Q. Please provide an overview of PGE's gas operations on the GTN pipeline.

A. The GTN pipeline delivers gas sourced from the western Canadian sedimentary basin and Canadian Rocky Mountains to gas markets in Washington, Oregon, and California. PGE has firm gas transportation rights for approximately 119,500 dth/day on the GTN pipeline to access the AECO and Stanfield gas hubs and meet the fueling requirements for the Coyote Springs and Carty gas thermal plants.

Q. Where are the AECO and Stanfield gas hubs located?

A. The AECO gas hub is located in southern Alberta, Canada and is one of the largest in North America, with substantial production and storage capability and an extensive network of export pipelines. Stanfield is located near the Washington/Oregon border at the intersection of the Northwest pipeline and the GTN pipeline.

Q. How do the AECO and Stanfield gas prices compare?

A. The AECO hub has historically been one of the lowest cost locations in North America for purchasing natural gas, as the Canadian province of Alberta is a supply basin and there is a cost for transporting Alberta's gas supplies across North America. Stanfield on the other hand is usually more expensive due to the illiquid nature of trading at the hub.

Q. To what gas hub is PGE dispatching the Carty and Coyote thermal plants in MONET?

A. While the location of the Stanfield hub is physically closer in location to Carty and Coyote Springs, PGE has firm delivery rights from AECO and thus, PGE provides customers with the benefit of forecasting the dispatch of Carty and Coyote Springs in MONET using cheaper AECO gas prices.

Q. Can PGE realize additional benefits from optimizing the gas operations on the GTN pipeline?

A. Potentially. PGE may be to able realize additional benefits from capturing gas price differentials between AECO and Stanfield when there is a gas supply surplus on the GTN pipeline that can be traded at Stanfield.

Q. How do you determine the gas optimization margins on the GTN pipeline?

A. PGE first evaluates the expected daily average gas supply on the GTN pipeline given our transportation rights and the GTN planned maintenance compared to the expected daily average gas demand at Carty and Coyote based on MONET projections. If there is a gas surplus in any given day, MONET will sell that surplus at Stanfield and potentially realize a power cost benefit. Alternatively, if market heat rates are causing MONET to dispatch Carty and Coyote in excess of PGE's gas supply and there is a gas deficit, MONET will fill that deficit with delivered gas purchased at a premium, thereby reducing the total gas benefit.

Q. When does PGE expect to have gas supply surplus on the GTN pipeline?

A. PGE forecasts a gas supply surplus that can be traded at Stanfield when Coyote and Carty are on planned maintenance or economically displaced in MONET.

Q. What price does PGE model for the Stanfield gas hub?

A. The Stanfield gas hub does not publish a natural gas forward price curve, so PGE determined the Stanfield price to be the lesser of Sumas or Rockies market prices.

Q. Please explain why.

A. [redacted]

Q. Can MONET forecast power cost benefits from monetizing price spreads between AECO and Stanfield when Carty and Coyote experience forced outages?

A. No. MONET simulates the dispatch of PGE resources to meet customer loads based on the principle of economic dispatch in a normalized environment. Forced outages are not normal events that can be planned for. PGE cannot forecast power cost benefits from capturing gas price spreads between AECO and Stanfield when Carty and Coyote experience forced outages for several reasons:

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[15] PGE Exhibit 102 provides a map showing the relative geographic locations of the gas market hubs that PGE can access given our gas pipeline rights.

1. During a forced outage PGE maintains the gas transportation capacity for Carty and Coyote to fuel the plants when they return to service;
2. PGE does not have the ability to forecast plant forced outages and plan for trading activities at the Stanfield hub on a day-ahead basis because forced outage events occur randomly and often have short durations; and
3. PGE does not have the ability to plan for trading activities at Stanfield on an intra-day basis due to the illiquidity of the market.

Q. What other constraints does PGE face when forecasting gas resale optimization benefits?

A. PGE's ability to trade gas at Stanfield is also limited in certain months due to maintenance activities on the GTN pipeline. GTN performs maintenance on certain segments of the pipeline between April and November of each year. During the times when maintenance is performed, the pipeline capacity is reduced by three to 12 percent for multiple periods of time that range in duration between one and 14 days, hampering PGE's ability to use its transportation rights for trading activities.

Q. What is the 2021 gas resale optimization forecast?

A. Based on February 28, 2020 forward price curves, PGE's initial estimate for gas resale optimization benefits in 2021 is approximately $0.6 million. PGE expects that the amount will change in subsequent power cost updates.

Natural Gas Storage Optimization

Q. How is PGE planning to optimize activities at the North Mist gas storage facility and the PW/Beaver complex?

A. PGE is planning to evaluate storage injection and withdrawal cycles relative to forward gas prices at the Sumas and Rockies gas markets to realize benefits based on seasonal price differentials and subject to pipeline transportation rights, gas storage constraints, and PW/Beaver expected dispatch.

Q. What are PGE's gas transport rights to fuel the North Mist gas storage and the PW/Beaver complex?

A. PGE holds a total of 103,305 dth/day of firm transportation rights on the Northwest Pipeline for firm delivery at the Kelso-Beaver (KB) pipeline to fuel the North Mist gas storage and the PW/Beaver complex that consist of the following:

1. PGE holds firm receipt rights at the Sumas, WA / Huntingdon, BC market (Sumas) of 73,305 dth/day for delivery at the KB pipeline.
2. PGE holds firm receipt rights at the Rockies market of 30,000 dth/day for delivery at the KB pipeline.

Q. Does PGE have sufficient gas supply in North Mist gas storage and pipeline transportation rights to meet the fueling requirements at the PW/Beaver complex?

A. No. PGE does not have sufficient gas supply from firm rights and North Mist gas storage to meet the PW/Beaver complex at full load, at least not for 24 hours each day. Depending on prevalent market heat rates, and without consideration of fuel supply constraints, MONET could dispatch the PW/Beaver complex in excess of PGE's firm pipeline rights and North Mist storage withdrawal capability. For months in which fueling requirements at the

PW/Beaver complex exceed PGE's firm pipeline rights and North Mist storage withdrawal capability, MONET purchases additional non-firm delivered gas. However, PGE has limited access to 31,695 dth/day of non-firm delivered gas available on the Northwest pipeline, especially during winter months due to the heating season. Therefore, MONET does not assume any availability of non-firm delivered gas from December to February.

Q. Please briefly describe the North Mist storage facility.

A. North Mist consists of an underground storage facility, including a 4.1 BCF capacity storage reservoir, along with a 13-mile underground unidirectional gas pipeline to the PW/Beaver complex, with above ground facilities including a well pad, compressor station, and mainline block valve.

The facility is located entirely within Columbia County, Oregon. The gas pipeline originates at North Mist and ends at the Port Westward Industrial Park facilities located approximately five miles north-northeast of Clatskanie, Oregon.

Q. What are the benefits of having gas storage capacity at North Mist?

A. The gas storage services provided by North Mist, in conjunction with PGE's transportation rights on the KB pipeline and non-firm delivered gas, fuel the PW/Beaver complex. To provide flexible capacity, PGE requires a highly flexible and dynamic fuel supply to meet the demands for peaking, load following, and wind integration services. Gas storage withdrawals provide a high degree of intra-day and intra-hour flexibility, which aligns with PGE's need for a flexible and dynamic fuel supply. Additionally, as described in this testimony, the North

Mist gas storage facility allows PGE to capture seasonal natural gas market price differentials to reduce the NVPC forecast.

Q. What are the maximum daily injection and withdrawal rates at the North Mist storage facility?

A. The maximum daily injection rate is 56,000 dth/day and the maximum daily withdrawal rate is 120,000 dth/day. The withdrawal rate decreases based on storage inventory levels from 120,000 dth/day when the reservoir is full to approximately 45,600 dth/day when storage inventory is below 18 percent. However, for reliability purposes, PGE does not intend to allow storage inventories to decrease below approximately 30 percent, or approximately 1.2 BCF, to ensure the Port Westward thermal plant could be dispatched for seven days exclusively on storage gas should a gas pipeline disruption occur. Also, PGE will derate injections and withdrawal rates by 5,000 dth/day to support daily Port Westward 2 (PW2) wind and load following and ancillary services activity.

Q. Please describe the gas storage optimization method.

A. PGE will first evaluate a weighted average cost of gas (WACOG) in storage based on inventory levels and market prices, planning for gas storage injections in months when the natural gas market prices are cheaper. PGE will then withdraw 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. What is the expected gas storage optimization benefit in 2021?

A. With February 28, 2020 market price curves, the gas storage optimization reduces PGE's 2021 NVPC forecast by approximately $2.9 million. PGE expects that the amount will change in subsequent power cost updates.

MONET Modeling Enhancements

Q. What MONET updates are necessary to incorporate gas optimization modeling?

A. To incorporate the gas resale and the gas storage optimizations, PGE will have to update the MONET model to: (1) reflect the limited availability of non-firm delivered gas during winter months; (2) introduce storage gas monthly injection and withdrawal rates; (3) introduce net daily gas limits to the PW/Beaver complex based on available gas supply; and (4) apply limits to Beaver dispatch to reflect PGE's maximum fuel supply capability.

Q. Can MONET currently dispatch the PW/Beaver plants in excess of the total available gas supply?

A. Yes. MONET currently dispatches PGE's thermal plants irrespective of the available gas supply. In fact, current implied market heat rates are causing both PW2 and Beaver plants to be dispatched as baseload resources during several months rather than as peak resources. The additional plant dispatch forecast in MONET results in fuel demand in excess of PGE's capability to supply.

Q. How has the market heat rate changed in recent years, relative to the Beaver heat rate and dispatch in MONET?

A. PGE's 2014 general rate case (UE 262) final price curves provided an implied average market heat rate of 8.3 mmBtu/MWh compared to a MONET Beaver heat rate of 9.26 mmBtu/MWh. The result was that MONET forecasted Beaver to dispatch in 2014 at 72 MWa, with only four months of dispatch over 100 MWa and none over 230 MWa. In comparison, February 28, 2020 market price curves result in a 2021 average market heat rate of 13.5 mmBtu/MWh compared to a 2021 MONET Beaver heat rate of 9.4 mmBtu/MWh. Current market heat rates result in MONET dispatching Beaver in 2021, even with current modeling limits,[16] at 147 MWa with two months over 100 MWa, four months over 200 MWa, and two months over 300 MWa.

Q. Can this impact the gas storage optimization benefit?

A. Yes. The fact that MONET is more often than in the past dispatching the entire PW/Beaver complex as baseload resources can result in less natural gas available to be placed in storage during cheaper months because it is being used to run the plants at a potentially lesser overall benefit to customers.

Q. How is PGE addressing this issue?

A. PGE is updating Beaver plant parameters in MONET to limit the plant's dispatch given our current natural gas pipeline transportation rights and storage capabilities. This will result in more accurate reflection of current gas and electric markets and will ensure that the plant dispatch forecast in MONET is aligned with PGE's actual fuel supply capability.

Q. Please summarize the total 2021 forecast for the gas optimization benefit.

A. Based on February 28, 2020 market prices, PGE forecasts gas optimization benefits of approximately $0.6 million from gas resales on the GTN pipeline and approximately $2.9 million related to North Mist storage and PW/Beaver operations for a total of approximately $3.5 million.

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[16] PGE introduced MONET dispatch limits to Beaver in Docket No. UE 283. MONET modeling logic limits Beaver's dispatch to 12 hours at full load before shutting the plant down.

E. Other Items

Capacity Contracts

Q. Please discuss the background leading up to PGE pursuing bilateral negotiations for short- to medium-term capacity resources.

A. PGE's 2016 Integrated Resource Planning identified a capacity need of approximately 561 MW in 2021 due to a variety of factors, including the planned cessation of coal-fired operations at Boardman at the end of 2020. Based on feedback from the Commission, OPUC Staff, and stakeholders, PGE began pursuing bilateral negotiation with owners of existing regional resources to fill its capacity need.

Q. What additional steps did PGE pursue towards the completion of bilateral negotiations?

A. In August 2017, PGE filed a request to waive the Commission's then Competitive Bidding Guidelines[17] that called for a competitive bidding process for resources greater than 100 MW and a term of more than five years. PGE's waiver request was processed under Docket No. UM 1892. In that filing, PGE requested the Commission grant a waiver to facilitate the purchase of approximately 350 MW to 450 MW of resources. PGE anticipated that executing bilateral agreements in addition to executing additional qualifying facility contracts, procuring energy storage in compliance with House Bill 2193, and realizing the capacity contribution from incremental renewable resources actions would address PGE's medium-term capacity needs. Commission Order No. 17-386 ultimately granted PGE's waiver but required PGE to engage the Commission before advancing offers not identified in the top five ranked indicative offers as presented in the waiver application.

[17] Competitive Bidding Guidelines now require a competitive bidding process for resources greater than 80 MW and a term of more than five years. The changes to OAR 860-89 have been adopted by the Commission through PUC 4-2018 Permanent Administrative Order on August 30, 2018.

Q. What resources did PGE acquire pursuant to Order No. 17-386 granting PGE's waiver described above?

A. PGE entered into three power purchase agreements (PPAs) with two counterparties for firm capacity and energy:

1. PGE entered into a five-year PPA with a counterparty for 100 MW firm capacity with an effective date of January 1, 2019. This PPA was included in the 2019 NVPC forecast and is already reflected in customer prices, initially through OPUC Order 18-405 (2019 GRC).
2. In November 2018, PGE also executed two capacity and energy PPAs with one counterparty. These PPAs are new for 2021 and are included in Step 0E of PGE's initial 2021 NVPC forecast. For more information please see the MFRs.

Q. Are the contracts included in Step 0E of PGE's 2021 initial NVPC forecast in the top five offers as presented in Docket No. UM 1892?

A. Yes. The contracts included in Step 0E of our 2021 initial NVPC forecast are in the top five scoring offers presented in UM 1892.

Q. Does PGE expect to execute other additional capacity agreements during 2020 with a 2021 effective date?

A. Possibly. To further address the capacity deficit that PGE will face when Boardman ceases operations at the end of 2020,[18] PGE is actively pursuing additional firm capacity and may execute one or more agreements that would be effective in 2021. PGE is pursuing capacity agreements with terms of five years or less and therefore not subject to Competitive Bidding Guidelines as provided in Oregon Administrative Rules (OAR), Chapter 860, Division 89.

[18] With Boardman ending operations at the end of 2020, PGE will lose approximately 518 MW net base capacity.

Should PGE determine there is good cause to acquire a resource that would be subject to Competitive Bidding Guidelines, we would submit a request for waiver of applicable Division 89 rules prior to or concurrent with the initiation of the resource acquisition, in accordance with OAR 860-089-0010(2).

Q. Will PGE adjust its 2021 NVPC forecast to incorporate new 2021 capacity agreements in future MONET updates?

A. Yes. Should PGE execute a new capacity agreement with a 2021 effective date, PGE will adjust its 2021 NVPC forecast in a future MONET scheduled update and provide more support information at that time.

QF Energy Derate and Tracker

QF Energy Derate

Q. Why does PGE derate the energy output for QFs expected to come online in 2021?

A. PGE derates the expected energy generation for new QFs expected to achieve commercial operation in 2021 pursuant to Commission Order No. 19-329 issued in PGE's 2020 AUT (UE 359). Parties to UE 359 agreed that PGE will apply a derate on the energy generation of new QFs based on the most recent four-year historical annual average of actual versus projected QF costs.

Q. What derate percentage did PGE apply to the expected generation of new QFs expected to achieve Commercial Operation Date (COD) in 2021?

A. We derated the generation of new QFs by 83 percent.

Q. How many new QFs does PGE include in the initial 2021 NVPC forecast?

A. PGE's 2021 NVPC forecast currently includes four new QF PPAs that indicate COD in Q3 and Q4 of 2021 resulting in a minimal impact to power cost.

Q. What is the power cost impact of the QF derate when applied on the four new QFs 2021 generation?

A. Applying the QF derate on the new 2021 QFs generation decreases the 2021 NVPC forecast by approximately $0.5 million, leading to the overall minimal impact to power costs.

Q. Besides these four new QFs in 2021, is there additional QF energy generation in the 2021 forecast that was not present in the 2020 final NVPC forecast?

A. Yes. In addition to the four new QFs in the 2021 forecast that were not present in the 2020 forecast, there are 29 other QFs that were forecast to come on-line sometime during 2020, resulting in a partial year of generation in the 2020 forecast. Parties to the 2020 AUT (UE 359) agreed that the generation expected from these other QFs be derated by 54 percent in the 2020 NVPC forecast. For the 2021 forecast, MONET is modeling these other 29 QFs for the entire year which would have resulted in additional energy generation in 2021 relative to 2020, if the 54 percent derate were maintained.

Q. What would be the power cost effect due to the additional energy resulting from the other 29 QFs having full-year generation in 2021 vs. part-year in 2020 if PGE maintained the 54 percent derate?

A. Maintaining the 54 percent derate, the power cost effect of the additional energy from the 29 QFs having full-year generation in 2021 would be an increase of approximately $3.8 million above PGE's final forecast of 2020 net variable power costs.

Q. Does PGE also derate the additional energy resulting from the other 29 QFs having full-year generation in 2021 vs. part-year in 2020?

A. Yes. To avoid adding more complexity to the QF track and true up mechanism, PGE is applying the 83 percent QF derate described above to this additional QF generation as well.

Applying the 2021 QF derate on the additional generation from the 29 QFs reduces the 2021 NVPC power cost forecast by approximately $1.9 million.

Q. Are there other QFs that were derated by 54 percent in the 2020 NVPC forecast that PGE is now derating by 83 percent?

A. Yes. PGE derated the output of another 47 QFs that have been forecast to achieve COD prior to 2020 and have yet to be commercially operational.

Q. What is the total power cost reduction associated with the QF derate?

A. Applying the 83 percent derate to the generation of new 2021 QFs and to other QFs that have not achieved COD reduces the 2021 NVPC forecast by approximately $24.5 million. Should these QFs achieve COD without delay, the cost variance between forecast costs and actual costs due to the derate will be subject to the QF track and true up mechanism and included in PGE's 2023 AUT filing. Thus, there remain potentially significant future upward pressure on customer prices from QF activity.

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 accurate 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. Does PGE include a QF refund associated with the QF track and true up mechanism in the 2021 AUT?

A. Yes. PGE will refund approximately $3.3 million associated with QFs forecast to come online in 2019 that experienced delays in their expected COD.

Q. Please explain how you determined the QF refund.

A. First, PGE tracked the online dates of all QFs forecast to achieve COD in 2019. PGE then re-ran the final November 15 NVPC MONET forecast for the 2019 test year replacing the estimated QF CODs with actual recorded CODs. From this, PGE determined the power cost variance to be refunded (or collected) to customers by comparing the original November 15 NVPC MONET forecast for the 2019 test year with the revised version described above. Additionally, in accordance with Commission Order No. 18-405 and for this year only, PGE included in the refund the cure payments received from QFs in 2019 for replacement power purchased by PGE from the market during the 2019 default period after the QFs failed to achieve COD.

Wheatridge

Q. Please briefly describe the Wheatridge Renewable Energy Facility.

A. The Wheatridge Renewable Energy Facility (Wheatridge) is a 300 MW wind generation facility, a 50 MW solar facility, and a 30 MW 4-hour duration energy storage facility located in Morrow County, Oregon. PGE will own 100 MW of the wind generation facility which will be subject to a build-transfer-agreement while the remaining project output will be sold to PGE under two PPAs. The substantial completion of the wind generation facility is currently forecast to occur in Q4, 2020. PGE is monitoring this timeline closely given the possibility of delays due to the COVID-19 pandemic. Should a delay result in changes to the online date of Wheatridge, PGE will adjust the 2021 NVPC forecast accordingly.

Q. Who is responsible for the construction and operation of Wheatridge?

A. Subsidiaries of NextEra Energy, LLC (NextEra or NEE) will build and operate the entire facility and will own 200 MW of the wind facility, along with the solar and battery components.

Q. Please describe the PPA terms between PGE and NEE for Wheatridge.

A. NextEra's 200 MW share of the wind facility, the 50 MW solar facility, and the 30 MW 4-hr battery storage facility make up the balance of the Wheatridge Renewable Energy Facility not owned by PGE. The sale of the output from NextEra's facilities are governed by two PPAs: one for wind and another for the solar and battery storage. The wind PPA has a 30-year contract term beginning upon commercial operation of the wind facilities. The solar component of the solar and storage PPA has a 30-year contract term and the storage component has a 20-year contract term, both beginning upon commercial operation scheduled for December 31, 2021. All prices are non-escalating over the term of the contract and are for specified energy delivered to Morrow Flat. The total project output is a bundled product (energy and associated renewable energy credits - RECs), as such, the project output can be used to meet Oregon renewable portfolio standard (RPS) obligations.

Q. How will Wheatridge affect PGE's initial 2021 NVPC forecast when it begins operation?

A. The initial April 1 MONET forecast for 2021 estimates a Wheatridge wind facility net dispatch benefit of approximately $3.5 million. The 100 MW of PGE-owned wind is expected to provide a $14.8 million power cost benefit and the 200 MW PPA-portion will increase the 2021 power cost forecast by $11.3 million. The Wheatridge net dispatch benefit includes the Wheatridge related transmission costs described in Section E(4).

Q. Do the estimated Wheatridge net dispatch benefits encompass the entire test year?

A. Yes. MONET includes a forecast of Wheatridge wind generation for the entirety of 2021.

Q. What methodology does PGE use to forecast the energy output from Wheatridge?

A. We use the five-year moving average forecast methodology to forecast energy output from Wheatridge, consistent with the methodology introduced in Docket No. UE 266. For this proceeding, all five years of the moving average calculation will be based on the capacity factor used in the RFP scoring process. Similar to the treatment used for Tucannon, PGE will update this annually in future AUT April filings to incorporate full years of actuals as they become available.

Q. Is PGE allowed to change the wind forecasting methodology in this AUT proceeding?

A. No. PGE is precluded from making MONET modeling changes in AUT proceedings unless directed by a Commission Order. Moreover, Commission Order No. 19-329 in PGE's 2020 AUT (UE 359) adopted a stipulation with stipulating parties agreeing to not propose changes to PGE's wind forecasting methodology until our next general rate case.

Q. What costs associated with Wheatridge are modeled in MONET?

A. MONET models a day-ahead forecast error, Bonneville Power Administration (BPA) integration costs, and Point-to-Point (PTP) transmission for the full 300 MW of Wheatridge wind, along with the PPA price for 200 MW of wind, and the costs associated with developer and landowner royalties for the PGE owned portion.

Q. What does MONET currently assume for transmission related to Wheatridge?

A. MONET includes 300 MW of firm PTP transmission rights from BPA and as Wheatridge is within BPA's balancing authority area, MONET assumes the full output of the facility is subject to BPA 30/15 Variable Energy Resources Balancing Services, as modeled within the RFP. However, PGE is working with NEE and BPA to pseudo-tie[19] the project output from the 100 MWs of the wind generation facility that will be owned by PGE. Doing so will allow PGE to move its portion of Wheatridge into PGE's balancing area (i.e., self-integration), resulting in a savings to customers. PGE plans to update MONET for this change when a firm date for the transfer is identified.

Q. What are some of the benefits to NVPC that Wheatridge will provide?

A. Wheatridge will provide renewable energy that will offset market purchases made in MONET. This will decrease PGE's total NVPC. As noted above, the renewable energy provided will help PGE to meet the Oregon RPS targets.

[19] A pseudo-tie is a time-varying energy transfer that is updated in real-time allowing the generator of a Balancing Authority Area (BAA) to physically reside outside the contiguous boundaries of the BAA.

Q. Has PGE included any costs or benefits of the Wheatridge Solar and Storage PPA within its initial 2021 forecast of NVPC?

A. No. The current commercial operation date for this portion of the facility is still forecast to occur December 31, 2021. We are currently monitoring the status of the project and do not have any new information at this point. We expect to include this portion of the project in our 2022 NVPC proceeding. Should circumstances change, we will include any 2021 costs and benefits in this proceeding or through a separate renewable automatic adjustment clause filing at a later date.

Q. Is the recovery of the Wheatridge Renewable Energy Facility revenue requirement currently subject to a regulatory proceeding?

A. Yes. On December 3, 2019, PGE submitted a request for the recovery of the revenue requirement associated with the Wheatridge through PGE's Schedule 122, pursuant to Oregon Revised Statutes (ORS) 757.210 and 469A.120(3). The case is processed under Docket No. UE 370. Specifically, PGE requested the recovery of the fixed costs, O&M costs, income taxes, property taxes, and other fees and costs associated with the PGE ownership portion of Wheatridge wind facility, including any Schedule 125 eligible NVPC prior to 2021.

Q. What is the target date for a Commission decision in Docket No. UE 370?

A. Parties to the docket agreed to a procedural schedule that allows a Commission decision by August 24, 2020.

2021 Transmission Rights

Q. How does the total 2021 transmission cost forecast compare to the final November 15 MONET update for the 2020 NVPC forecast?

A. MONET is forecasting an increase of approximately $14 million in 2021 transmission cost compared to the final 2020 AUT MONET output.

Q. How does MONET calculate the costs of transmission?

A. MONET calculates the monthly cost of transmission for each contract as the product of the applicable BPA rate (PTP, Scheduling Control and Dispatch, etc.) and PGE's capacity or demand for that contract.

Q. What is the increase in 2021 transmission costs related to?

A. The increase in transmission costs is due primarily to 1) additional PTP BPA transmission required to deliver the output from the Wheatridge project to PGE's balancing authority area (BAA), and 2) the expiration of BPA PTP transmission credits PGE has been receiving for the Tucannon wind farm. Additionally, increased BPA PTP and scheduling, dispatch, and control rates that are effective starting October 2021 will raise overall transmission costs, along with the timing related to roll-over rights at Slatt in 2020.

Q. Please describe the additional BPA transmission rights modeled in MONET to support the delivery of Wheatridge generation.

A. MONET includes 300 MW of firm PTP transmission rights from BPA as Wheatridge is an off-system resource and requires transmission on BPA's system in order to deliver the generation output to PGE's BAA.

Q. What is the cost increase associated with the BPA PTP transmission rights modeled MONET to support the delivery of Wheatridge generation?

A. The additional 300 MWs of BPA PTP transmission increases the 2021 NVPC forecast by approximately $6.7 million. The transmission cost associated with the BPA PTP transmission rights is accounted for in the PGE's forecasted power costs and benefits associated with the Wheatridge facility and provided in Section E(3) above.

Q. Please describe the Tucannon transmission credits.

A. As part of the Tucannon wind project, the interconnection agreement was transferred from Puget Sound Energy to PGE. The Tucannon interconnection included a significant amount of BPA network upgrade costs which are refunded to the interconnection customer as credits to offset future transmission service expenses. These credits began being used in 2015, shortly after the facility achieved COD, and BPA applies them to PGE's bill each month to exactly offset the PTP transmission costs for Tucannon. As expected, the credits have been depleted over time and PGE's credit balance is expected to be zero by December 31, 2020.

Q. What is the cost impact associated with the expiring BPA PTP transmission credits?

A. The expiration of the transmission credits for Tucannon increases PGE's 2021 NVPC forecast by approximately $4.7 million annually.

Q. Why is BPA updating its transmission rates?

A. BPA operates on a two-year rate cycle, beginning in October. This means that every two years, BPA holds a rate case to review and update both its transmission and power rates. September 2021 is the end of BPA's current rate cycle and PGE estimated a rate increase of approximately 4.0 percent for PTP service.

Q. How did PGE estimate the BPA PTP transmission rate for the period October 2021 through December 2021?

A. PGE estimated BPA PTP transmission rates for the period October 1, 2021 through December 31, 2021 (part of BP-22) based on the current rate multiplied by the average rate escalation for the nine BPA transmission rate case periods starting with 2002. However, PGE will closely monitor BPA's rate case and will use the most current available BPA information regarding their FY2022 wheeling rates prior to our final NVPC update.

Q. What is the impact of the increased BPA transmission rates in the 2021 NVPC forecast?

A. PGE's forecast of BPA transmission rates going into effect October 2021 increase PGE's 2021 NVPC forecast by approximately $0.9 million.

Q. What is the increase in 2021 transmission costs related to roll over rights at Slatt in 2020?

A. The increase is related to 100 MW of BPA PTP transmission rights at Slatt that became active in May of 2020. These transmission rights will be active for the entire year 2021 resulting in a cost increase of approximately $0.7 million in the 2021 NVPC forecast.

Q. Irrespective of the transmission increase related to the addition of Wheatridge, how does PGE's 2021 transmission portfolio compare to the final 2020 NVPC proceeding?

A. Not accounting for the additional 300 MW of transmission for Wheatridge, PGE's transmission portfolio stays relatively flat, even with the Boardman coal plant closure at the end of 2020. However, as described above in Section E(1), PGE executed several capacity agreements for which transmission is needed to ensure firm delivery and, while Boardman is no longer a part of PGE's portfolio, PGE's load serving obligations have not decreased. As such, PGE plans, redirects, and utilizes its transmission portfolio to ensure that the energy output from its resources and contracts can be reliably delivered to customers. Additionally, due to the long-term fixed nature of transmission rights, it can be difficult to perfectly align transmission needs to a changing portfolio.

Q. How does PGE determine its long-term transmission needs?

A. PGE plans both generation and transmission on a long-term basis to meet projected peak load service obligations. PGE determines our long-term (5-10 year planning horizon) transmission needs such that we meet our portfolio goals to: (a) ensure access to the full generation capability of PGE's remote resources and firm contracts**;** (b) ensure access to the regional markets to allow PGE to meet load service obligations in a cost-effective manner while ensuring reliability and deliverability; and (c) ensure power delivery during a 1-in-10 peak load event. Current estimates for a PGE 1-in-10 load event, including reserve requirements, loss obligations and station service for the next ten years range from approximately 3,975 MW in 2020 to almost 4,200 MW in 2030. This compares to PGE's 2021 average BPA PTP transmission demand of 4045 MW and year-end 2021 demand of 3995 MW.

IV. 2021 Load Forecast

Q. Please summarize PGE's forecast for its 2021 retail load.

A. Table 4 below summarizes actual and forecast deliveries to various customer groups from 2019 through 2021 in thousands of MWhs at average weather conditions. The 2021 forecasted deliveries of 19,717 thousand MWhs are 0.5 percent higher than the forecasted 2020 deliveries due to growth in energy deliveries to the industrial customer class.

Table 4
Retail Energy Deliveries: 2019–2021
(cycle month energy in thousands of MWhs, weather-adjusted)(3)

	2019 Actual (1)	2020 Forecast (2)	2021 Forecast
Residential	7,404	7,432	7,409
General Service	7,304	7,311	7,239
Industrial	4,608	4,822	5,020
Lighting	51	57	49
Total Retail	19,368	19,622	19,717

(1) 2019 actual loads are weather-adjusted according to UE 335 weather methodology
(2) 2020 contains two months of weather-adjusted actuals and remainder of year updated forecast
(3) Numbers may not total due to rounding.

Q. Does this 2021 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.

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 2021?

A. No. PGE does not assume that certain long-term opt-out customers return to cost of service in 2021. PGE assumes all long-term opt-out customers remain on direct access. PGE does assume that short-term (one-year) opt-out customers return to cost-of-service in 2021.

Q. If customers select a long-term opt-out program for 2021, will PGE adjust the load forecast?

A. Yes. PGE will adjust the 2021 cost-of-service load forecast accordingly, as specified in Schedule 125.

Q. Was the 2021 forecast developed using the same models used in Docket No. UE 359?

A. Yes. The same forecast models used in UE 359 were updated with recent actuals through January 2020, the March 2020 (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 2021 test year power cost forecast?

A. The load listed in Table 4 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 5 below reconciles the total system load in Table 4 with the cost-of-service load on a calendar month-basis.

Table 5
Total System Load on Cycle Month at Meter
to Cost-of-Service Load on Calendar Month at Meter: 2021
(thousand MWh)

Total System Load (cycle month)	19,717
Add: Cycle to Calendar Month Difference	(5)
Total System Load (calendar month)	19,712
Less: Schedules 485/489	(2,058)
Cost-of-Service Meter Load	17,654

**Numbers may not total due to rounding.*

Q. What is the corresponding initial cost-of-service bus bar load forecast for 2021?

A. With the addition of line losses to Table 5, the initial bus bar load forecast for 2021 is 18,793.9 thousand MWh, or 2,145 MWa. This load is the basis for the hourly MONET load input data.

Q. Does PGE expect significant electric load impacts due to the COVID-19 pandemic?

A. Yes. The COVID-19 pandemic is expected to cause a significant economic downturn or even recession which could result in shifting load patterns and significant load declines. Although too early to predict the load impact in the Pacific Northwest, evidence from the New England ISO already show a system demand decline of approximately 3 to 5 percent compared to what would normally be expected under weather conditions in the region.

Q. Does the current load forecast incorporate any of the recent market trends associated with the COVID-19 pandemic?

A. No. PGE did not incorporate any potential impact to loads due to the COVID-19 pandemic. PGE is closely monitoring market developments and will provide an update as part of our October filing.

V. Comparison with 2020 NVPC Forecast

Q. Please restate your initial 2021 NVPC forecast.

A. The initial forecast is $436.2 million, or $23.20 per MWh.

Q. How does the 2021 forecast compare with the 2020 forecast used to develop power costs in Docket No. UE 359 and approved through Commission Order No. 19-329?

A. Based on PGE's final updated MONET run for the 2020 test year, the forecast was $393.5 million, or $21.02 per MWh. The initial 2021 NVPC forecast represents an increase of approximately $42.7 million over the 2020 final forecast, which is approximately $2.19 per MWh more than the final forecast for 2020.

Q. What are the primary factors that explain the increase in NVPC forecast for 2021 versus NVPC forecast for 2020 in UE 359?

A. Table 6 shows changes in NVPC by factor between 2020 and 2021.

Table 6
Forecast Power Cost Difference 2021 vs. 2020 ($ Million)

Factor	Effect
Coal Cost and Performance	23.2
Gas Cost and Performance	4.9
Wind Cost and Performance	(9.9)
Contract and Market Purchases	7.9
Market Purchases for Load Change	2.6
Transmission	14.2
Total	**$ 42.7**

* *Numbers may not total due to rounding.*

Q. Please describe each factor in more detail.

A. Below we describe each of the factors that explain the increase in NVPC forecast for 2021 versus the NVPC forecast for 2020 in Docket No. UE 359:

1. The increase of approximately $23.2 million related to coal cost and performance is due to Boardman ending operations in 2020 which results in reduced coal plant generation and decreased market sales of excess generation.

2. The increase of approximately $4.9 million related to gas cost and performance is due to reduced gas plant generation forecast in 2021 relative to 2020 due to gas and electric market price movements. MONET dispatched PGE's gas plants more in 2020 as a result of the market price volatility after the 2019 gas supply disruption due to the Enbridge pipeline rupture in British Columbia.
3. The increase of approximately $7.9 million for contract and market purchases is related to purchases performed to address PGE's energy and capacity needs in 2021. The variance is primarily due to the power cost impact of the additional capacity agreements discussed in Section E(1). Market purchases include costs related to QF generation, which have been derated by 83 percent pursuant to Commission Order No. 19-239 in UE 359. As described in Section E(2), should these QFs achieve COD without delay, the cost variance between forecast costs and actual costs due to the derate will be subject to the QF track and true up mechanism and included in PGE's 2023 AUT filing. Thus, there remain potentially significant future upward pressure on customer prices from QF activity.
4. The increase in the 2021 NVPC forecast is partially offset by a $9.9 million decrease related to wind cost and performance. The decrease is due to additional zero-cost wind generation from Wheatridge resulting in reduced market purchases and added production tax credits. The addition of Wheatridge to PGE's portfolio more than offset the lost PTC generation associated with phase 2 and phase 3 of PGE's Biglow Canyon Wind Farm in 2019 and 2020.
5. The increase of approximately $2.6 million in market purchases is due to a MWa load increase in 2021. As we discuss in Section IV of our testimony, PGE's load forecast

for cost-of-service energy is approximately 2,145 MWa, an increase of 14 MWa from the 2020 NVPC forecast.

6. The increase of approximately $14.2 million related to transmission purchases is mostly due to the expiration at the end of 2020 of the BPA PTP transmission credits for Tucannon and additional BPA PTP transmission required to deliver the output from the Wheatridge project to PGE's BAA. For more details, please see Section E(4).

VI. Qualifications

Q. Mr. Seulean, please describe your qualifications.

A. I received a Bachelor of Arts degree in Accounting from Portland State University. I have been employed at PGE since 2013 in the following positions: Senior Financial Analyst, Manager of Risk Management – Reporting and Controls, and my current position as Manager of Power Cost Forecasting and Analysis. Before joining PGE, I worked at KPMG from 2010 to 2013 as a Certified Public Accountant working in the audit practice. In my current position, I am responsible for managing the economic evaluation and analysis of power supply including net variable power cost forecasting and power Operations risk reporting.

Q. Ms. Kim, please state your educational background and experience.

A. I received a Bachelor of Commerce degree in Industrial Relations Management from the University of British Columbia. I have been employed at PGE since 2011 in the following positions: Merchant Transmission & Operations Analyst, Real Time Merchant Manager, Manager of Term and Daily Trading, and my current position as Senior Director, Energy Supply. Before joining PGE, I worked at Puget Sound Energy from 2003 to 2011 as a Power scheduler, Real Time Trader and Supervisor of Day-Ahead and Real Time Trading. Prior to that, I was employed by BC Hydro/Powerex from 1998 to 2003 in various positions including: Human Resources and Recruitment, Power Scheduling, and Transmission Management. In my current position, I am responsible for managing the Power Operations Trading group that coordinates the NVPC portfolio over the next five-years.

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.

List of Exhibits

PGE Exhibit	Description
101	List of MFRs per Commission Order No. 08-505
102	Map with Natural Gas Pipelines and Market Hub Locations

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

<u>Supporting Documents and Work Papers for the Following</u>

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.

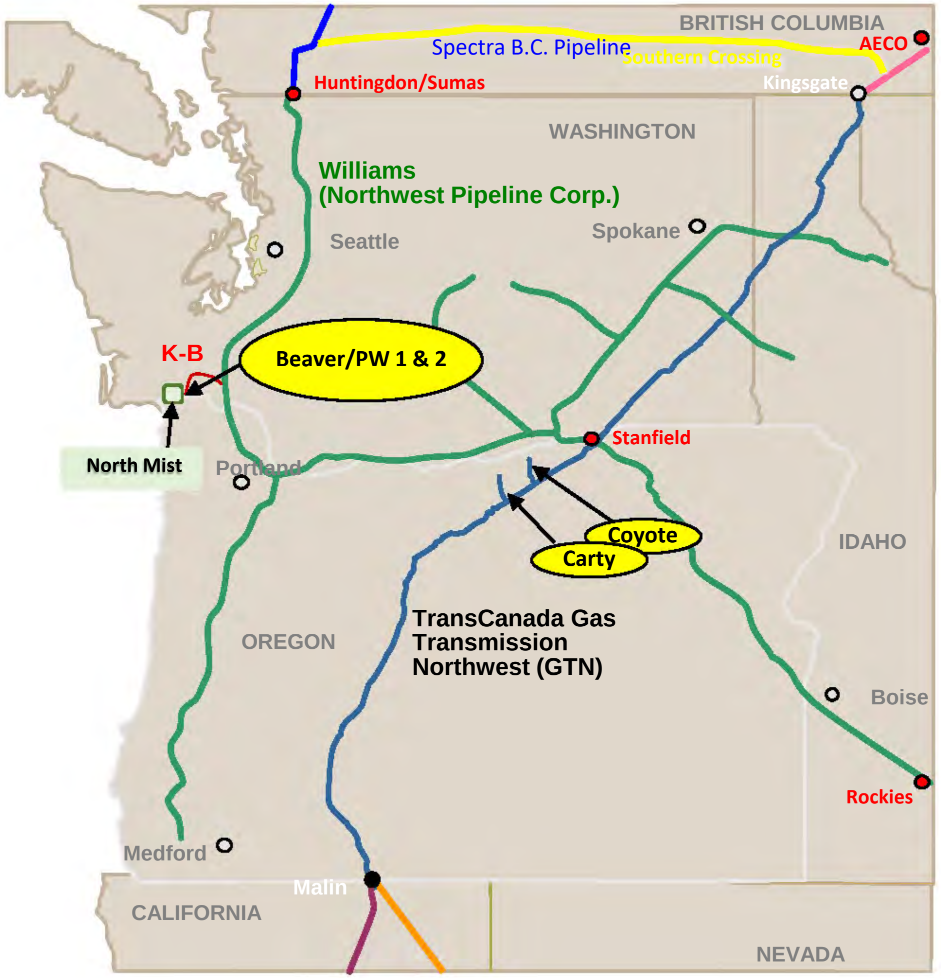
<u>Historical Operating Data</u>

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.

Gas Market Hubs and Pipelines



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200 Speer

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Andrew Speer

April 1, 2020

Table of Contents

I. Introduction and Summary

Q. Please state your name and position.

A. My name is Andrew Speer. I am a Regulatory Consultant in the Pricing and Tariffs Department. My 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, 2021.
- Other supplemental schedule changes.
- 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, Long-Term Transition Adjustment.

PGE will file the final Schedule 125 tariff prices that will incorporate the final updates to Net Variable Power Costs (NVPC) in November 2020. 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 $43.4 million increase in Schedule 125 prices, inclusive of changes in system usage charges?

A. Table 1, below, summarizes the estimated 2021 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	2.1 %
Sch 83 Non-residential 31-200 kW	2.8 %
Sch 85 Secondary 201-4,000 kW	2.9 %
Sch 85 Primary 201-4,000 kW	3.1 %
Sch 89 Primary Over 4,000 kW	3.4 %
Sch 89 Subtransmission Over 4,000 kW	3.2 %
Schedule 90 Over 100 MWa	3.5 %
COS Overall	2.4 %

Q. What other price changes do you expect to occur on January 1, 2021?

A. I anticipate changes to various supplemental schedules to occur on January 1, 2021:

1. The Schedule 102, Regional Power Act Credit, may change due to actual loads being different than forecasted loads for 2020. Any balance will carry over to 2021.
2. Schedule 105, Regulatory Adjustments, may become a larger credit to customers due to the addition of R&D tax credits.
3. Schedule 109, Energy Efficiency Funding Adjustment, may have price changes because the Energy Trust may request to modify the level of funding for energy efficiency. PGE will obtain more information from the Energy Trust this summer.
4. The Schedule 122, Renewable Resource Automatic Adjustment Clause, prices will be revised to remove the NVPC amounts included in 2020. Those NVPC will be included in Schedule 125 for 2021.

5. Schedule 123, Decoupling, will be a higher charge for both Schedule 7 and 32 customers, and a charge for Schedule 83 customers in 2021. PGE does not yet have enough information to develop estimates of the lost revenue recovery portion of Schedule 123 applicable to other nonresidential rate schedules.
6. Schedule 131, Oregon Corporate Activity Tax, may change based on rules being developed by the state.
7. Schedule 132, Federal Tax Reform Credit, will be set to zero unless it results in a material remaining unamortized balance. If the remaining balance is less than $1 million it will be moved to a residual balance account and amortized through Schedule 105.
8. Schedule 135, Demand Response Cost Recovery Mechanism, may increase due to increasing customer participation in applicable programs.
9. Schedule 136, Oregon Community Solar Program Start-Up Cost Recovery Mechanism, may increase due to the addition of cost recovery for participant compensation in the program.
10. Schedule 145, Boardman Power Plant Decommissioning Adjustment, will either decrease or be set to zero. Additional information regarding decommissioning activity is expected this summer.

Q. With the supplemental items that are known as described above, what is the expected total price change by major rate schedule including these items?

A. I've only included estimates related to Schedules 123 and 132 in addition to the changes in Schedule 125. Table 2, below, summarizes the estimated 2021 COS base rate impacts for selected rate schedules.

Table 2
Estimated Base Rate Impacts Including Schedules 125, 123*, and 132

Schedule	Rate Impact
Sch 7 Residential	4.5 %
Sch 32 Small Non-residential 30 kW or less	4.2 %
Sch 83 Non-residential 31-200 kW	4.4 %
Sch 85 Secondary 201-4,000 kW	4.1 %
Sch 85 Primary 201-4,000 kW	4.3 %
Sch 89 Primary Over 4,000 kW	4.5 %
Sch 89 Subtransmission Over 4,000 kW	4.3 %
Schedule 90 Over 100 MWa	4.6 %
COS Overall	4.4 %

*Schedule 123 price changes only include those related to Schedules 7, 32, and 83.

II. Calculation of Schedule 125 Prices

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

A. I determine the Schedule 125 amount by comparing the projected 2021 NVPC to the amount of NVPC that is recovered through the NVPC portion of current energy prices (NVPC prices), multiplied by the 2020 load forecast by schedule (NVPC revenues). The difference between 2021 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 $43.4 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 2 of PGE Exhibit 201 demonstrates the calculation. I 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 2021. For 2021, I project NVPC revenues of $436.2 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. I 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 2021 Base Generation Revenues?

A. I present this calculation, which is simply the 2021 projected energy billing determinants times the tariff energy prices, on page 2 of PGE Exhibit 201.

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. I propose this because it is consistent with Special Conditions 1 and 2 of Schedule 129. These Special Conditions specify that PGE annually true-up the collections or credits related to prospective Schedule 129 payments made by long-term direct access (LTDA) customers at the time that PGE files final rates for Schedule 125.

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

A. Consistent with Special Condition 1 of Schedule 129, I allocate the Schedule 129 payments received from LTDA customers to all customers on the basis of equal cents per kWh. I then compare these allocations of 2021 Schedule 129 payments to the amount that is currently embedded in the System Usage and Distribution prices determined in PGE's most recent general rate case, Docket No. UE 335. For Schedules 85, 89, 90 and their direct access equivalent schedules, the System Usage Charges are expected to increase by 0.06 mills/kWh. For other schedules, the System Usage or Distribution Charges are also expected to increase by 0.06 mills/kWh. PGE Exhibit 203 provides detail regarding the price change calculations.

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

A. Should additional enrollment in LTDA occur in in the September 2020 LTDA enrollment window for service commencing in 2021, PGE will allocate the additional Schedule 129 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 Schedule 129 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. I propose one change to the Annual Updates section of Schedule 125.

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

A. I propose to modify the language regarding cost associated with wind integration to, "costs associated with integrating variable energy resources." While PGE did not model other variable energy resources in this initial filing, it may add other resources. Integration of variable energy resources is not limited to wind and reflects the realities of PGE's system more holistically.

Q. Does this conclude your testimony?

A. Yes.

V. Qualification

Q. Mr. Speer, please describe your qualifications.

A. I received my Bachelor and Master of Science degrees in Economics from Portland State University in 2007 and 2009. I have been employed at PGE since 2018, working as a Regulatory Consultant in the Rates and Regulatory Affairs department. Prior to joining PGE, I worked as a senior rates analyst at NW Natural, working on cost of service and rate design; and prior to that, I worked at the Bonneville Power Administration, working as an economist in the Residential Exchange Program, enterprise risk management, and long-term energy sales and purchases workgroups.

List of Exhibits

PGE 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	2021 Calendar COS Energy MWh	2021 Base Generation Revenues	Generation Allocation	2021 Base NVPC Revenues	Sch 125 Allocation	2021 NVPC Revenues	2021 Sch 125 Price mills/kWh	2021 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	7,411,905	$476,190	45.65%	$167,213	$32,810	$200,022	4.43	$32,835	7,407,681	$32,816	13,037,518	32,816,026	$19,778,508
Schedule 15	15,216	$745	0.07%	$261	$51	$312	3.37	$51	15,216	$51	20,389	51,278	$30,888
Schedule 32	1,545,276	$90,275	8.65%	$31,555	$6,220	$37,774	4.03	$6,227	1,547,259	$6,235	2,475,614	6,235,453	$3,759,839
Schedule 38	31,364	$1,689	0.16%	$591	$116	$707	3.71	$116	31,417	$117	46,183	116,557	$70,374
Schedule 47	19,661	$1,395	0.13%	$488	$96	$584	4.89	$96	19,659	$96	38,138	96,132	$57,994
Schedule 49	60,185	$4,254	0.41%	$1,488	$293	$1,781	4.87	$293	61,097	$298	117,917	297,542	$179,625
Schedule 83	2,832,010	$164,856	15.80%	$57,745	$11,359	$69,103	4.01	$11,356	2,834,241	$11,365	4,506,443	11,365,305	$6,858,862
Schedule 85-S	2,130,949	$120,931	11.59%	$41,831	$8,332	$50,163	3.91	$8,332	2,131,798	$8,335	3,304,286	8,335,329	$5,031,042
Schedule 85-P	692,734	$38,263	3.67%	$13,363	$2,636	$15,999	3.81	$2,639	700,250	$2,668	1,057,377	2,667,952	$1,610,575
Schedule 89-S	0	$0	0.00%	$0	$0	$0	3.63	$0	0	$0	0	0	$0
Schedule 89-P	397,037	$20,494	1.96%	$7,139	$1,412	$8,551	3.56	$1,413	399,963	$1,424	563,947	1,423,867	$859,920
Schedule 89-T	115,684	$5,732	0.55%	$2,052	$395	$2,447	3.41	$394	121,684	$415	166,706	414,941	$248,234
Schedule 90	2,346,421	$115,839	11.11%	$42,001	$7,981	$49,982	3.40	$7,978	2,332,585	$7,931	3,148,990	7,930,789	$4,781,799
Schedule 91	46,460	$2,276	0.22%	$796	$157	$953	3.37	$157	46,460	$157	62,256	156,570	$94,314
Schedule 92	2,634	$135	0.01%	$47	$9	$56	3.52	$9	2,634	$9	3,688	9,272	$5,584
TOTAL	17,647,535	$1,043,073	100.00%	$366,568	$71,868	$438,436		$71,898	17,651,942	$71,917	28,549,453	$71,917,011	**$43,367,558**
										Check	$0	$0	$0

2021 NVPC ($000)	$436,207
2021 NVPC Revenues at Current Prices ($000)	$366,568
Change in NVPC	$69,639
Revenue Sensitive Adj. 3.2%	$2,228
Sch 125 Revenue Requirement	$71,868

PORTLAND GENERAL ELECTRIC
Calculation of Generation and NVPC Revenues

Schedule	2021 Calendar MWh	UE 335 Energy Price	2021 Base Energy Revenues	NVPC Price	2021 NVPC Revenues	2021 Cycle MWh	2021 Cycle to Calendar Ratio
Sch 7							
Block 1	6,429,888	63.29	$406,948	22.56	$145,058	6,426,224	0.999430
Block 2	982,016	70.51	$69,242	22.56	$22,154	981,457	0.999430
Sch 15	15,216	48.98	$745	17.13	$261	15,216	1.000000
Sch 32	1,545,276	58.42	$90,275	20.42	$31,555	1,547,259	1.001283
Sch 38							
On-peak	17,012	60.70	$1,033	18.84	$320	17,040	1.001680
Off-peak	14,353	45.70	$656	18.84	$270	14,377	1.001680
Sch 47	19,661	70.94	$1,395	24.82	$488	19,659	0.999889
Sch 49	60,185	70.68	$4,254	24.73	$1,488	61,097	1.015156
Sch 83							
On-peak	1,861,890	63.35	$117,951	20.39	$37,964	1,863,356	1.000788
Off-peak	970,120	48.35	$46,905	20.39	$19,781	970,884	1.000788
Sch 85-S							
On-peak	1,397,899	61.91	$86,544	19.63	$27,441	1,398,456	1.000398
Off-peak	733,050	46.91	$34,387	19.63	$14,390	733,342	1.000398
Sch 85-P							
On-peak	432,950	60.86	$26,349	19.29	$8,352	437,647	1.010849
Off-peak	259,784	45.86	$11,914	19.29	$5,011	262,603	1.010849
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	235,272	57.73	$13,582	17.98	$4,230	237,006	1.007370
Off-peak	161,765	42.73	$6,912	17.98	$2,909	162,957	1.007370
Sch 89-T							
On-peak	58,087	57.02	$3,312	17.74	$1,030	58,087	1.000000
Off-peak	57,596	42.02	$2,420	17.74	$1,022	57,596	1.000000
Sch 90							
On-peak	1,345,022	55.77	$75,012	17.90	$24,076	1,337,091	0.994104
Off-peak	1,001,399	40.77	$40,827	17.90	$17,925	995,494	0.994104
Sch 91/95	46,460	48.98	$2,276	17.13	$796	46,460	1.000000
Sch 92	2,634	51.09	$135	17.88	$47	2,634	1.000000
Totals	17,647,535		$1,043,073		$366,568	17,645,942	0.99991

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 Transition Adjustment
2021

ALLOCATION OF TRANSITION ADJUSTMENT

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 7	7,407,681	38.9%	($7,474)	(1.01)
Schedule 15	15,216	0.1%	($15)	(1.01)
Schedule 32	1,547,259	8.1%	($1,561)	(1.01)
Schedule 38	31,417	0.2%	($32)	(1.01)
Schedule 47	19,659	0.1%	($20)	(1.01)
Schedule 49	61,097	0.3%	($62)	(1.01)
Schedule 83	2,834,241	14.9%	($2,860)	(1.01)
Schedule 85-S	2,483,711	13.1%	($2,506)	(1.01)
Schedule 85-P	926,074	4.9%	($934)	(1.01)
Schedule 89-S	11,052	0.1%	($11)	(1.01)
Schedule 89-P	999,245	5.3%	($1,008)	(1.01)
Schedule 89-T	307,371	1.6%	($310)	(1.01)
Schedule 90-P	2,332,585	12.3%	($2,353)	(1.01)
Schedules 91/95	46,460	0.2%	($47)	(1.01)
Schedule 92	2,634	0.0%	($3)	(1.01)
TOTAL	19,025,701	100.00%	($19,196)	(1.01)
		TARGET	($19,196)	

Change in Schedule 129 Transfer Payment Amount 2021

Schedules	2019 mills/kWh	2021 mills/kWh	Change mills/kWh	Tariff Category
Schedule 7	(1.07)	(1.01)	0.06	Distribution
Schedule 15	(1.07)	(1.01)	0.06	Distribution
Schedule 32	(1.07)	(1.01)	0.06	Distribution
Schedule 38	(1.07)	(1.01)	0.06	Distribution
Schedule 47	(1.07)	(1.01)	0.06	Distribution
Schedule 49	(1.07)	(1.01)	0.06	Distribution
Schedule 83	(1.07)	(1.01)	0.06	System Usage
Schedule 85-S	(1.07)	(1.01)	0.06	System Usage
Schedule 85-P	(1.07)	(1.01)	0.06	System Usage
Schedule 89-S	(1.07)	(1.01)	0.06	System Usage
Schedule 89-P	(1.07)	(1.01)	0.06	System Usage
Schedule 89-T	(1.07)	(1.01)	0.06	System Usage
Schedule 90-P	(1.07)	(1.01)	0.06	System Usage
Schedules 91/95	(1.07)	(1.01)	0.06	Distribution
Schedule 92	(1.07)	(1.01)	0.06	Distribution
TOTAL				

Total Change in Distribution/System Usage Charge 2021

Schedules	Sys. Usage Current mills/kWh	Sch 129 Change mills/kWh	2021 Sys. Usage mills/kWh	Category
Schedule 7	2.08	0.06	2.14	Distribution
Schedule 15	10.34	0.06	10.40	Distribution
Schedule 32	1.77	0.06	1.83	Distribution
Schedule 38	2.24	0.06	2.30	Distribution
Schedule 47	4.05	0.06	4.11	Distribution
Schedule 49	2.61	0.06	2.67	Distribution
Schedule 83	6.89	0.06	6.95	System Usage
Schedule 85-S	0.87	0.06	0.93	System Usage
Schedule 85-P	0.83	0.06	0.89	System Usage
Schedule 89-S	0.92	0.06	0.98	System Usage
Schedule 89-P	0.89	0.06	0.95	System Usage
Schedule 89-T	0.87	0.06	0.93	System Usage
Schedule 90-P	0.44	0.06	0.50	System Usage
Schedules 91/95	2.58	0.06	2.64	Distribution
Schedule 92	1.00	0.06	1.06	Distribution
Schedule 515	9.14	0.06	9.20	Distribution
Schedule 532	0.32	0.06	0.38	Distribution
Schedule 538	0.91	0.06	0.97	Distribution
Schedule 549	0.84	0.06	0.90	Distribution
Schedule 583	5.44	0.06	5.50	System Usage
Schedule 485/585-S	(0.38)	0.06	(0.32)	System Usage
Schedule 485/585-P	(0.39)	0.06	(0.33)	System Usage
Schedule 489/589-S	(0.22)	0.06	(0.16)	System Usage
Schedule 489/589-P	(0.25)	0.06	(0.19)	System Usage
Schedule 489/589-T	(0.25)	0.06	(0.19)	System Usage
Schedule 490/590	(0.77)	0.06	(0.71)	System Usage
Schedule 491/495/591/595	1.38	0.06	1.44	Distribution
Schedule 492/592	(0.26)	0.06	(0.20)	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 ~~wind integration~~integrating variable energy resources.
- Forward market prices for both gas and electricity.
- 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.