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April 1, 2019

Email / Fed Ex
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Filing Center
Public Utility Commission of Oregon
201 High Street, SE Ste. 100
PO Box 1088
Salem, OR 97308-1088

RE: UE _____ In the Matter of Portland General Electric Company's 2020 Annual Power Cost Update Tariff (Schedule 125)

Attention Filing Center:

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

- **Direct Testimony of**:
  - Mike Niman, Cathy Kim, Greg Batzler (PGE / 100) and Exhibit 101
  - Robert Macfarlane (PGE / 200) and Exhibits 201 - 205

- **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.

PGE's initial forecast of 2020 net variable power costs is $422.0 million. PGE's preliminary estimate of base rate impacts is an increase effective January 1, 2020 of about 3.5%.

Sincerely,

Jay Tinker

Jay Tinker
Director, Rates and Regulatory Affairs

JT/np
cc: UE 335 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PORTLAND GENERAL ELECTRIC COMPANY's 2020 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, 2019.

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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, 2020

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits

April 1, 2019

UE ___ / PGE / 100
Niman – Kim – Batzler

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX

Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Michael Niman
Cathy Kim
Greg Batzler

April 1, 2019

Table of Contents

I. Introduction

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

A. My name is Mike Niman. My position at PGE is Manager, Financial 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 2020 Net Variable Power Costs (NVPC). We discuss several of the updates included in this initial forecast for 2020, as well as provide an update on PGE's efforts to comply with the Commission's directions in Order No. 18-405 (Docket No. UE 335). We also compare our initial forecast with PGE's final 2019 NVPC forecast and explain why the per unit expected NVPC have increased by approximately $2.93 per MWh.

Q. What is your AUT net variable power cost estimate?

A. Our initial 2020 NVPC forecast is $422.0 million, based on contracts and forward curves as of March 7, 2019. This initial 2020 NVPC forecast represents an increase of $60.5 million relative to our final 2019 NVPC forecast.

Q. What are the primary factors that explain the increase in NVPC forecast for 2020 versus the NVPC forecast for 2019 in Docket No. UE 335?

A. The primary factors contributing to the increase in NVPC include: 1) an increase in Qualifying Facilities (QFs) contract costs; 2) the expiration of federal production tax credits (PTCs) associated with phase 2 and phase 3 of PGE's Biglow Canyon Wind Farm; 3) an increase in coal generation costs related to Boardman operation in 2020; 4) an increase in costs related to market energy purchases due to higher on- and off-peak market forward power prices as of March 7, 2019, compared to the market forward curves modeled in the final 2019 NVPC forecast; and 5) an increase in market purchases due to a 27 MWa load increase in 2020.

Partially offsetting the increasing costs is a decrease to forward gas prices, as the Enbridge pipeline in British Columbia is expected to return to normal operations by 2020, resulting in a reduction to the cost of our gas-fired resources.

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 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: 2020 Load Forecast;
- Section V: Comparison with 2019 NVPC Forecast; and
- Section VI: Qualifications.

II. MONET Model

Q. How did PGE forecast its NVPC for 2020?

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

Q. Please briefly describe MONET.

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

- Retail load forecast, on an hourly basis;
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, operating constraints, emissions control chemicals, and any variable operating and maintenance costs (although not part of 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 2019 general rate case (GRC) power cost forecast, we include certain variable chemical costs, lubricating oil costs, and we include forecasted PTCs. We exclude some variable power costs, such as certain variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. Based on prior Commission decisions, certain fixed costs, such as excise taxes and transportation charges, are included in MONET. For the purposes of FERC accounting, these items are included with fuel costs in a balance sheet account for inventory (FERC 151); this inventory is then expensed to NVPC as fuel is consumed. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, natural gas, fuel and associated financial instruments.

Q. Do the minimum filing requirements (MFRs) provide more detailed information regarding the inputs to MONET?

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop our initial forecast of 2020 NVPC. Commission Order No. 08-505 adopted a list of MFRs for PGE in AUT filings and general rate case filings. 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, Annual Power Cost Update (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;
- 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,[1] 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; and
- Projections of State and Federal Tax Credits.

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

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

[1] Per Commission Order No. 10-410, PGE is proposing to remove the ability to update thermal plant variable operation and maintenance from Schedule 125. For more details see PGE Exhibit 200.

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 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 successful participation in the Western EIM on October 1, 2017. PGE concluded its first full calendar year of EIM participation in December 2018.

Q. How does participation in the EIM reduce PGE's actual NVPC?

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

[2] In addition to PGE other active participants in the Western EIM are: CAISO, PacifiCorp, NV Energy, Arizona Public Service, Puget Sound, Powerex, and Idaho Power Company. Planned participants are: Balancing Authority of Northern California/SMUD (2019), Los Angeles Department of Power & Water (2020), Salt River Project (2020), Seattle City Light (2020), Public Service Company of New Mexico (2021), and Northwestern Energy (2021).

[3] There are also indirect benefits associated with PGE's ability to self-integrate its variable energy resources on a sub-hourly basis rather than incurring costs related to BPA's variable energy resource balancing service (VERBS).

resources when EIM prices are low. PGE exports power to the EIM, earning net revenues, when EIM prices are higher than PGE's generation production costs.

Due to load and resource diversity across the EIM footprint, PGE also can attain sub-hourly dispatch savings through lower flexible ramping requirements in the real-time market. While the EIM includes design elements that require PGE to maintain sufficient resources and flexible ramping to serve the energy and capacity needs of its customers prior to commencing each hour, CAISO calculates a flexible ramping requirement for the entire EIM footprint that accounts for transfer capabilities and can be less than the sum of the individual participants' flexible ramping requirements (i.e., an EIM Diversity Benefit). This lower flexible ramping requirement can provide PGE with additional dispatch flexibility and lead to greater sub-hourly dispatch cost savings.

Finally, the participants in the EIM can also be awarded greenhouse gas (GHG)-related revenue.[4] To the extent PGE receives GHG revenue associated with its hydro GHG bids, PGE will reduce NVPC. Later in our testimony, we will describe recent changes to the GHG award methodology that PGE anticipates impacting the GHG benefit in the future.

Q. How has PGE estimated the direct Western EIM benefits in its past NVPC forecasts?

A. In past NVPC forecasts, PGE engaged Energy and Environmental Economics, Inc. (E3) to conduct a benefits study. The E3 study estimated the benefits from sub-hourly dispatch savings.[5]

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[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] In its study, E3 identified sub-hourly dispatch savings as having two components: (1) base dispatch cost savings and (2) additional dispatch cost savings associated with PGE maintaining lower reserve requirements.

Q. In the 2019 GRC, did the parties dispute the methodology used to determine Western EIM benefits?

A. Yes. Instead of using results from the E3 study, OPUC Staff proposed to use a forecast based on historical data, preferably 12 months of actual results from PGE's participation in the Western EIM.

Q. Did PGE agree with Staff's proposal?

A. No, PGE contended it was too early to begin using actual results from PGE's participation in the Western EIM as the basis for a forecast of PGE's Western EIM benefit. During the 2019 GRC proceeding, PGE did not yet have a full calendar year of actual EIM results that could be evaluated alongside PGE's earlier forecast estimates.

Q. Please summarize PGE's direct benefits from EIM participation in calendar year 2018.

A. PGE's net Western EIM benefit in 2018 can be organized into the categories listed in Table 1 below.

Table 1
2018 Net Direct Benefits Western EIM Participation

	NVPC Net Benefits	
1	Sub-Hourly Dispatch Savings	$6.3 million
2	Hydro GHG Revenue	$1.6 million
3	CAISO Grid Management Charges[6]	($0.9 million)
	Total	**$7.0 million**

[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.

Q. Are the actual results for 2018 sub-hourly dispatch savings and PGE's forecast for 2018 sub-hourly dispatch savings similar?

A. Yes. PGE's forecast for 2018 EIM benefits was submitted in OPUC Docket No. UE 319 (UE 319). At that time, PGE engaged E3 to conduct a benefits study in order to estimate benefits that directly result from PGE's participation in the Western EIM. The E3 study estimated the benefits from sub-hourly dispatch savings.[7] PGE's estimate in UE 319 for sub-hourly dispatch savings was $5.6 million.

Q. Did PGE forecast GHG awards in its earlier EIM benefits?

A. No. PGE did not forecast this benefit in its prior forecasts, because PGE continued to use the production cost model approach employed by E3,[8] which did not seek to model the GHG award methodology employed by CAISO. Additionally, PGE's estimate of benefit (without GHG awards) was between 1 percent to 2 percent of net variable power costs, a range we view as a reasonable expectation for net variable power cost impacts from EIM. However, as 2018 actual data shows, the benefits from hydro GHG awards have been a material component of PGE's EIM benefits. PGE has included a forecast of hydro GHG revenue in its 2020 forecast.

Q. Are the actual results for 2018 CAISO grid management charges and PGE's forecast for 2018 grid management charges similar?

A. No, the actual grid management charges are higher than forecast. While actual grid management charges totaled approximately $0.9 million, PGE's forecast for 2018 CAISO grid management charges submitted as part of UE 319 was approximately $0.4 million. The difference is attributable to: 1) a change in grid management charge rates that CAISO

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[7] In its study, E3 identified sub-hourly dispatch savings as having two components: (1) base dispatch cost savings and (2) additional dispatch cost savings associated with PGE maintaining lower reserve requirements.
[8] PGE used the E3 model to estimate EIM benefits in Docket Nos. UE 308, UE 319, and UE 335.

implemented in 2018, and 2) PGE using estimates of billing determinant quantities in its forecast, because there was not yet actual data available to PGE (i.e., PGE had not yet entered the EIM).

Q. Will PGE use actual data to estimate future Western EIM benefits in its 2020 NVPC forecast?

A. Yes. As part of our 2020 NVPC forecast, we propose using 2018 results, with a select set of adjustments, as a basis for the 2020 forecast. Additionally, PGE proposes using actual results, adjusted for known changes in market rules, as the appropriate basis for forecasting GHG revenue and grid management charges in 2020.

Q. Please describe PGE's forecast for sub-hourly dispatch cost savings in its 2020 NVPC forecast.

A. As we described above, our primary EIM benefit in NVPC (i.e., sub-hourly dispatch savings results in 2018) was consistent with our previously modeled results. Therefore, PGE proposes using actual results ($6.3 million) as a basis for forecasting sub-hourly dispatch savings. Adjusted for inflation, PGE's forecast for sub-hourly dispatch cost savings is $6.6 million.

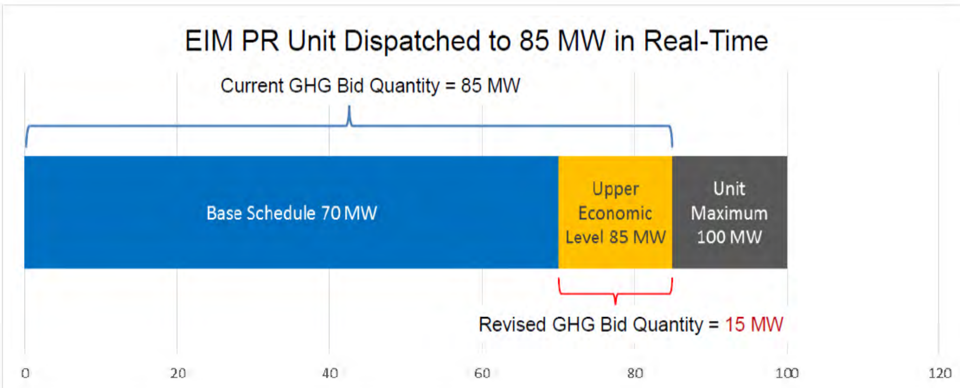
Q. Please describe PGE's forecast for hydro GHG awards in its 2020 NVPC forecast.

A. PGE's forecast of 2020 hydro GHG awards is $0.9 million. To derive the $0.9 million, PGE first reduced its 2018 actual result (i.e., $1.6 million) by 50 percent. In a second step, PGE increased the reduced amount by 7.5 percent per year.

Q. Why did PGE reduce the 2018 actual result by 50 percent?

A. Beginning November 1, 2018, CAISO implemented changes to its GHG bid quantity rules, which will reduce the quantity of GHG awards that an EIM participating resource receives. Figure 1 below illustrates the change. Prior to November 1, 2018, the GHG bid quantity could include the resource's base schedule (e.g., 70 MW in Figure 1). After November 1, 2018, the base schedule is no longer included in the calculation of available GHG bid quantity. In Figure 1, this reduces the GHG bid quantity to only 15 MW (i.e., the Upper Economic Level of 85 MW less the Base Schedule of 70 MW).

Figure 1
Example of GHG Bid Quantity Limit



Source: http://www.caiso.com/Documents/GreenhouseGasEnhancementsforEIMTraining.pdf

PGE selected 50 percent, because it is the approximate reduction in GHG award quantity on PGE's hydro GHG bids beginning December 2018. Table 2 below summarizes the variances year-over-year.

Table 2
Fifteen Minute Market GHG Award Quantity Year over Year

	Year 1	Year 2	% of Year 2 versus Year 1
November	37,488 MW	30,715 MW	82%
December	54,649 MW	28,352 MW	52%
January	53,294 MW	30,389 MW	57%
February	53,868 MW	25,236 MW	47%
Average (Nov – Feb)	49,825 MW	28,673 MW	58%
Average (Dec – Feb)	53,937 MW	27,993 MW	52%

Q. Why is PGE increasing the results by 7.5 percent per year?

A. PGE is assuming inflation of 2.5 percent and a real escalation in GHG prices of 5 percent per year. The 5 percent escalation is consistent with California Air Resource Board regulations, which allow for an annual increase of 5 percent in allowance floor prices.

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

A. PGE's forecast is $0.9 million. To derive the $0.9 million, PGE escalated the 2018 actual results with an inflation assumption of 2.5 percent.

Q. Please summarize PGE's proposal for Western EIM benefits in the 2020 NVPC forecast?

A. PGE's gross EIM benefit in its 2020 NVPC forecast is $7.5 million. After adjusting for PGE's grid management charge forecast, PGE's net EIM benefit in the 2020 NVPC is approximately $6.6 million.

B. California-Oregon Border (COB) Trading Margins

Q. The stipulation resolving NVPC issues in Docket No. UE 335 stated that PGE would "continue to investigate methods to increase the granularity and improve the modeling for COB margins." Please summarize the COB trading margin issue.

A. The COB trading margin issue was first raised in Docket No. UE 294 by the Industrial Customers of Northwest Utilities (ICNU)[9] and subsequently by OPUC Staff in Docket Nos. UE 319 and UE 335. To address parties' concerns, PGE proposed a method to estimate a COB trading margin in the 2017 NVPC forecast (UE 308) and subsequently improved the method in the 2019 general rate case filing (UE 335) by modeling a more granular method of forecasting COB trading margins that accounts for the intra-monthly variability of prices.

[9] Changed name to Alliance of Western Energy Consumers (AWEC) in 2018.

Q. Do you propose a change in methodology at this time?

A. No. PGE's current method uses actual hourly data for trading activities and market forward curves to produce a granular forecast result that is consistent with PGE's actual ability to use its firm transmission access to sell or purchase power at the COB market. Moreover, the COB trading margin methodology captures both daily variation and intra-monthly variability of prices. The daily variation in prices is captured through the modeling of a weighted price shape for COB by hour and day of the week (i.e., weekday, Saturday, or Sunday) and intra-monthly variability of prices is accounted for through the modeling of hourly purchases or sales for each month of the year. As such, we do not propose any changes in modeling at this time.

Q. Is there any refinement to the current method to improve the modeling for COB margins that PGE is proposing with this filing?

A. Yes, we propose to apply a transmission deration on volumes estimated to be transacted at COB in 2020.[10]

Q. Why do you propose applying this transmission capacity deration?

A. The modification is intended to capture expected capacity derations applied by BPA on the N-S path which could limit PGE's transfer capability utilizing its transmission rights. For example, during the first two months of 2019, the total transfer capability of the N-S path has been reduced by 28% on average. This reduction in transfer capability has not been modeled in the 2019 NVPC forecast, but is nonetheless affecting PGE's ability to trade between the Mid-C and the COB power hubs.

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[10] 2020 estimated volumes are determined by taking a three-year rolling average of actual volumes (i.e., 2016 through 2018).

Q. How do you calculate the transmission deration?

A. PGE is proposing to use a three-year rolling average of actual derations applied by BPA on the N-S path to estimate potential future transmission derations. Although BPA routinely plans for derations on the N-S path, they do not provide a forecast of these derations very far into the future, so using historical averages is the best way to estimate a transmission capacity reduction in 2020. The transmission deration is only applied when PGE's usage of its transmission rights (as a percentage of its total 296 MW rights) is greater than BPA's available capacity (as a percentage of the total 4800 MW capacity on the N-S path).

Q. What is the cost impact on the COB trading margin after applying this transmission deration?

A. Applying a transmission capacity deration on forecast purchases and sales quantities reduces the COB trading margin by approximately $0.1 million.

Q. Please describe how PGE forecasts the COB trading margin.

A. Similar to previous NVPC proceedings, PGE includes a pro forma contract in MONET, recognizing PGE's ability to purchase at Mid-C and sell at COB and vice versa (depending on prevailing forward price curves). The pro forma contract's value will be the result of a modeled hourly purchase or sale for each month of the year.

To value the pro forma contract, we use shaped hourly forward curve prices for the Mid-C and COB trading hubs to forecast the price margin. We forecast the pro forma contract quantity based on an analysis of historical trading volumes.

Q. What effect does the COB trading margin method have on PGE's initial 2020 NVPC forecast?

A. The COB trading margin method, including the proposed refinement, results in a forecast of approximately 1.4 million MWh sold and 79,445 MWh purchased, producing an NVPC benefit of approximately $9.0 million. Additional details behind our forecast can be found in our MFRs.

C. Boardman Dispatch in 2020

Q. Please provide a background for why coal operations at Boardman will cease at the end of 2020?

A. PGE is ceasing coal operations at Boardman pursuant to Commission Order No. 10-457 issued in PGE's 2009 Integrated Resource Plan process (Docket No. LC 48). The decision was made due to the Oregon Regional Haze Plan and Oregon Utility Mercury Rule setting forth additional pollution control requirements for Boardman, which required PGE to examine the risks and benefits of making substantial investments in new emissions controls against the risks and benefits of ceasing plant operations and replacing Boardman with alternative energy sources. During the 2009 IRP process (Docket No. LC 48), several options were evaluated, with PGE's final recommendation being to cease Boardman coal operations at the end of 2020.

Q. What is the status of using alternative fuel sources to keep Boardman running after 2020?

A. PGE researched and tested the use of biomass as a replacement fuel source for Boardman but ultimately, after many years of research and development, culminating in a series of test burns, determined that biomass operations were not economically feasible. As such, Boardman will be shutting down by December 31, 2020 and decommissioning activities will begin.

Q. What challenges does PGE face with regards to Boardman operations in 2020?

A. PGE is facing two main challenges:

1. Coal supply constraints during all months in 2020 where Boardman is forecasted to dispatch and Trona constraints during the month of March.
2. Coal inventory management due to Boardman ceasing operations at the end of 2020.

We describe these challenges and how we address them below.

1. Boardman Supply Constraints

Q. Why is there a coal supply constraint during 2020?

A. PGE's operations were significantly impacted by the October 2018 Enbridge gas pipeline rupture in British Columbia. This event has caused constrained natural gas supplies to the region, which has translated to energy market prices exceeding Boardman's dispatch costs. As a result, coal consumption significantly increased during Q4 2018 and Q1 2019. Given that natural gas constraints still remain and are likely to continue during 2019, market prices are forecasted to exceed Boardman's dispatch cost for much of 2019.

Based on PGE's current rail assets, coal deliveries for 2019 and 2020 are expected to be, on average, approximately 97,500 tons per month, of which 90% is allocated to PGE based on PGE's Boardman ownership share. This, coupled with Boardman's increased dispatch, is preventing PGE from building up additional onsite inventories in preparation for 2020. Based on Boardman's forecasted dispatch over the remainder of 2019, PGE anticipates a coal inventory totaling approximately 184,000 tons at the beginning of 2020. As such, the estimated starting inventory for 2020 plus average monthly deliveries of 97,500 tons of coal per month are not sufficient to dispatch Boardman at the economic levels for customers in

2020. Without the delivery constraint, Boardman is forecast to consume approximately 1.3 million tons in Q1 and Q3 of 2020.[11]

Q. How much coal can a train set transport and what is the turnaround time?

A. On average, a train set will transport approximately 13,000 tons of coal. The turnaround time (i.e., the time between Boardman to the mine and back to Boardman) is between 10 to 15 days. The turnaround time can vary significantly based on rail crew availability, weather, congestion on the rail system, and equipment failure on either of the rail segments covering the distance between Powder River Basin in Wyoming and Boardman. As PGE currently owns or leases a total of three train sets, approximately 97,500 tons of coal[12] can be expected per month under normal conditions.

Q. If Boardman is dispatching at higher than expected levels, why hasn't PGE increased coal deliveries for 2019 to help raise inventory for 2019 and 2020?

A. PGE has been actively communicating with both BNSF and Union Pacific[13] in an effort to increase coal deliveries. However, they have communicated that there are constraints within the rail system that are inhibiting additional tonnage being delivered. These constraints include congestion on the rail system and labor shortages involving qualified rail crews. Also, due to coal plant closures, both BNSF and Union Pacific are currently pivoting their operations towards longer-term industries and are less willing to commit assets to support short-term deliveries of coal. Additionally, PGE has attempted to procure additional leased rail cars via our leasing partner Wells Fargo rail. However, Wells Fargo does not have any additional rail

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[11] Assuming the 100% maintenance deration in Q4 of 2020.
[12] 3 train sets * 13,000 tons per train set * approximately 2.5 deliveries per month.
[13] Given the geographic location of Boardman, PGE must utilize both BNSF (from the Powder River Basin to Spokane) and Union Pacific (from Spokane to Boardman) to transport coal.

cars that are compatible with Boardman's coal unloading facility. Boardman's coal unloading facility uses Rotary Dump Gondolas,[14] whereas Wells Fargo's current available rail car inventory only includes Bottom Dump Hoppers.[15] Boardman cannot operate this style of rail cars as they are incompatible with Boardman's loading facility.

Q. How is PGE addressing the coal supply challenge in the 2020 NVPC forecast?

A. To address the coal delivery constraint in 2020, PGE is modeling a maintenance deration in MONET for Q1 and Q3 that limits Boardman's dispatch to the actual amount of coal available on site.

Q. What is the impact of modeling a maintenance deration at Boardman for Q1 and Q3 of 2020?

A. Using the March 7, 2019 curves and the coal supply levels discussed above, Boardman is derated on average by approximately 41.3% for Q1 and 2.1% for Q3 of 2020,[16] which results in a forecasted NVPC increase of approximately $2.5 million.

Q. Is Boardman experiencing any other supply constraints?

A. Yes. Boardman is also experiencing a Trona supply constraint, which is expected to limit the Trona supply to 5,000 tons for 2020.

Q. What is Trona and how is it relevant to Boardman?

A. Trona is a compound used to capture sulfur dioxide emissions (SO_2). Boardman utilizes a derivative manufactured using Trona as part of the plant's emission control process. The consumption rate is approximately 5.88 pounds of Trona derivative for every MWh of energy produced by Boardman at full load.

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14 Rail cars designed with a rotary mechanism, where the rail car is rotated to remove the coal.
15 This style of rail car has a trap door within the floor of the car that opens to release the coal.
16 To address coal supply constraints PGE modeled different maintenance derations for the months of: January (12.1%), February (54.4%), March (57.4%), and September (6.3%).

Q. Why is PGE limiting Trona in MONET to 5,000 tons for 2020?

A. Solvay, the sole supplier producing the Trona derivative most compatible with Boardman's emission control injection systems, recently communicated to PGE that they have contracted their full capacity of the Trona derivative for 2020, with PGE being allocated 5,000 tons. Solvay has also communicated that if another buyer chooses not to purchase their full allocated amount, they will consider selling PGE the unallocated quantity. Additionally, PGE is attempting to find alternative substitutes of Trona derivatives that are compatible with Boardman's emission control injection systems.

Q. What effect does this supply constraint have on 2020 NVPC?

A. For this initial filing, PGE has assumed an annual constraint for Trona. That is, all 5,000 tons of Trona are assumed to be available beginning January 1, 2020. As such, PGE has modeled an additional Boardman maintenance outage related to Trona constraints during a period with the least economic impact to NVPC. This results in an additional 6.9% deration[17] during the month of March 2020, resulting in a $47,000 increase to the 2020 NVPC forecast.

Q. Does PGE expect an update to this issue in a future update?

A. Yes. PGE will continue to update our Trona quantity in future 2020 power cost update filings based on contractual purchase rights for additional Trona derivative from Solvay or alternative Trona derivatives from other suppliers.

[17] Total maintenance deration for March is 64.3% (57.4% for coal supply constraint plus 6.9% for Trona supply constraint).

2. Coal Inventory Management

Q. What additional challenges related to the coal inventory does ending Boardman operations pose for 2020 power costs?

A. Ceasing operations at Boardman will pose significant challenges in order to minimize the coal quantity that will remain in inventory after the plant shuts down. Minimizing the coal quantity remaining in inventory is important for PGE and customers because it reduces the risk of having to pay high coal removal costs, which will ultimately be a part of plant decommissioning, recoverable through Schedule 145 (Boardman Decommissioning Adjustment).

Q. How is PGE planning to operate Boardman in 2020 to minimize the coal remaining after closure?

A. To minimize the coal quantity remaining at December 31, 2020, PGE is targeting September 2020 as the last month of available/planned operation and will plan coal purchases accordingly. This also results in a lower tonnage nomination with the rails for 2020 as PGE is not forecasting to consume coal during Q4 of 2020.

Q. How will PGE model this in MONET?

A. To address the coal inventory management challenge, PGE is modeling a 100% maintenance deration in MONET for the period between October 1 and December 31, 2020.

Q. What is the cost impact for modeling a 100% maintenance deration for the period between October 1 and December 31, 2020?

A. Placing Boardman on a maintenance outage from October through December of 2020 increases forecasted power costs for the initial filing by approximately $3.6 million.[18] However, due to significantly higher coal disposal costs, the increase in power costs is far outweighed by the decrease in the risk of modeling the plant to run, purchasing and nominating transportation of the fuel via rails, and potentially having coal remain on the ground after the plant ceases operations. For example, modeling the plant to run between October 1 and December 31 of 2020 would require PGE to purchase and nominate transportation for approximately 632,000 tons. If the plant was unavailable due to an unplanned outage, or for any other reason, it would cost approximately $24.0 million, or approximately $37.50 per ton, to remove the remaining coal from the site, which would be recovered through Schedule 145.

Q. Could PGE even get that much coal delivered to Boardman between October 1 and December 31, 2020?

A. No. For reasons discussed above in Section III, C, 1, PGE is currently limited to approximately 97,500 tons per month in coal deliveries.[19]

Q. How will PGE address the possibility of some coal remaining on site after September 2020?

A. In the final quarter of 2020, PGE's decision to economically dispatch the plant will take into account the avoided cost of disposing of the remaining coal. As such, if necessary, PGE will

[18] Note that the forecasted power cost impact will change in future updates as a function of forward price curve updates.
[19] At $37.50 per ton in removal and disposal costs, only one month of un-burned coal at PGE's current delivery capacity (i.e., 97,500 tons) would cost approximately $3.7 million to remove from Boardman.

run the plant at higher dispatch costs in order to avoid having to incur even greater costs for removing the remaining coal. If there is coal left on the ground after September 2020, and the plant is economic to run in the last quarter of 2020 taking into account coal disposal costs, PGE is proposing to include the realized benefits as an NVPC reduction in a subsequent AUT proceeding. Removal costs associated with any coal physical inventory left on the ground after December 31, 2020 will be part of the costs to decommission the plant.

Q. Please explain the method by which PGE will determine the potential incremental value and how will this be accounted for in a subsequent AUT?

A. PGE is proposing to file a deferred accounting application and track the power cost difference between actual settled Mid-C hourly prices and plant actual hourly dispatch costs (including fuel costs) from October 1, 2020 until December 31, 2020. PGE would then multiply that difference by the actual plant output and include the total value, if any, that was realized as an NVPC reduction in the 2022 AUT. PGE will determine the total final value after the end of the period between October 1, 2020, and December 31, 2020.

D. Qualifying Facilities

Q. What is the total power cost increase due to QFs in the initial 2020 NVPC forecast compared to the final 2019 NVPC forecast?

A. The combined effect on the 2020 NVPC forecast of new QF contracts and the additional energy generation from other QFs is a total increase of approximately $28 million.[20] The year 2020 also represents the start of the deficiency period for QF Power Purchase Agreements (PPAs) executed under Avoided Costs effective on or before June 1, 2017. This results in

[20] The total incremental NVPC impact of all QF contracts in the initial 2020 forecast is approximately $65.8 million.

higher payments to QF PPAs because, during the deficiency period, QF PPAs are paid for capacity and renewable attributes in addition to energy.

Q. How many new QF PPAs does PGE include in the initial 2020 NVPC forecast?

A. PGE's 2020 NVPC forecast currently includes 21 new QF PPAs that indicate delivery in 2020.

Q. How does PGE model QF PPAs in the initial 2020 NVPC forecast?

A. Similar to UE 335, PGE models QF contracts to begin production based on the Commercial Operation Date (COD) specified in the contract, which is selected by the PPA seller. The achievement of Commercial Operation triggers the applicable on/off-peak avoided cost prices per the executed contract. If a QF PPA has an expected COD on or before December 31, 2020, the associated QF energy and payments are included in the 2020 NVPC forecast. Costs only include the period in which PGE expects the QF to be operational during the test year. For example, if PGE expects the QF to achieve commercial operation on December 1 of the test period, then the net costs associated with energy deliveries from December 1, 2020 through December 31, 2020 are included in NVPC.

Q. What is the power cost impact of the 21 new QF PPAs?

A. Including the 21 new QF PPAs in MONET increases PGE's initial 2020 NVPC forecast by approximately $4.3 million.

Q. Besides these 21 new QFs in 2020, is there additional QF energy generation in the 2020 forecast that was not present in the 2019 final NVPC forecast?

A. Yes. In addition to the new QFs in the 2020 forecast that were not present in the 2019 forecast, there are 77 other QFs that were forecast to come on-line sometime during 2019, resulting in a partial year of generation in the 2019 forecast. For the 2020 forecast, these other 77 QFs are present for the entire year. This results in additional energy generation from those QFs in 2020 relative to 2019.

Q. What is the power cost effect due to the additional energy resulting from the other 77 QFs having full-year generation in 2020 vs. part-year in 2019?

A. The power cost effect of the additional energy from the 77 QFs having full-year generation in 2020 is an increase of approximately $23.7 million above PGE's final forecast of 2019 net variable power costs.

Q. Please restate the combined power cost effect of the 21 new QFs and the additional energy resulting from the other 77 QFs having full-year generation in 2020 vs. part-year in 2019.

A. As mentioned above, the combined effect on the 2020 NVPC forecast of the 21 new QFs and the additional energy generation from the other 77 QFs is a total increase of approximately $28 million.

Q. Did the Commission adopt a method to mitigate the risk of QFs not meeting their expected COD?

A. Yes. In UE 335 PGE proposed, and the Commission approved through Commission Order No. 18-405, a mechanism that would track and true up the actual commercial online dates of newly forecasted QFs with the commercial online date used in MONET's NVPC forecast.

Q. Did PGE file a deferred accounting application to support the QF tracking method?

A. Yes, PGE filed a deferred accounting application in Docket No. UM 1988. In accordance with Commission Order No. 18-405, PGE is tracking the actual online dates of all newly forecasted QFs with the purpose of either refunding to, or collecting from customers, the difference between forecasted and actual online dates. This collection (or refund) would then be deferred if authorized by the Commission in Docket No. UM 1988 to be included with the next scheduled AUT filing.

Q. How will the QF tracking mechanism work for QFs forecast to come online in 2020?

A. For PGE's 2020 NVPC forecast, the QF tracking mechanism will operate as follows:

- During 2019:
  - PGE included in the initial 2020 NVPC forecast all QFs that are expected to achieve COD in 2020 or earlier as identified by the PPA seller.
  - PGE will update its forecast with any known changes through the final November NVPC update.
- During 2020:
  - PGE will track QF CODs to record all actual online dates.
  - PGE will also record any QF CODs not included within the 2020 NVPC forecast.
- During 2021:
  - During Q1 of 2021, PGE will re-run the final 2020 NVPC MONET forecast used to set customer prices, replacing the estimated 2020 QF CODs with the actual CODs recorded during 2020.
  - PGE will record any NVPC difference between the two model runs and place all amounts into a balancing account where they will earn interest at the modified blended treasury rate.[21]

[21] The modified blended treasury rate is the interest rate usually applied on Commission-approved balancing accounts with automatic adjustment clauses that would be similar to the QF tracking mechanism.

- PGE will then include any recorded amounts for 2020 into the April 1, 2021 forecast of PGE's 2022 NVPC.

Q. Are there any amounts recorded in the 2020 NVPC related to the QF track and true-up mechanism?

A. No. PGE's 2021 NVPC forecast will be the first period that includes an NVPC cost or benefit impact related to the QF track and true-up mechanism.

IV. 2020 Load Forecast

Q. Please summarize PGE's forecast for its 2020 retail load.

A. Table 3 below summarizes actual and forecast deliveries to various customer groups from 2018 through 2020 in thousands of MWhs at average weather conditions. The 2020 forecasted deliveries of 19,657 thousand MWhs are 0.9 percent higher than the forecasted 2019 deliveries due to growth in energy deliveries to the industrial customer class.

Table 3
Retail Energy Deliveries: 2018–2020
(cycle month energy in thousands of MWhs, weather-adjusted)(3)

	2018 Actual (1)	2019 Forecast (2)	2020 Forecast
Residential	7,557	7,577	7,628
General Service	7,417	7,351	7,300
Industrial	4,314	4,498	4,671
Lighting	55	57	58
Total Retail	19,651	19,482	19,657

(1) 2018 actual loads are weather-adjusted according to UE 319 weather methodology

(2) 2019 contains one month of weather-adjusted actuals and remainder of year updated forecast

(3) Numbers may not total due to rounding.

Q. Does this 2020 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 certain long-term opt-out customers return to a cost-of-service rate in 2020?

A. No. PGE does not assume that certain long-term opt-out customers return to cost of service in 2020. PGE assumes all long-term opt-out customers remain on direct access. PGE does assume that short-term (1-year) opt-out customers return to cost-of-service in 2020.

Q. If customers select a long-term opt-out program for 2020, will PGE adjust the load forecast?

A. Yes. PGE will adjust the 2020 cost-of-service load forecast accordingly, as specified in Schedule 125.

Q. Was the 2020 forecast developed using the same models used in Docket No. UE 335?

A. Yes. The same forecast models used in UE 335 were updated with recent actuals through January 2019, the February 2019 (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 2020 test year power cost forecast?

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

Table 4
Total System Load on Cycle Month at Meter
to Cost-of-Service Load on Calendar Month at Meter: 2020
(thousand MWh)

Total System Load (cycle month)	19,657
Add: Cycle to Calendar Month Difference	10
Total System Load (calendar month)	19,667
Less: Schedules 485/489	(2,082)
Cost-of-Service Meter Load	17,585

Numbers may not total due to rounding.

Q. What is the corresponding initial cost-of-service bus bar load forecast for 2020?

A. With the addition of line losses to Table 4, the initial bus bar load forecast for 2020 is 18,728.8 thousand MWh, or 2,132 MWa. This load is the basis for the hourly MONET load input data.

V. Comparison with 2019 NVPC Forecast

Q. Please restate your initial 2020 NVPC forecast.

A. The initial forecast is $422.0 million, or $22.53 per MWh.

Q. How does the 2020 forecast compare with the 2019 forecast utilized to develop power costs in Docket No. UE 335 and approved in Commission Order No. 18-405?

A. Based on PGE's final updated MONET run for the 2019 test year, the forecast was $361.5 million, or $19.60 per MWh. The initial 2020 NVPC forecast represents an increase of approximately $60.5 million over the 2019 final forecast, which is approximately $2.93 per MWh more than the final forecast for 2019.

Q. What are the primary factors that explain the increase in NVPC forecast for 2020 versus NVPC forecast for 2019 in UE 335?

A. Table 5 shows changes in NVPC by factor between 2019 and 2020.

Table 5
Forecast Power Cost Difference 2019 vs. 2018 ($ Million)

Factor	Effect ($M)
Hydro Cost and Performance	$ 1.0
Coal Cost and Performance	9.3
Gas Cost and Performance	(29.5)
Wind Cost and Performance	13.5
Contract and Market Purchases	58.4
Market Purchases for Load Change	10.9
Transmission	(3.1)
Total	**$ 60.5**

* *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 2020 versus the NVPC forecast for 2019 in Docket No. UE 335:

1. The increase of approximately $58.4 million related to contract and market purchases is due to:
   a. An increase of approximately $28.0 million in QF contract costs, as discussed in Section III (D) of this testimony, and
   b. An increase of approximately $30.4 million in costs related to market energy purchases due to higher on- and off-peak market forward power prices as of March 7, 2019, compared to the market forward curves modeled in the final 2019 NVPC forecast. The power and natural gas price spikes that the wholesale markets have seen during 2018 and 2019 have resulted in significant upward movement in forward prices throughout the western energy market.
2. The increase of approximately $13.5 million related to wind cost and performance is due to the expiration of PTC generation associated with phase 2 and phase 3 of PGE's Biglow Canyon Wind Farm. PTC generation associated with phase 2 of Biglow Canyon Wind Farm will begin to expire in 2019. All remaining PTC generation associated with phase 2 and phase 3 of PGE's Biglow Canyon Wind Farm will expire during August 2020.
3. The increase of approximately $9.3 million related to coal cost and performance is mostly due to PGE modeling maintenance derations at the Boardman generation plant to address 2020 supply constraints and mitigate the risk of coal remaining on site after the plant ceases operations. More details on Boardman operations are provided in Section III (C).

4. The increase of approximately $10.9 million in market purchases is due to a MWa load increase in 2020. As we discuss in Section IV of our testimony, our load forecast for cost-of-service energy is approximately 2,132 MWa, an increase of 27 MWa from the 2019 NVPC forecast in PGE's most recent NVPC proceeding in UE 335
5. The increase in the 2020 NVPC forecast is partially offset by a decrease to forward gas prices as the Enbridge pipeline in British Columbia is expected to return to normal operations by 2020, resulting in a reduction to the cost of our gas-fired resources by approximately $29.5 million (i.e., increased gas-fired resources output resulting in less market purchases). The reduction in forward gas prices is most significant at the Sumas gas hub with a 12% decrease in our initial 2020 NVPC forecast compared to the final 2019 NVPC forecast. Please note that gas and electric price curves modeled in PGE's initial 2020 NVPC forecast are as of March 7, 2019 and will be updated in subsequent NVPC updates.

Q. Does your 2020 NVPC forecast include a forecast of changes in coal contract costs for Colstrip?

A. No. PGE, as a co-owner[22] of the Colstrip generation plant in Montana, is currently negotiating the renewal of the existing coal supply contract with Westmoreland Coal Company, which will expire at the end of 2019. PGE will provide updates during this docket as the negotiation process continues. For purposes of this initial 2020 NVPC forecast, we assume the current contract price for coal during 2019.

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[22] The other co-owners are NorthWestern Energy, Puget Sound Electric, Avista Corp, and PacifiCorp.

VI. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including net variable power cost forecasting. The Financial Analysis group supports the Power Operations, Corporate Planning, and Rates & Regulatory Affairs groups within PGE.

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 OPUC Order No. 08-505

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.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Robert Macfarlane

April 1, 2019

Table of Contents

I. Introduction and Summary

Q. Please state your name and position.

A. My name is Robert Macfarlane. I am a Regulatory Consultant in the Pricing and Tariffs Department. My qualifications are listed in Section V.

Q. What is the purpose of your testimony?

A. This testimony describes the following:

- The estimated base rate price impacts from this filing anticipated to occur on January 1, 2020.
- 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 prices incorporating the final updates to Net Variable Power Costs (NVPC) on November 15, 2019. 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 $63.2 million increase in Schedule 125 prices, inclusive of changes in system usage charge prices?

A. Table 1 below summarizes the estimated 2020 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	3.0 %
Sch 32 Small Non-residential 30 kW or less	3.0 %
Sch 83 Non-residential 31-200 kW	3.8 %
Sch 85 Secondary 201-4,000 kW	4.8 %
Sch 85 Primary 201-4,000 kW	4.5 %
Sch 89 Primary Over 4,000 kW	4.8 %
Sch 89 Subtransmission Over 4,000 kW	4.3 %
Schedule 90 Over 100 MWa	5.2 %
COS Overall	3.5 %

Q. What other price changes do you expect to occur on January 1, 2020?

A. I anticipate changes to various supplemental schedules to occur on January 1, 2020:

1) The Schedule 102 Regional Power Act Credit will change because, presuming normal weather, the current amortization of the $2.4 million 2018 year-end balance owed to customers in the balancing account should be largely complete by the end of 2019.

2) For Schedule 105 Regulatory Adjustments, the current $2.1 million charge for residential pilot program amortizations will be set to zero and will be instead collected through Schedule 135. Other miscellaneous items may be amortized through Schedule 105.

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 reflect the revenue requirements of the energy storage projects included in PGE's proposals in UM 1856. However, it is too early to determine the amounts to recover.

5) Schedule 123 Decoupling will be a lower charge for Schedule 7 customers and a lower credit for Schedule 32 customers in 2020. PGE does not yet have enough information to develop estimates of the lost revenue recovery (LRRA) portion of Schedule 123 applicable to other nonresidential rate schedules.

6) Schedule 132 Federal Tax Reform Credit may have minor price changes due to applicable projected energy and remaining unamortized balance.

7) Schedule 135 Demand Response Cost Recovery Mechanism will increase due to increasing customer participation in applicable programs and cost recovery for the residential pricing pilots no longer collected through Schedule 105.

8) Schedule 137 Customer-Owned Solar Payment Option Cost Recovery Mechanism will decrease due to a balance owed to customers for previous years.

9) Schedule 143 Spent Fuel Adjustment will be set to a zero price or (if applicable) set to amortize a residual balance. This will result in an increase relative to the 2019 credit prices. The language in Schedule 143 will be modified so that any ongoing refunds from the United States Department of Energy are no longer refunded. Those credits are included in the Trojan Nuclear Decommissioning Trust (NDT) calculations and act to lower the charge embedded in base rates to customers for future decommissioning. The Trojan NDT annual accrual amount was reduced to $1.9 million reflecting these credits in PGE's 2019 general rate case (UE 335).

10) Schedule 145 Boardman Power Plant Decommissioning Adjustment will have price changes due to applicable projected energy and revenue requirement. Additional information regarding decommission 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 143 in addition to the changes in Schedule 125. Table 2 below summarizes the estimated 2020 cost of service (COS) base rate impacts for selected rate schedules.

Table 2
Estimated Base Rate Impacts Including Schedules 125, 123*, and 143

Schedule	Rate Impact
Sch 7 Residential	2.1 %
Sch 32 Small Non-residential 30 kW or less	4.1 %
Sch 83 Non-residential 31-200 kW	4.0 %
Sch 85 Secondary 201-4,000 kW	5.0 %
Sch 85 Primary 201-4,000 kW	4.7 %
Sch 89 Primary Over 4,000 kW	5.0 %
Sch 89 Subtransmission Over 4,000 kW	4.5 %
Schedule 90 Over 100 MWa	5.4 %
COS Overall	3.2 %

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

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 2020 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 2020 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 $63.2 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 2020. For 2020, I project NVPC revenues of $422.0 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 based 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 2020 Base Generation Revenues?

A. I present this calculation, which is simply the 2020 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. Why do you propose to change the System Usage and Distribution Prices for the various rate schedules?

A. 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 customers to all customers on the basis of equal cents per kWh. I then compare these allocations of 2020 Schedule 129 payments to the amount that is currently embedded in the System Usage and Distribution prices determined in UE 335. For Schedules 85, 89, 90 and their direct access equivalent schedules, the System Usage Charges are expected to decrease by 0.04 mills/kWh. For other schedules, the System Usage or Distribution Charges are also expected to decrease by 0.04 mills/kWh. PGE Exhibit 203 contains the detail behind 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 September 2019 for service commencing in 2020, 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. Do you have an exhibit that provides details regarding the prospective changes in production tax credits (PTC) applicable to Schedule 129 for the 2016 LTDA vintage?

A. Yes. PGE Exhibit 204 demonstrates the calculation of the unit change in PTCs by rate schedule.

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 two changes to the Annual Updates section of Schedule 125.

Q. Are the changes you propose substantive in nature or compliance in nature?

A. Both changes comply and are consistent with prior Commission orders.

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

A. I propose to remove the ability to update thermal plant operations and maintenance (O&M) between rate cases. In UE 215, PGE proposed language changes to Schedule 125 related to thermal plant O&M. The stipulating parties agreed that PGE will not update variable O&M between rate cases and the Commission approved that stipulation in Order No. 10-410. However, the proposed language was inadvertently retained and included in the compliance filing. I note that, although the language was included in Schedule 125 since 2011, PGE did not update thermal plant variable O&M between rate cases in the intervening years. Hence, PGE complied with the order. I propose to remove the language to be consistent with Order No. 10-410 and PGE's practice of not updating variable O&M between rate cases.

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

A. I propose to add language to allow updates for the deferred Qualifying Facilities (QF) differences in costs consistent with Commission Order No. 18-405. Exhibit 205 provides a redline of both changes to Schedule 125.

V. Qualifications of Witness

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

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

Q. Does this complete your testimony?

A. Yes.

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	Calculation of Unit Changes in PTCs
205	Schedule 125 Sheet 125-1 Redline

PORTLAND GENERAL ELECTRIC
Calculation of Schedule 125 Prices

Schedules	2020 Calendar COS Energy MWh	2020 Base Generation Revenues	Generation Allocation	2020 Base NVPC Revenues	Sch 125 Allocation	2020 NVPC Revenues	2020 Sch 125 Price mills/kWh	2020 Sch 125 Revenues	Cycle MWh	Cycle Revenues
Schedule 7	7,568,915	$488,154	47.31%	$170,755	$29,514	$200,269	3.90	$29,519	7,626,375	$29,743
Schedule 15	15,774	$773	0.07%	$270	$47	$317	2.96	$47	15,696	$46
Schedule 32	1,631,912	$95,336	9.24%	$33,324	$5,764	$39,088	3.53	$5,761	1,610,269	$5,684
Schedule 38	31,497	$1,696	0.16%	$593	$103	$696	3.26	$103	31,959	$104
Schedule 47	21,670	$1,537	0.15%	$538	$93	$631	4.29	$93	22,165	$95
Schedule 49	64,510	$4,560	0.44%	$1,595	$276	$1,871	4.27	$275	65,909	$281
Schedule 83	2,887,308	$168,275	16.31%	$58,872	$10,174	$69,046	3.52	$10,163	2,829,833	$9,961
Schedule 85-S	2,115,981	$120,072	11.64%	$41,537	$7,260	$48,796	3.43	$7,258	2,144,335	$7,355
Schedule 85-P	598,670	$33,127	3.21%	$11,548	$2,003	$13,551	3.35	$2,006	641,496	$2,149
Schedule 89-S	0	$0	0.00%	$0	$0	$0	3.18	$0	0	$0
Schedule 89-P	392,599	$20,254	1.96%	$7,059	$1,225	$8,284	3.12	$1,225	406,608	$1,269
Schedule 89-T	62,359	$3,248	0.31%	$1,106	$196	$1,303	3.15	$196	60,308	$190
Schedule 90	1,867,228	$92,287	8.94%	$33,423	$5,580	$39,003	2.99	$5,583	2,063,060	$6,169
Schedule 91	50,583	$2,478	0.24%	$866	$150	$1,016	2.96	$150	55,316	$164
Schedule 92	2,496	$128	0.01%	$45	$8	$52	3.09	$8	2,507	$8
TOTAL	17,311,501	$1,031,924	100.00%	$361,532	$62,390	$423,922		$62,386	17,575,836	$63,218

2020 NVPC ($000)	$421,988
2020 NVPC Revenues at Current Prices ($000)	$361,532
Change in NVPC	$60,456
Revenue Sensitive Adj. 3.2%	$1,935
Sch 125 Revenue Requirement	$62,390

PORTLAND GENERAL ELECTRIC
Calculation of Generation and NVPC Revenues

Schedule	2020 Calendar MWh	UE 335 Energy Price	2020 Base Energy Revenues	NVPC Price	2020 NVPC Revenues	2020 Cycle MWh	2020 Cycle to Calendar Ratio
Sch 7							
Block 1	6,306,176	63.29	$399,118	22.56	$142,267	6,354,049	1.007592
Block 2	1,262,740	70.51	$89,036	22.56	$28,487	1,272,326	1.007592
Sch 15	15,774	48.98	$773	17.13	$270	15,696	0.995055
Sch 32	1,631,912	58.42	$95,336	20.42	$33,324	1,610,269	0.986738
Sch 38							
On-peak	17,127	60.70	$1,040	18.84	$323	17,378	1.014651
Off-peak	14,370	45.70	$657	18.84	$271	14,581	1.014651
Sch 47	21,670	70.94	$1,537	24.82	$538	22,165	1.022840
Sch 49	64,510	70.68	$4,560	24.73	$1,595	65,909	1.021679
Sch 83							
On-peak	1,911,569	63.35	$121,098	20.39	$38,977	1,873,517	0.980094
Off-peak	975,739	48.35	$47,177	20.39	$19,895	956,316	0.980094
Sch 85-S							
On-peak	1,387,416	61.91	$85,895	19.63	$27,235	1,406,006	1.013400
Off-peak	728,566	46.91	$34,177	19.63	$14,302	738,328	1.013400
Sch 85-P							
On-peak	378,115	60.86	$23,012	19.29	$7,294	405,164	1.071536
Off-peak	220,554	45.86	$10,115	19.29	$4,254	236,332	1.071536
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	231,908	57.73	$13,388	17.98	$4,170	240,183	1.035683
Off-peak	160,691	42.73	$6,866	17.98	$2,889	166,425	1.035683
Sch 89-T							
On-peak	41,872	57.02	$2,388	17.74	$743	40,495	0.967113
Off-peak	20,487	42.02	$861	17.74	$363	19,813	0.967113
Sch 90							
On-peak	1,077,325	55.77	$60,082	17.90	$19,284	1,190,314	1.104879
Off-peak	789,903	40.77	$32,204	17.90	$14,139	872,747	1.104879
Sch 91/95	50,583	48.98	$2,478	17.13	$866	55,316	1.093569
Sch 92	2,496	51.09	$128	17.88	$45	2,507	1.004464
Totals	17,311,501		$1,031,924		$361,532	17,575,836	1.01527

UE 335 Fixed and NVPC Prices

Schedule	2020 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
2020

ALLOCATION OF TRANSITION ADJUSTMENT

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 7	7,626,375	40.1%	($8,430)	(1.11)
Schedule 15	15,696	0.1%	($17)	(1.11)
Schedule 32	1,610,269	8.5%	($1,780)	(1.11)
Schedule 38	31,959	0.2%	($35)	(1.11)
Schedule 47	22,165	0.1%	($25)	(1.11)
Schedule 49	65,909	0.3%	($73)	(1.11)
Schedule 83	2,829,833	14.9%	($3,128)	(1.11)
Schedule 85-S	2,528,316	13.3%	($2,795)	(1.11)
Schedule 85-P	854,238	4.5%	($944)	(1.11)
Schedule 89-S	11,172	0.1%	($12)	(1.11)
Schedule 89-P	1,034,228	5.4%	($1,143)	(1.11)
Schedule 89-T	247,852	1.3%	($274)	(1.11)
Schedule 90-P	2,063,060	10.9%	($2,281)	(1.11)
Schedules 91/95	55,316	0.3%	($61)	(1.11)
Schedule 92	2,507	0.0%	($3)	(1.11)
TOTAL	18,998,895	100.00%	($21,002)	(1.11)
		TARGET	($21,002)	

Change in Schedule 129 Transfer Payment Amount 2020

Schedules	Current mills/kWh	2020 mills/kWh	Change mills/kWh	Tariff Category
Schedule 7	(1.07)	(1.11)	(0.04)	Distribution
Schedule 15	(1.07)	(1.11)	(0.04)	Distribution
Schedule 32	(1.07)	(1.11)	(0.04)	Distribution
Schedule 38	(1.07)	(1.11)	(0.04)	Distribution
Schedule 47	(1.07)	(1.11)	(0.04)	Distribution
Schedule 49	(1.07)	(1.11)	(0.04)	Distribution
Schedule 83	(1.07)	(1.11)	(0.04)	System Usage
Schedule 85-S	(1.07)	(1.11)	(0.04)	System Usage
Schedule 85-P	(1.07)	(1.11)	(0.04)	System Usage
Schedule 89-S	(1.07)	(1.11)	(0.04)	System Usage
Schedule 89-P	(1.07)	(1.11)	(0.04)	System Usage
Schedule 89-T	(1.07)	(1.11)	(0.04)	System Usage
Schedule 90-P	(1.07)	(1.11)	(0.04)	System Usage
Schedules 91/95	(1.07)	(1.11)	(0.04)	Distribution
Schedule 92	(1.07)	(1.11)	(0.04)	Distribution
TOTAL				

Total Change in Distribution/System Usage Charge 2020

Schedules	Sys. Usage Current mills/kWh	Sch 129 Change mills/kWh	2020 Sys. Usage mills/kWh	Category
Schedule 7	2.18	(0.04)	2.14	Distribution
Schedule 15	10.44	(0.04)	10.40	Distribution
Schedule 32	1.87	(0.04)	1.83	Distribution
Schedule 38	2.34	(0.04)	2.30	Distribution
Schedule 47	4.15	(0.04)	4.11	Distribution
Schedule 49	2.71	(0.04)	2.67	Distribution
Schedule 83	6.99	(0.04)	6.95	System Usage
Schedule 85-S	0.97	(0.04)	0.93	System Usage
Schedule 85-P	0.93	(0.04)	0.89	System Usage
Schedule 89-S	1.02	(0.04)	0.98	System Usage
Schedule 89-P	0.99	(0.04)	0.95	System Usage
Schedule 89-T	0.97	(0.04)	0.93	System Usage
Schedule 90-P	0.54	(0.04)	0.50	System Usage
Schedules 91/95	2.68	(0.04)	2.64	Distribution
Schedule 92	1.10	(0.04)	1.06	Distribution
Schedule 515	9.14	(0.04)	9.10	Distribution
Schedule 532	0.32	(0.04)	0.28	Distribution
Schedule 538	0.91	(0.04)	0.87	Distribution
Schedule 549	0.84	(0.04)	0.80	Distribution
Schedule 583	5.44	(0.04)	5.40	System Usage
Schedule 485/585-S	(0.28)	(0.04)	(0.32)	System Usage
Schedule 485/585-P	(0.29)	(0.04)	(0.33)	System Usage
Schedule 489/589-S	(0.14)	(0.04)	(0.18)	System Usage
Schedule 489/589-P	(0.15)	(0.04)	(0.19)	System Usage
Schedule 489/589-T	(0.15)	(0.04)	(0.19)	System Usage
Schedule 490/590	(0.77)	(0.04)	(0.81)	System Usage
Schedule 491/495/591/595	1.38	(0.04)	1.34	Distribution
Schedule 492/592	(0.26)	(0.04)	(0.30)	Distribution

PORTLAND GENERAL ELECTRIC
Calculation of Unit Changes in Production Tax Credits Related to Senate Bill 1547

Schedules	2020 Calendar COS Energy MWh	Current PTCs mills/kWh	2020 PTC Revenues	PTC Allocation	2020 PTC Allocations	2020 PTC Price mills/kWh	Change in PTC Price mills/kWh	Cycle MWh	Cycle Revenues
Schedule 7	7,568,915	(3.01)	($22,782)	46.63%	($17,289)	(2.28)	0.73	7,626,375	($17,388)
Schedule 15	15,774	(2.43)	($38)	0.08%	($29)	(1.84)	0.59	15,696	($29)
Schedule 32	1,631,912	(2.79)	($4,553)	9.32%	($3,455)	(2.12)	0.67	1,610,269	($3,414)
Schedule 38	31,497	(2.59)	($82)	0.17%	($62)	(1.97)	0.62	31,959	($63)
Schedule 47	21,670	(3.27)	($71)	0.15%	($54)	(2.48)	0.79	22,165	($55)
Schedule 49	64,510	(3.25)	($210)	0.43%	($159)	(2.47)	0.78	65,909	($163)
Schedule 83	2,887,308	(2.77)	($7,998)	16.37%	($6,070)	(2.10)	0.67	2,829,833	($5,943)
Schedule 85-S	2,115,981	(2.68)	($5,671)	11.61%	($4,304)	(2.03)	0.65	2,144,335	($4,353)
Schedule 85-P	598,670	(2.65)	($1,586)	3.25%	($1,204)	(2.01)	0.64	641,496	($1,289)
Schedule 89-S	0	(2.53)	$0	0.00%	$0	(1.92)	0.61	0	$0
Schedule 89-P	392,599	(2.48)	($974)	1.99%	($739)	(1.88)	0.60	406,608	($764)
Schedule 89-T	62,359	(2.45)	($153)	0.31%	($116)	(1.86)	0.59	60,308	($112)
Schedule 90	1,867,228	(2.47)	($4,612)	9.44%	($3,500)	(1.87)	0.60	2,063,060	($3,858)
Schedule 91	50,583	(2.43)	($123)	0.25%	($93)	(1.84)	0.59	55,316	($102)
Schedule 92	2,496	(2.47)	($6)	0.01%	($5)	(1.87)	0.60	2,507	($5)
TOTAL	17,311,501		($48,859)	100.00%	($37,079)			17,575,836	($37,538)

2020 PTCs ($37,079)

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.
- Forward market prices for both gas and electricity.
- Projected loads.
- Contracts for the purchase or sale of power and fuel.
- Refunds or collections based on the deferred differences between actual and forecasted Qualifying Facility costs including cure period payments and interest on the balances.
- Emission control chemical costs.
- ~~Thermal plant variable operation and maintenance, including t~~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.

James F. Lobdell, Senior Vice President **on and after January 1, 2017**