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

February 29, 2024

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301
P.O. Box 1088
Salem, OR 97308-1088

Re: UE 436 – Portland General Electric Company's 2025 Annual Update Tariff

Dear Filing Center:

Portland General Electric Company (PGE) encloses for filing in the above reference matter the following: Direct Testimony of Erin Schwartz, Darrington Outama, Stefan Cristea (PGE/100) and PGE Exhibit 101.

Confidential workpapers in support of this filing contain protected information and are subject to the General Protective Order No. 23-132 noticed February 29, 2024. These will be posted to Huddle for those with appropriate access.

Please direct all formal correspondence, questions, and requests related to this filing to pge.opuc.filings@pgn.com.

Additionally, PGE requests that all data requests in this docket be submitted via Huddle and addressed to:

Jaki Ferchland
Portland General Electric Company
Manager, Rates & Regulatory Affairs
121 SW Salmon Street, 3WTC0306
Portland, OR 97204

The following are to receive notices and communications via the email service list:

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Sincerely,

/s/ Shay LaBray

Shay LaBray
Senior Director Regulatory Affairs &
Strategy
Resource & Regulatory Strategy

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 436

Net Variable Power Cost

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Erin Schwartz
Darrington Outama
Stefan Cristea

February 29, 2024

Table of Contents

I. Introduction

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

A. My name is Erin Schwartz. My position at PGE is Manager, Gross Margin and Power Cost Forecasting & Analysis.

My name is Darrington Outama. My position at PGE is Senior Director, Energy Supply.

My name is Stefan Cristea. My position at PGE is Regulatory Consultant, Regulatory Operations.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial forecast of PGE's 2025 Net Variable Power Costs (NVPC). We discuss proposed enhancements to MONET modeling, as well as other inputs. We compare our initial 2025 forecast with PGE's final 2024 NVPC forecast, inclusive of the impact of the Clearwater Wind Project, which will be included in customer prices during 2024, and discuss why the per-unit expected NVPC has increased by approximately $1.00 per MWh.[1]

Q. What is PGE's initial net variable power cost forecast for 2025?

A. Our initial 2025 NVPC forecast is $902.9 million, based on contracts and forward curves as of December 29, 2023. This initial 2025 NVPC forecast represents an increase of approximately $36.5 million compared to our 2024 NVPC forecast, inclusive of the Clearwater Wind Project, as provided in the MONET update submitted in PGE's Schedule

[1] The 2025 NVPC forecast per-unit cost is $42.6 per MWh which is approximately $1.0 per MWh more than the final 2024 NVPC forecast per unit cost of $41.6 per MWh, per the UE 427 December 8, 2023 update.

122-Renewable Resources Automatic Adjustment Clause filing (UE 427) on December 8, 2023.[2]

Q. What are the primary factors that explain the increase in NVPC forecast for 2025 versus the NVPC forecast for 2024?

A. The increase in NVPC is primarily driven by an expected increase in load compared to the final 2024 NVPC forecast, adjustments made to remove the reductions applied to the 2024 NVPC forecast pursuant to the NVPC stipulations adopted by the Commission through Order No. 23-386 in UE 416, contract updates, and other modeling updates that we discuss in this testimony. Table 1 included in Section IV lists the changes in NVPC by factor between 2024 and 2025.

Q. Is PGE filing a separate 2025 test year General Rate Case (GRC)?

A. Yes. Concurrently with this Annual Update Tariff (AUT) filing, we are filing a 2025 GRC (Docket No. UE 435). The NVPC portion of the 2025 GRC revenue requirement will be processed as part of this AUT filing. This AUT establishes the basis for recovering power costs and will be the 2025 forecast to which we compare the 2025 actual NVPC pursuant to the provisions of Schedule 126, which implements the Power Cost Adjustment Mechanism (PCAM).

Q. Is PGE proposing changes to Schedule 126?

A. Yes. PGE is submitting a separate advice filing with a request to modify the PCAM implemented through Schedule 126.

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

A. Yes. Public Utility Commission of Oregon (OPUC or Commission) Order No. 08-505

[2] The 2024 annualized NVPC forecast inclusive of the Clearwater Wind Project is $866.4 million. Schedule 122 prices, inclusive of Clearwater Wind Project benefits will be in effect starting with June 1, 2024.

adopted a list of MFRs for PGE to follow in AUT filings and General Rate Case (GRC) filings. The MFRs define the documents that PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 301 contains the list of required documents as approved by Commission Order No. 08-505. The MFRs required for our initial filing are included as part of our electronic work papers, with the remainder of the MFRs to be submitted within 15 days of this filing (i.e., March 14, 2024). The MFR documents are designated as "confidential" or "non-confidential."

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

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

- April 1 – Update parameters and forced outage rates; power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; California Carbon Allowance (CCA) forward price curve; Wheatridge renewable energy certificate (REC) monetization benefits, the Wheatridge facility performance report; and any errata corrections to our February 29 initial filing.
- July – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; CCA forward price curve; planned thermal and hydro maintenance outages; and loads.
- October – Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; CCA forward price curve; planned hydro maintenance outages; and loads.

- November – Two update filings: 1) update gas and electric forward curves; CCA forward price curve; final updates to power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; long-term customer opt-outs; Wheatridge REC monetization benefits; and 2) final update of gas and electric forward curves; final update to Qualifying Facilities commercial operation dates; and final update to the price of the power contract with Grant County.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have four sections:

- Section II – MONET Model
- Section III – MONET Updates and Modeling Changes
- Section IV – Comparison with 2024 NVPC Forecast
- Section V – Qualifications

II. MONET Model

Q. How does PGE forecast its NVPC for 2025?

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

Q. Please briefly describe MONET.

A. PGE developed 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 under "normal" conditions by economically dispatching plants and making market purchases and sales. To do this, the model employs the following data inputs:

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

- Transmission (wheeling) costs.
- Physical and financial electric contract purchases and sales.
- Forward market curves for gas and electric power purchases and sales.

Using these data inputs, MONET simulates the dispatch of PGE resources to meet its customer load forecast 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 operate in one of various stages – maximum availability, ramping up to 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 NVPC to Federal Energy Regulatory Commission (FERC) accounts 447, 501, 547, 555, and 565. As in the 2024 NVPC forecast, we include certain variable chemical costs, lubricating oil costs, and forecasted federal production tax credits (PTCs). We exclude some variable power costs, such as certain variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. Based on prior Commission decisions, certain fixed costs, such as excise taxes and transportation charges, are also 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, transmission, natural gas, fuel, and associated financial instruments.

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

A. Yes. The MFRs provide detailed work papers supporting the inputs to MONET used to develop our initial forecast of 2025 NVPC.

III. MONET Updates and Modeling Changes

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

A. Yes. We include parameter revisions, as well as modeling enhancements and updates.

Q. What MONET updates do you include in this AUT filing?

A. In this initial filing we include many of the updates allowed under Schedule 125. Additional items requiring actual 2023 data, or for which updated data were not available in a timely manner for this initial NVPC filing, will be updated in our April 1 filing. For example, among those items is the update to thermal forced outage rates, wind generation forecast, or certain inputs to thermal plant parameters. We will continue to update several of the items included under Schedule 125 as this docket proceeds.

Q. What modeling enhancements and new items do you include in this AUT filing?

A. We include thermal plant parameter updates, modeling enhancements, and new items. In this testimony we discuss the following updates and modeling enhancements:

- Section III.A: Ancillary Services Modeling
- Section III.B: Hydro Generation Forecast Methodology
- Section III.C: New Resources: Battery Energy Storage Systems
- Section III.D: Other Items:
    1. Capacity Planning
    2. MONET Administrative Changes
    3. Hydro Production Tax Credits
    4. Forthcoming Updates

Q. What is the net effect on PGE's initial 2024 NVPC forecast of the updates and modeling enhancements included in the initial MONET step-log?

A. The net effect of the updates and modeling enhancements reflected in the initial MONET step-log, inclusive of the new battery resources, in PGE's initial 2025 NVPC forecast is *de minimis* compared to the base 2025 NVPC forecast.

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

A. We use the 2025 retail load forecast described in PGE's 2025 GRC filing, Exhibit 700. Our forecast is approximately 21,212 thousand MWh of cost-of-service energy, or approximately 2,421.5 MWa, an increase of 42 MWa from the final 2024 test year forecast (Docket No. UE 416).

A. Ancillary Services Modeling

Q. Please briefly explain PGE's method for meeting PGE's ancillary service needs in MONET.

A. Ancillary services represent a set of tools utilized by grid operators to keep the bulk power system in balance between supply and demand in real time. MONET's ancillary service modeling includes regulating margin reserves, load following reserves, contingency spin and non-spin reserves, frequency reserves, and reserves to meet day-ahead and hour-ahead forecast errors (DAFE/HAFE). The MONET logic allocates ancillary services to PGE hydro and thermal resources while optimizing PGE's Mid-C projects. A detailed description of the modeling and information regarding which resources can meet specific reserve requirements is provided in the MFR's whitepapers, Volume 8 – Ancillary Services.

Q. What update has PGE made to the ancillary service modeling in MONET for this filing?

A. We have made an update to the modeling of PGE's contingency reserve obligation (CRO).

Q. Please describe the CRO enhancement.

A. PGE's Balancing Authority Area, in alignment with North American Electric Reliability Corporation (NERC) reliability standards regulation, no longer requires PGE's Power Operations to meet 50% of CRO with spinning reserves. Accordingly, we removed this requirement from the MONET ancillary services logic. Additional detail regarding this update is provided in the MFRs, Volume 9 – Enhancements and New Items.

Q. What is the NVPC impact associated with this update?

A. Updating CRO to align with current NERC standards results in a $1.9 million reduction to the 2025 NVPC forecast.

B. Hydro Generation Forecast

Q. Please summarize your proposal regarding the hydro generation forecast modeling.

A. We propose to discontinue the use of the Northwest Power Pool (NWPP) 80-year regulation study called Headwater Benefits Study (HB Study) and instead, use the most recent 10 years as basis for the forecast, adjusted to also incorporate known and verifiable climatological indicators for the upcoming water year. The updated method will use more recent and relevant hydro data to support our hydro generation forecast.

Q. Please briefly describe the NWPP HB Study.

A. The study is based on a regulation model whose objective function is to maximize the firm energy load-carrying capability of the Northwest system. This model considers the loads and thermal resources of regional entities, as well as hydro resources. The model produces a simulated regulation of 80 water years under historical stream flows, which was then used, with a set of adjustments, to develop the average hydro energy inputs to MONET.

Q. Did you identify issues with the model received from NWPP?

A. Yes. The regulation model used for the HB Study includes Fortran programming code that was developed in the 1950s, making the model complicated to update and use. The model can be run in two modes, 1) continuous mode,[3] and 2) refill mode.[4] The NWPP provides the model results using the refill mode. However, for PGE's purposes the model needs to run in continuous mode, requiring PGE to re-run the model after receiving it. This model re-run presents significant challenges given the language the underlying code is written in, and it is extremely time consuming.

Q. Are there other logistical issues with the NWPP regulation model?

A. Yes. Currently, PGE is not aware of a designated person at the NWPP to update and run the hydro regulation model for the HB Study. Additionally, even with a designated person at NWPP, the antiquated programing code makes the model very complicated and prone to errors.

Q. Aside from the technical and logistical issues with the model, is it still a reliable model to forecast hydro generation for rate making purposes?

A. No. Aside from all the HB study model technical and logistical issues described above, due primarily to the 80-year time frame, the NWPP HB Study is no longer an appropriate tool to forecast hydro generation. Use of an 80-year time frame does not place sufficient weight on the hydro conditions experienced in more recent years, which are more reflective of expected hydro conditions in the test year. In more recent years there have been climate change related

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[3] The continuous mode takes the water reservoir level at the end of each water year and starts the new water year with the reservoir at that level.

[4] The refill mode assumes that water reservoirs refill before the start of each new water year, irrespective of the ending water level in the reservoir for the previous year. This approach artificially creates water to ensure the reservoir is full at the start of each water year.

events such as extreme heat waves or persistent droughts that have impacted regional water flows and hydro generation and are more reflective of forecasted hydro moving forward.

Q. Do you propose a modeling update to the hydro energy forecast in the 2025 NVPC forecast?

A. Yes. We propose to forecast hydro generation using a combination of: 1) actual observed hydro generation and 2) hydro conditions expected for the upcoming water year.[5]

Q. What data do you propose using for the historical hydro generation?

A. We propose using a rolling average of actual generation observed in the most recent ten full years (i.e., 2013-2022) at PGE hydro resources and Mid-Columbia hydro projects, adjusted for known outages that reduced the plant generation.[6] For the purposes of the hydro energy forecast modeling we use the same monthly data that was reported to the Energy Information Administration (EIA).[7] Using actual hydro generation data from the last ten-years better reflects current hydro conditions and provides for a more reliable and accurate starting estimate for the test period, while also still recognizing the longer-term patterns of regional water flows

Q. Please discuss the additional adjustment to the hydro forecast associated with climatological indicators for the upcoming water year.

A. We propose to incorporate an updated hydro forecast no later than the first November MONET update. This forecast is intended to capture the expected impacts of known and verifiable indicators for the upcoming water year, as published by climatological authorities or agencies. These indicators can be reservoir levels, soil moisture/saturation, seasonal and

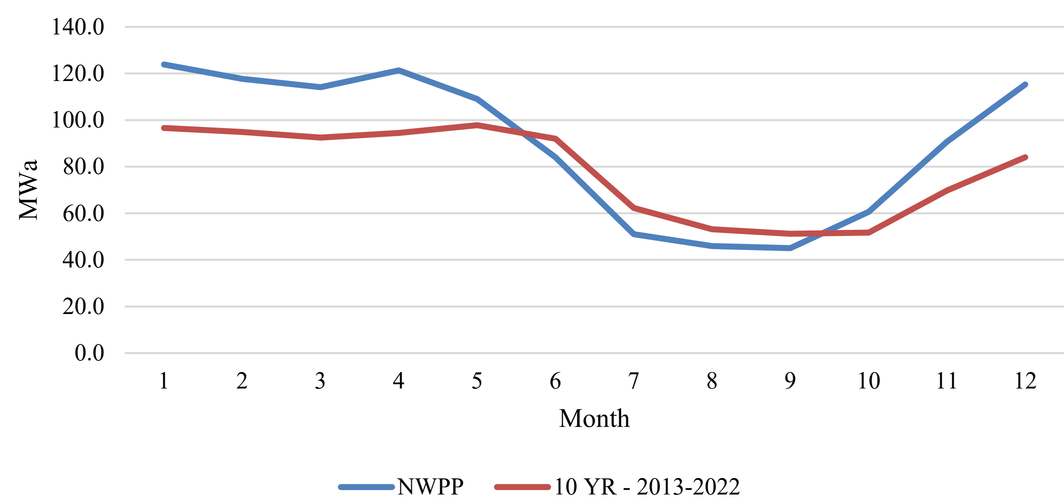
[5] The water year runs between October 1 and September 30 of the following year.
[6] There are hydro outages that do not impact plant generation because, as the outages occur when the water flow is low enough, the remaining hydro units can generate with the water available.
[7] PGE is federally required to report hydro generation data by plant and month to EIA.

monthly run-off forecasts, and/or the forecasted El-Nino Southern Oscillation (ENSO) signal. In the first November MONET update we will provide detailed information regarding the climatological indicators, the source of the information, the expected impact to the water year, and the associated adjustment to the hydro forecast.

Q. For the initial filing, how does hydro generation compare between the HB 80-year study that was last updated in the 2019 GRC and the updated hydro forecast methodology?

A. Using actual hydro generation from the most recent full ten years results in a change to the shaping of monthly hydro generation, a slight reduction in total hydro generation from our West Side Hydro and Pelton-Round Butte resources, and an increase in Mid-C index-priced energy associated with our Mid-C contracts. Figures 1 through 3 below provide the comparison between NWPP's 80-year study and the 10-year monthly average generation for PGE's West Side Hydro projects,[8] the Pelton-Round Butte hydro facility, and the Mid-Columbia hydro projects.[9] The underlying detailed data is provided in the MFRs.

Figure 1
2025 NVPC Initial Filing: West Side Hydro (MWa)



[8] Includes Oak Grove, North Fork, Faraday, River Mill, and T.W. Sullivan Hydro projects.
[9] Includes Priest Rapids, Rock Island, Rocky Reach, Wanapum, and Wells Hydro projects.

Figure 2
2025 NVPC Initial Filing: Pelton Round Butte (MWa)

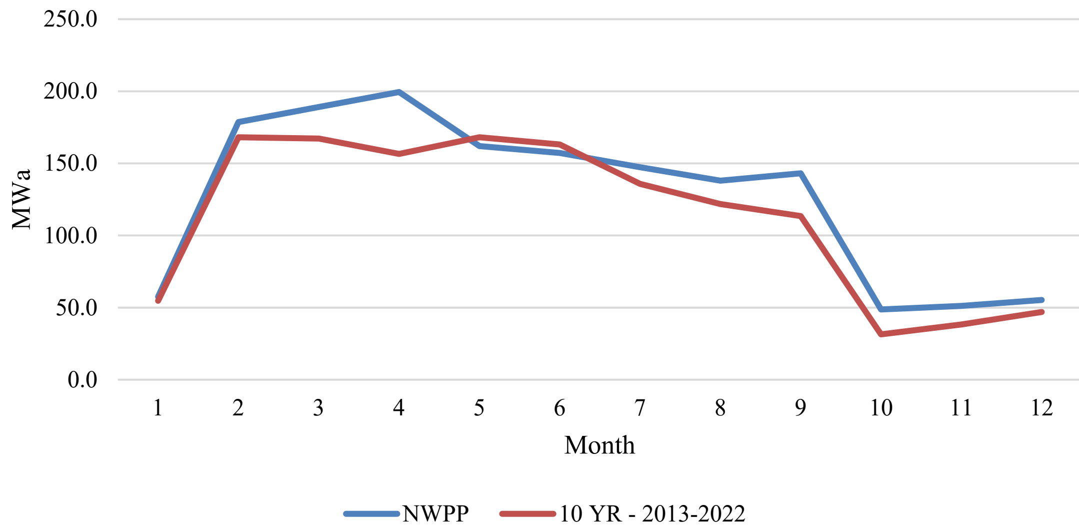
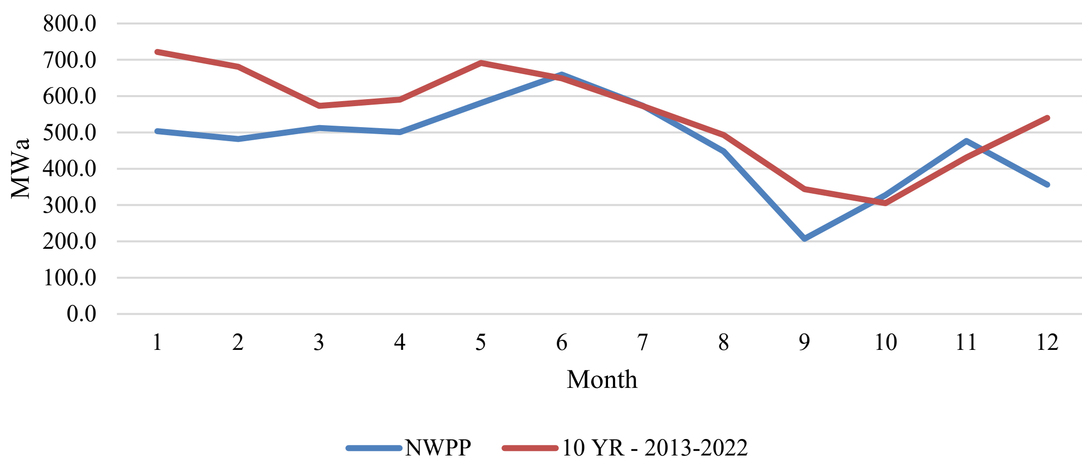


Figure 3
2025 NVPC Initial Filing: Mid-Columbia Hydro (MWa)



Q. What is the NVPC impact associated with updating the hydro generation forecast modeling?

A. Updating the hydro generation forecast modeling results in a 2025 NVPC forecast increase of approximately $11.8 million for the 2025 AUT initial filing. As discussed above, we will adjust the forecast to incorporate climatological indicators for the upcoming water year no later than the first November MONET update.

C. New Resources: Battery Energy Storage Systems

Q. Has PGE added any new resources for the 2025 test year?

A. Yes. We added two PGE-owned battery energy storage system (BESS) projects. Additionally, PGE executed a storage capacity agreement associated with one additional BESS. We provide details below.

Q. Please briefly describe the BESS's that PGE is adding to its 2025 resource portfolio.

A. The BESS's included in PGE's 2025 resource portfolio are added pursuant to the 2021 All-Source Request for Proposal (RFP) solicitation process (Docket No. UM 2166) which aligned with PGE's action plan outlined in the 2019 Integrated Resource Plan. PGE Exhibit 500 (Production) submitted with our 2025 GRC provides extensive detail regarding the competitive solicitation and acquisition process and descriptions of the PGE-owned Constable and Seaside BESS resources. In addition to the two owned BESS's, PGE is also adding a 20-year storage capacity agreement for another BESS, with an effective date of January 1, 2025. Consequently, PGE's 2025 resource portfolio will include:

- PGE-owned Constable BESS with a capacity of 75 MW/4 hours (300 MWh) and COD expected in late 2024 or early 2025.
- PGE-owned Seaside BESS with a capacity of 200 MW/4 hours (800 MWh) and COD expected in Q2 2025.
- Storage Capacity Agreement for the Troutdale BESS with a capacity of 200 MW/4 hours PPA (800 MWh) and a contract start date of January 1, 2025.

Q. When is PGE requesting that Constable and Seaside BESSs be included in customer prices?

A. As part of our 2025 GRC filing, we are requesting that prices recovering the revenue requirements associated with the two owned BESSs, inclusive of NVPC, become effective commensurate with the execution of an attestation by a PGE Officer that the project has been placed in service. Consequently, because the two owned BESSs will be tracked in customer prices in accordance with their in-service date, PGE's 2025 initial filing revenue requirement as summarized in PGE's 2025 GRC filing (Docket No. UE 435), Exhibit 200, Table 1, does not include the BESSs costs or NVPC benefits.[10]

Q. What are the power cost benefits expected to be achieved through the dispatch of the aforementioned BESSs?

A. The BESSs are expected to provide benefits to customers through energy shaping, helping to meet peak load, and responding to PGE system reserve requirements.

Q. Please describe how BESSs provide benefits associated with energy shaping and optimization.

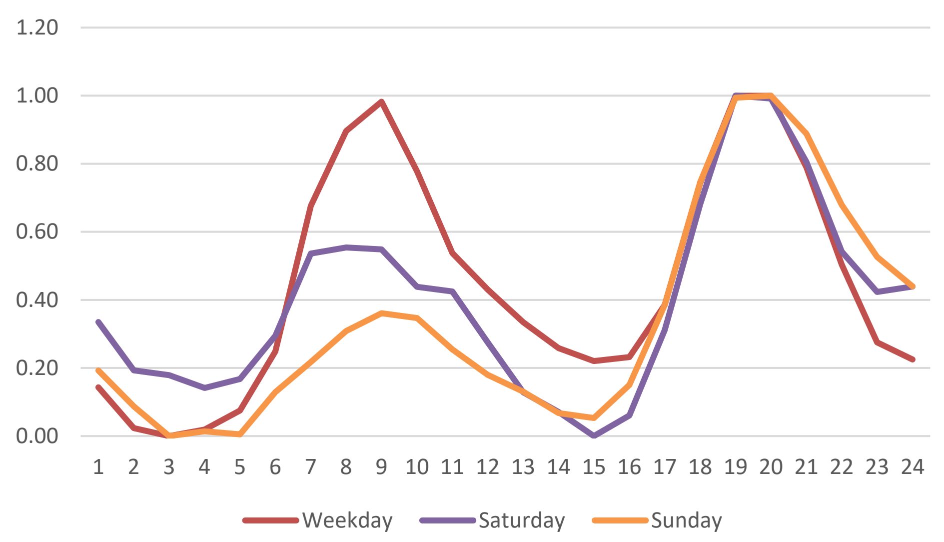
A. PGE is modeling the BESS cycles to maximize the daily battery dispatch benefits by charging when the hourly Mid-C prices in MONET are low and discharging when they are high. Because summer and winter months have different price profiles, PGE models the BESS's operation accordingly. Additionally, PGE applies an operational efficiency factor based on actual operational data from CAISO energy storage fleet. Please review the corresponding MFR for full details.

[10] The 2025 NVPC forecast after removing annualized NVPC benefits associated with Constable and Seaside BESSs and reflected in the revenue requirement summary presented in PGE Exhibit 200, Table 1, is $923.0 million.

During winter months, the hourly Mid-C price profile in MONET has a dual peak (one in the late morning and one in the evening). To optimize for the winter dual price peak, PGE models the BESS's operation as provided below, while limiting the battery cycle to 6 hours of maximum discharge (or 1.5 cycles):

- Charge for 2-4 hours in early morning
- Discharge for 2-4 hours during morning peak
- Charge for 2-4 hours mid-day
- Discharge for 2-4 hours in evening peak.

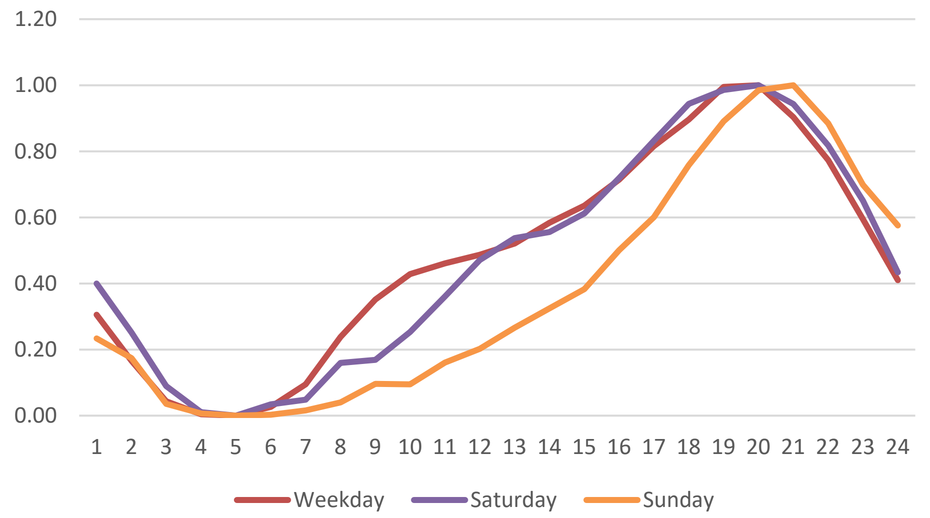
Figure 4
Winter Price Profile



During summer months, PGE models the BESS's operation to be a single cycle, as follows:

- Charge for 4 hours in early morning
- Discharge for 4 hours during the evening peak.

Figure 5
Summer Price Profile



PGE does not apply any energy shaping during transition months when the price profile for the modeled days are flat and there is no optimization to be achieved. Since the battery has limited cycles, they are first prioritized to months with the largest differences between charge and discharge prices and supporting ancillary services. If there are cycles remaining after optimizing for Winter, Summer, and Ancillary services; the remaining cycles are used in transition months from highest value to lowest value until all 365 cycles have been used.

Q. Please discuss the operational efficiency derate you applied.

A. PGE acknowledges that the batteries modeled here have yet to achieve commercial operations and the model is currently lacking operational experience as a basis. Therefore, PGE has leveraged CAISO battery fleet operations data to model an operational efficiency factor in the initial AUT filing. These factors are applied on a monthly basis using two years of historical data and calculations performed by an independent market analytics vendor. We provide additional detail in MFRs.

Q. Please discuss at a high level how BESSs will support PGE's ancillary service needs.

A. PGE models using BESS cycles to respond to the errors between the hour-ahead forecasts and 5-minutes actuals (or HAFE). After cycling to optimize market transactions during the most valuable months, there are battery dispatch cycles remaining available for providing ancillary services. PGE's ancillary services modeling prioritizes hydro resources for meeting ancillary service requirements before BESS. BESSs are then modeled to meet any remaining ancillary services needs in hours when there is unmet reserve requirements.

Q. What is the net power cost benefit associated with three new BESSs included in the 2025 NVPC forecast?

A. The forecast power cost benefit associated with the three BESSs, net of the fees associated with the Troutdale BESS, is approximately $8.8 million for 2025.

D. Other Items

1. Capacity Planning

Q. Did you discuss capacity planning in prior NVPC forecast filings?

A. Yes. We described in detail in our 2022, 2023, and 2024 AUTs/GRCs the energy resource capacity landscape changes seen in the last two decades within the Western Electricity Coordinating Council (WECC) including the Northwest Power Pool (NWPP) footprint, and how these changes impact PGE's ability to meet customer peak loads with market purchases.[11]

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

A. First, the reduction in regional firm and dispatchable resources is causing a regional capacity

[11] Docket No. UE 391, PGE Exhibit 100, Section III.A; Docket No., UE 402, PGE Exhibit 100, Section III.A; Docket No. UE 416, PGE Exhibit 300, Section III.B.

shortage. This manifests in the form of extreme price volatility and increases the number of scarcity price events during weather driven load excursions or other market events. This phenomenon has created a gap between how PGE dispatches its thermal plants in actual operations versus the economic dispatch in the MONET model. Second, even during times of relatively normal load conditions, the shift from firm and dispatchable resources to variable energy resources (i.e., wind and solar resources) has resulted in increased price volatility as observed in the day-ahead energy market due to wind and solar generation uncertainty.

Q. What options does PGE have to mitigate the capacity shortage issue in the short-term?

A. There could be two potential approaches. One possible strategy is for PGE to enter into structured capacity agreements to help mitigate the exposure to weather driven load excursions and maintain load serving reliability.

Q. Has PGE included a new capacity contract within its initial 2025 NVPC forecast?

A. No. However, PGE's Commercial Initiatives group is exploring structured products that would be effective in 2025. Should PGE execute new capacity contracts we will notify parties and provide the agreements as soon as they are finalized.

Q. What is a second possible strategy?

A. A second possible strategy would be to deliberately withhold a portion of the marginal resource, i.e., Beaver or PW-II capacity from the MONET economic dispatch similar to how planned outages are modeled. For example, PGE would add a secondary planned maintenance outage for three gas turbines at Beaver and three PW2 engines, withholding approximately 200 MW capacity for one week each month during the period between July 1 and September 30. This approach would withhold this generator's capacity from the deterministic economic dispatch in the MONET logic thereby simulating the actions and the frequency that PGE would take operationally to ensure reliability.

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

A. Not at this time. However, should PGE propose a methodology to reflect the cost of capacity planning, we will model this in our April 1 MONET update, and we will provide more information to parties through supporting MFR documentation.

2. MONET Administrative Changes

Q. What MONET administrative change did you make?

A. We update "hydro spill" nomenclature in MONET to "Unmet Ancillary Services Capacity".

Q. Why do you update the "hydro spill" MONET nomenclature to "Unmet Ancillary Service Capacity"?

A. We update the nomenclature to ensure clarity that in MONET, "hydro spill" is not equivalent to actual spill of hydro energy. Instead, it represents a modeling approach used to estimate the costs associated with unmet ancillary service capacity that is resolved through wholesale market power purchases of equal generation quantity at the market price. The unmet ancillary service capacity represents the additional reserve capacity that is needed when PGE's reserve quantity requirement is greater than flexible capacity available on PGE's resources. Instances when there is unmet ancillary service capacity occur in both the MONET AS modeling and in PGE's actual power operations.

3. Hydro Production Tax Credits (PTC)

Q. How do you currently model hydro PTCs in MONET?

A. Hydro PTCs are currently based on incremental energy eligible for PTC awards which is calculated as fixed MWh.

Q. How do you update the hydro PTC calculation?

A. We update the PTC calculation to align with FERC's determination of PTC qualifying hydro generation. Specifically, qualifying hydro generation is determined from the incremental generation that results from efficiency improvement or additions of capacity compared to an annual power production baseline over a given flow period. The PTC qualifying generation is then represented as a percentage increase of the annual average generation.

Q. What is the percentage generation at PGE's hydro units that qualifies for PTCs?

A. Consistent with PGE's request for certification associated with the Faraday hydro plant, PGE expects that the average annual generation at Faraday will increase by 22.2% pursuant to the Faraday Repowering Project. Consequently, 22.2% of Faraday generation is expected to qualify for PTC awards. Additionally, per FERC determination, 2.07% of Harriet Powerhouse generation and 3.45% of Timothy Powerhouse generation qualify for PTCs.

Q. What impact of this update on the 2025 NVPC forecast?

A. Updating the hydro PTC modeling reduces the 2025 NVPC forecast by approximately $1.2 million.

4. Forthcoming Updates

Q. Does PGE expect to update any items in future filings in this proceeding?

A. Yes. We expect to update plant parameters and forced outage rates; power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; wind resource energy forecasts; load forecast; historical COB trading data; CCA forward price curve; Wheatridge REC monetization benefits, wind and hydro PTC rates; and make any errata corrections to this initial filing in the April 1 filing. This is standard practice for NVPC filings during a GRC year.

IV. Comparison with 2024 NVPC Forecast

Q. Please restate PGE's initial 2025 NVPC forecast.

A. The initial forecast is $902.9 million.

Q. How does this 2025 NVPC forecast compare with the 2024 final NVPC forecast inclusive of the Clearwater Wind Project, as updated in PGE's RAAC filing in UE 427?

A. Based on PGE's updated MONET run submitted in UE 427, the NVPC forecast was $866.4 million, or $41.6 per MWh. The initial 2025 forecast is $902.9 million, or $42.6 per MWh, which is approximately $1.0 per MWh more than the final forecast for 2024.

Q. What are the primary factors that explain the increase in NVPC forecast for 2025 versus the NVPC forecast for 2024?

A. Table 1 below lists changes in NVPC by factor between 2024 and 2025.

Table 1
Forecast Power Cost Difference 2024 vs. 2025 ($ Millions)

Factor	Effect ($M)
Hydro Cost and Performance	$ (22.0)
Coal Cost and Performance	0.7
Gas Cost and Performance	(22.4)
2024 GRC Stipulation	14.5
VER and Owned Battery Cost and Performance	10.8
Contract and Market Purchases	37.8
Market Purchases for Load Increase	27.6
Transmission	(10.5)
Total	**$ 36.5**

* *Numbers may not total due to rounding.*

The primary factors contributing to the increase in NVPC include: 1) increased costs associated with adding new storage capacity agreement and a reduction in net market sales, 2) increased market purchase volumes and costs due to an expected increase in customer loads, and 3) increased costs associated with removing the NVPC reduction applied to the 2024 NVPC forecast pursuant to the stipulation adopted by the Commission through Order No. 23-

386. The increase in costs is partially offset by reduced costs associated with hydro and gas plants generation and a decrease in transmission costs.

Q. Please provide some detail regarding the NVPC reduction associated with hydro and gas operations.

A. The NVPC reduction associated with PGE's hydro operations is primarily related to: 1) increased expected total output from hydro contracts at a reduced price per MWh compared to the final 2024 NVPC forecast which contributes to an increase in forward market sales and benefits; and 2) a reduction in unmet ancillary capacity needs pursuant to the addition of the battery storage systems described in section III.C. The reduction in unmet ancillary capacity removes the need for market transactions to fill this need, resulting in a decrease to forecast power costs. The power cost reduction more than outweighs the increase associated with updating the hydro forecast methodology described in Section III.B. Therefore, while the change in hydro forecast methodology results in a power cost increase, that increase is more than offset by the factors described here.

The power cost reduction associated with gas plant operations is related to an increase in expected gas plant generation that benefits power costs due to an associated reduction in market purchases or an increase in market sales, depending on how the hourly MONET economically dispatches our portfolio.

V. Qualifications

Q. Ms. Schwartz, please describe your qualifications.

A. I received a Bachelor of Arts degree in Accounting from the University of Oregon in 2013. I have worked at PGE in various finance and accounting roles since May 2019. Currently, I manage the MONET modeling team in addition to a team of accountants. Prior to PGE, most of my experience was in the audit practice of a Big Four accounting firm. I am a Certified Public Accountant in the state of Oregon.

Q. Mr. Outama, please describe your qualifications.

A. I received a Bachelor of Science degree in Accounting from the University of Washington in 1996. I have over 25 years of experience with PGE working in accounting, financial planning, risk management, structuring and origination, and power operations. I have been involved in originating and pricing of custom products, asset acquisitions, as well as ad hoc project management including the 2012 Request for Proposals on behalf of PGE's customers. My current position is Senior Director Energy Supply. Prior to this I held positions as General Manager of Power Operations, Director of Financial Forecasting & Planning and Manager, Origination, Structuring and Fundamental Analysis.

Q. Mr. Cristea, please describe your qualifications.

A. I received a Bachelor of Arts degree in Regulatory Economics from the University of Calgary, Alberta, Canada. I have been employed at PGE in the Rates and Regulatory Affairs department since 2016. I have served as a witness to or lead regulatory analyst for numerous PGE ratemaking, rulemaking, and policy regulatory proceedings such as general rate cases, annual power cost updates, and power cost adjustment mechanism. Previously, I worked as an Operations Coordinator for Enterprise Holdings in Calgary, Alberta, Canada, overseeing the operations of approximately 50 car-rental offices. Prior to that, I owned and managed a construction business in France.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
101	List of MFRs per Commission 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

Supporting Documents and Work Papers for the Following

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

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

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

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

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

       Electric Physical Contracts
       Electric Financial Contracts
       Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

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

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

<u>Historical Operating Data</u>

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

Update Filings

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