CASE: UE 394
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

OVERVIEW

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Matt Muldoon. I am a Manager employed in the Rates, Finance, and Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Stipulating Parties/102.

Q. What is the purpose of your testimony?

A. I provide an overview of Staff's Opening Testimony regarding the Portland General Electric Company (Portland General Electric, PGE, or Company) request for a general rate revision, docketed as Docket No. UE 394. I introduce Staff witness respective assignments regarding issues identified by Staff to date. Please note that Staff reserves the right to change recommendations and issues after reviewing testimony and analysis by other parties in this docket. Additionally, I highlight some key topics and provide some context regarding the Cost of Capital partial stipulation previously executed in this docket.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Note: Light blue text hyperlinks to points within this testimony.
Dark blue text hyperlinks to points in other Staff's testimony.

OVERVIEW OF STAFF'S OPENING TESTIMONY

Q. What issues were examined by Staff in this Opening Testimony?

A. Staff reviewed the issues provided in Table 1 below:

Table 1 – Issues Examined by Staff

	Staff		Topic
100	Muldoon	1	Overview
200	Fox	1	Summary of Revenue Requirement
		2	Overall Rate Base
		3	Income Taxes
		4	Incentive Payroll Taxes
		5	Oregon Corporate Activity Tax (CAT)
		6	Beaver Modernization
		7	Upgrade of Excitation System
300	Cohen	1	Compensation
		2	Full Time Equivalents (FTE)
		3	Uncollectible Expense
		4	Customer Account Expenses
		5	Advertising Expenses
		6	Human Resources (HR) Employee Support Reductions
		7	Compensation
400	Scala	1	Customer Services, and Operations and Maintenance (O&M) - Non Labor (NL)
		2	Decoupling
		3	Lighting
		4	Fee Free Bank Card (FFBC) Payment Option
		5	HB 2475 Implementation
500	Fjeldheim	1	Administrative and General (A&G) Expenses NL
		2	Information Technology (IT)
		3	Security (Physical and Cyber)
		4	Cash Working Capital (CWC)
		5	Employee Health & Life Insurance
		6	Other Insurance
		7	Amortization Expense
		8	Colstrip Decommissioning Date
		9	Trojan Nuclear Decommissioning Trust
600	Dlouhy	1	Pension and Post-Retirement Medical Expense
		2	Finance and Accounting Expenses
		3	Wildfire Mitigation and Vegetation Management

		4	Enterprise Risk Management August 2020 Trading Losses
		5	Monetary Trading Losses Taken Out of Rates
		6	Personnel Changes Following the Trading Losses
		7	Risk Practice Changes Following the Trading Losses
700	Hanhan	1	Transmission Projects, Including Integrated Operations Center (IOC)
		2	FERC Rate Case and Other Revenues
		3	Reclassification Update
800	*Sayen	1	Advanced Distribution Management System (ADMS) Capital
		2	ADMS O&M
		3	Distribution Projects
900	Gibbens	1	Load Forecast
		2	Direct Access Related Charges
		3	Covid-19 Impacts Summary
1000	Enright	1	Fuel Stock
		2	Faraday Repowering Project
		3	Affiliated Interest (AI) Transactions
1100	Moore	1	Directors and Officers (D&O) Insurance
		2	Directors Fees and Expenses
		3	Generation O&M NL
		4	Transmission and Distribution (T&D) O&M NL
		5	Non-Fuel Materials and Supplies
		6	Miscellaneous Deferrals
		7	Major Maintenance Accrual
1200	Rossow	1	Memberships
		2	Meals and Entertainment, and Miscellaneous O&M Expense
1300	Zarate	1	Losses or Gains on Sales of Utility Property
		2	Other Revenue
1400	St. Brown	1	Level III Outage Mechanism
		2	Marginal Cost of Service, Rate Spread and Rate Design
1500	Peng	1	Depreciation Expense
		2	Depreciation Reserve
		3	Allowance for Funds Used During Construction (AFUDC)
1600	Kim	1	Research and Development (R&D)
1700	Shierman	1	Transportation Electrification (TE) and Schedule 150
		2	Line Extension Allowances for TE Projects
		3	Recovery on TE Programs the Commission Has Approved
		4	Recovery on TE Programs the Commission Has Not Approved
1800	Storm	1	UM 2119 Deferral of Boardman-related costs
1900	Anderson	1	Colstrip Schedule 146 Net Plant Balance

2000	Batmale	1	Background to TE, and Flexible Load and Distribution Planning (FLDP)
		2	Assessment of TE and FLDP
2100	*Sayen	1	Online Marketplace

*First of two Sayen Testimonies.
*Second of two Sayen Testimonies.

PARTIAL STIPULATION RESOLVING COST OF CAPITAL

Q. The parties to this case have executed a stipulation regarding Cost of Capital issues. Did Staff analyze all Cost of Capital components prior to entering into the stipulation?

A. Yes. Staff economists Curtis Dlouhy and Moya Enright performed Staff's usual and customary analysis regarding each component of Cost of Capital, which include Return on Equity (ROE), Capital Structure, and Cost of Long-Term Debt as well as overall Return on Equity (ROE), inclusive of all equity flotation expense. Because PGE, Staff, Oregon Citizens' Utility Board, Alliance of Western Energy Consumers, Fred Meyer Stores and Quality Food Centers, and Walmart, Inc. (collectively, the Stipulating Parties) reached a resolution on all components of Cost of Capital, Staff's position is described in Stipulating Parties' Joint Testimony in Support of a Partial Stipulation Resolving Cost of Capital (Joint Testimony).[1]

The Partial Stipulation is provided as Exhibit Stipulating Parties/101 to the Joint Testimony. For the reasons above, Staff does not provide further testimony regarding Cost of Capital herein.

[1] See Stipulating Parties/100 Muldoon – Gehrke – Mullins – Bieber – Chriss – Ferchland, and Stipulating Parties/101, First Partial Stipulation.

Q. Are you proposing adjustments in Exhibit Staff/100 Muldoon?

A. No. John Fox in **Staff/200** will address Staff-proposed adjustments, including those reflecting Stipulating Parties' Partial Stipulation Resolving Cost of Capital.

Q. Does that conclude your testimony on Cost of Capital Issues?

A. Yes.

REVENUE REQUIREMENTS and STAFF ADJUSTMENTS

Q. What testimony addresses Revenue Requirement and Staff's summary of adjustments?

A. John Fox is the revenue requirements witness for Staff in this proceeding.[2] In **Staff/200**, he introduces Staff-sponsored adjustments and verifies PGE's proposed revenue requirement utilizing Staff's revenue requirement model. He also uses this model to calculate Staff's modified revenue requirement after incorporating Staff's proposed adjustments to the Company's revenue requirement.

HIGHLIGHTS

Q. What general observations do you have regarding PGE's general rate case and Staff's investigation?

A. One common theme in the testimony of Staff witnesses is concern regarding PGE's lack of focus on controlling its costs. PGE's testimony reflects a focus on innovation and meeting environmental goals rather than keeping rates as

[2] See **Exhibit Staff/200 Fox/1** regarding revenue requirement and Staff proposed adjustments.

affordable as possible for customers. PGE testifies regarding "its strategic vision to decarbonize, electrify and perform" that:

> We understand that our customers care deeply about the environment and the planet, and that they expect PGE to be a leader in addressing climate change and we are working to meet our shared priorities to accelerate sustainability and decarbonization. We also know customers want us to provide more offerings and better solutions for their individual energy needs, as well as customized options involving the deployment of new technologies and innovative programs and services.[3]

At a high level, Staff is concerned that PGE's focus on the environmental and innovative elements of its strategic vision may overshadow PGE's focus on controlling costs.

Q. Can you provide examples of the Company's lack of focus on controlling costs?

A. Staff witness Dr. Curtis Dlouhy testifies regarding an oversight in PGE Enterprise Risk Management protocols in 2020 that led to a large trading loss.[4] PGE has since changed its risk protocols, but Dr. Dlouhy questions whether PGE could do more to manage risk and protect customers.[5]

PGE's lack of focus on cost control may also be seen in PGE's accounting. Standard Data Requests 057 and 058 require utilities to file provide transactional data for all expenses and revenues for a base year and two preceding years as well forecasted expense for the Test Year, by FERC account, at the time they file a general rate case. Staff witness Brian Fjeldheim

3 PGE/100, Pope – Sims/7.
4 **Staff/600, Dlouhy/31-32**.
5 **Staff/600, Dlouhy47-55**.

testifies in Staff/500 that he struggled to obtain transactional data in response to these requests that was complete and internally consistent. Mr. Fjeldheim testifies that he spent a significant amount of time on the telephone, writing data requests, and in Teams Meetings to obtain data from PGE that reconciled and had sufficient detail to show what PGE spent its money on. Notwithstanding Mr. Fjeldheim's efforts, the FERC accounting information provided to Staff still includes over $5 million of transactions with no explanation indicating what they were for.[6]

Similarly, Staff witnesses Nadine Hanhan and Nick Sayen were unable to detect a focus on cost control for PGE's capital investments in transmission and distribution facilities. Both recommend excluding a portion of PGE's capital investments in transmission and distribution facilities including PGE's new Internal Operations Center (IOC), for apparent mismanagement of costs.[7]

Finally, Staff witness Moya Enright found a lack of attention to costs related to PGE's investment in repowering the Faraday hydro facility in Staff/1000. Ms. Enright notes that PGE did not consider all options before deciding to move forward with the repowering and significantly underestimated the cost of the option PGE did select.[8] Ms. Enright proposes an adjustment to the capital costs for the Faraday Repowering capital project based on these and other facts in her testimony.

Q. Does Staff have recommendations regarding cost control measures?

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6 **Staff/500, Fjeldheim**.
7 **Staff/600, Hanhan**; **Staff//800, Sayen**.
8 **Staff/1000, Enright.**

A. Staff's focus in this general rate case is not on recommending changes to PGE's cost management protocols, but on reviewing PGE's proposed revenue requirement. However, Dr. Dlouhy does make recommendations regarding PGE's risk management related to wholesale energy trading.

Q. Does Staff propose a new rate classification to implement House Bill 2475 that allows utilities to consider differential energy burdens on low-income customers and other economic, social equity or environmental justice factors that affect affordability for certain classes of utility customers in rate design?

A. Staff does not in this rate case. Staff witness Michelle Scala addresses House Bill (HB) 2475 in Staff/400. Ms. Scala notes the importance of including energy justice communities in consideration of differential rates for energy burdened customers. Ms. Scala testifies regarding the opportunity HB 2475 provides to bring broad stakeholder and community voices to the table in a joint effort to meaningfully address energy burden in Oregon and her conclusion that this discussion cannot be had in a general rate case for only one of the six investor-owned utilities operating in Oregon.[9]

Q. Vegetation management has increasing importance in today's climate. How does Staff address it in this case?

A. PGE has significantly increased the amounts included in its revenue requirement for Wildfire Mitigation and Vegetation Management (WMVM) as compared to its most recent rate case. Staff witness Dr. Dlouhy supports

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9 **Staff/400, Scala/43-44**.

PGE's focus on additional spending for WMVM. In fact, Dr. Dlouhy recommends the Commission adopt a performance-based adjustment mechanism for PGE's WMVM spending and establishing a deferral account in which the Company may place up to $6 million in incremental costs or decremental costs that differ from the costs included in rates. Any deferred costs would be subject to a subsequent prudence review and amortization. The amount of prudently incurred costs subject to amortization would be based on the number of vegetation management violations identified by Commission safety inspections and its impact on earnings thresholds.

To ensure PGE is also focused on cost control, even with respect to WMVM spending, Staff recommends that the Commission withhold 10 percent of PGE's proposed O&M expense from the Test Year. To the extent PGE's actual costs exceed its Test Year expense, it may recover its actual costs through the performance-based adjustment mechanism.

Q. Does Staff offer any other measures to reduce the impact of this rate case on customers?

A. Staff witness Steve Storm discusses an application to defer amounts for the Boardman coal facility recovered in PGE rates after the plant was retired. Mr. Storm notes that amounts recovered through this deferral can be used to offset the rate increase to customers.[10]

Q. Does this conclude your highlights of Staff's opening testimony?

A. Yes.

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[10] **Staff/1800, Storm**.

OVERALL SUMMARY

Q. What does PGE present as the key drivers for this general rate case?

A. In PGE's Executive Summary, PGE explains that it is seeking cost recovery for certain activities. In total, these expenditures represent a $59.0 million in incremental test year revenue, which equates to a 2.9 percent increase in base rates. These activities include:[11]

- Grid security, compliance, and modernization inclusive of IOC and ADMS;
- Repowering of the Company's Faraday powerhouse on the Clackamas River;
- Wildfire and major storm investment to improve reliability and resilience; and
- Transportation electrification efforts.

Further, PGE describes how it has worked efficiently with good cost control in all activities.

Q. Please describe factors Staff used to focus its review beyond necessary improvements to serve customers safely and reliably.

A. Staff also focused on the following factors in its review:

- Process and timing of investments;
- Alternatives considered;
- Risk management;
- Cost controls and overruns;
- Changes where costs should not be the responsibility of customers;

[11] See PGE/100 Pope – Simms, page 9,16,

- Reasonableness of loadings; and
- Process efficiency.

For example, a project that is not needed for some time into the future may not be used and useful upon completion. Other projects may have supply chain impacts from Covid-19 difficulties and not be able to be completed within the time frame addressed by this rate case. Further, PGE is held to a high standard of managing costs and risks to obtain targeted resources and benefits for customers at best prices. Staff's review in a rate case may identify costs associated with unfortunate circumstances that are not, or are not wholly, the responsibility of PGE's customers. It is also Commission practice to disallow some or all of certain costs incurred for reasons that do not directly benefit ratepayers.

Q. How does Staff present its opening testimony?

A. Staff is presenting the following opening testimony in 21 parts:

In Exhibit 200, John Fox, Senior Financial Analyst summarizes revenue requirement, discusses overall rate base and addresses PGE's income taxes. Staff adjustments recapped by Mr. Fox would reduce PGE's requested $2,105 test year revenue requirement as shown on **Staff/200 Fox/2**.

In addition, Mr. Fox reviews PGE's incentive payroll taxes, the Company's Oregon Corporate Activity Tax (CAT), Beaver modernization, and PGE's upgrade of its excitation system. He proposes increase and decrease adjustments for these on expenses and decrease adjustments on plant in service.

In Exhibit 300, Heather Cohen, Senior Utility Analyst, provides background, analysis, and recommendations regarding the Company's Test Year expense for wages, salary, incentives, and full-time equivalents. She also addresses Staff's proposed adjustments to the Company's Test Year expense for PGE's uncollectibles, customer accounts, advertising and promotional activities, and human resources / employee support budgets. Ms. Cohen proposes an adjustment for wages and salaries.

In Exhibit 400, Michelle Scala, Senior Utility Analyst, discusses Staff's analysis and position on the following issues: Test Year expense for Customer Services (Operations and Maintenance/Non-Labor); PGE's proposed changes to its decoupling mechanism; PGE's proposed changes to its tariffs for Street and Highway Lighting; Recovery of costs related to PGE's Fee Free Bank Card Payment Option; and House Bill 2475 Implementation. Ms. Scala proposes adjustments on nonresidential fee free bankcards, and on Customers Service expenses.

In Exhibit 500, Brian Fjeldheim, Senior Financial Analyst, presents analysis in the general categories of non-labor administrative and general expenses (A&G), information technology (IT) and IT projects, physical and cyber security, working capital, employee health insurance, other insurance, and amortization expense. Mr. Fjeldheim's testimony supports adjustments on A&G Expenses, IT Projects, and Cash Working Capital.

He also has some additional concerns regarding the preparation of the Company's Standard Data Requests (SDRs).

In Exhibit 600, Dr. Curtis Dlouhy, Senior Economist, analyzed Pension and Post-Retirement Medical Expense; Finance and Accounting Expense; Wildfire Mitigation and Vegetation Management; Enterprise Risk Management (ERM), and August 2020 Trading Losses; Monetary Trading Losses Taken Out of Rates; Personnel Changes Following the Trading Losses; and Risk Practice Changes Following the Trading Losses. Dr. Dlouhy proposes an adjustment on pension expenses and wildfire mitigation and vegetation management. He particularly focuses on PGE trading floor losses.

In Exhibit 700, Nadine Hanhan, Senior Utility Analyst, describes her review of the capital costs of PGE's transmission projects and some projects that are a combination of transmission and distribution (together referred to as "transmission projects"). Ms. Hanhan also provides a brief overview of the PGE's proposed treatment of any increases in transmission sales revenue that may stem from PGE's planned FERC rate case, in addition to an update on PGE's reclassification of assets as a result of docket UM 2031. Ms. Hanhan's testimony supports adjustments on Transportation and Distribution (T&D) projects.

In Exhibit 800, Nick Sayen reviews PGE's investment in an Advanced Distribution Management System (ADMS), ADMS operations and maintenance (O&M), distribution projects, and projects that are a combination of distribution and transmission (together referred to as "distribution projects"). Mr. Sayen proposes adjustments on ADMS and Distribution Projects.

In Exhibit 900, Scott Gibbens, Manager of Policy and Economic Analysis, reviews PGE's proposed non-bypassable charges and the Company's load forecast for the test year. Mr. Gibbens provides an overview of COVID-19 impacts, from a rate case perspective.

In Exhibit 1000, Moya Enright, Senior Economist, looks at fuel stock, inclusive of fuel stock by fuel type, and timeline for surrender of Carbon Dioxide (CO_2) allowances; PGE's Faraday Repowering Project; and affiliated interest transactions. Her testimony supports dissallowances for elements of fuel stock and Faraday Repowering. Ms. Enright proposes adjustments on Fuel Stock and Faraday Repowering.

In Exhibit 1100, Mitch Moore, Senior Utility Analyst, presents Staff's analysis and recommendations regarding the treatment of non-labor generation O&M; non-labor transmission and distribution O&M; directors' and officers' insurance and expenses; major maintenance agreements; non-fuel materials and supplies; and miscellaneous deferrals.

In Exhibit 1200, Paul Rossow, Utility Analyst, testifies regarding adjustments to the Company's proposed Test Year expense for certain discretionary spending and membership dues that should not be borne by ratepayers. His recommended adjustments are derived from review of multiple data responses, analysis PGE's 2020 Operations and Maintenance (O&M)

non-payroll transactions for FERC Accounts 500 through 935, and Commission membership policy. Mr. Rossow proposes adjustments on CAISO membership cost reduction, and meals and entertainment.

In Exhibit 1300, Kathy Zarate, Utility Economist, discusses the Company's loss and/or gains on sales of utility property, and PGE's test year forecast of Other Revenue. Ms. Zarate's testimony supports adjustment on Other Revenues.

In Exhibit 1400, Dr. Max St. Brown, Senior Utility Analyst, discusses PGE's proposed changes to PGE's Level III Outage Mechanism, marginal cost of service study, and rate spread and rate design. Dr. St. Brown proposes adjustment to the Level III Outage Mechanism.

In Exhibit 1500, Ming Peng, Senior Econometrician, presents Staff analysis of the depreciation expense and accumulated depreciation, or depreciation reserve. Ms. Peng also reviews the Allowance for Funds Used During Construction (AFUDC) portion of revenue requirement for this general rate case.

In Exhibit 1600, Anna Kim, Senior Utility Analyst, presents Staff analysis on cost recovery for Research and Development.

In Exhibit 1700, Eric Shierman, Senior Utility Analyst, discusses issues associated with the following topics relating to transportation electrification (TE): PGE's proposed Schedule 150; Line extension allowances for TE projects; PGE's recovery on TE programs the Commission has approved; and PGE's recovery on TE programs the

Commission has not approved. Mr. Shierman's testimony supports adjustments to Line Extension Allowances and Transportation Electrification projects, both those approved by the Commission and those that did not obtain Commission approval.

In Exhibit 1800, Steve Storm, Senior Economist, addresses a request for deferral of expenses and capital costs related to the retired Boardman coal-fueled plant (Boardman) that are currently included in the retail rates of Portland General Electric Company (PGE or Company).

In Exhibit 1900, Rose Anderson, Senior Economist evaluates the Company's proposed Schedule 146 for recovery of Colstrip revenue requirement.

In Exhibit 2000, J.P. Batmale, Division Administrator of the Commission's Energy Resources and Planning Program, testifies regarding the activities and associated staffing levels by PGE related to certain public policy areas and the Company's proposed Test Year expense for staff hiring.

In Exhibit 2100, Nick Sayen, in his **second** testimony, describes Staff's preliminary analysis of the PGE Online Marketplace platform (Marketplace).

TRADING FLOOR SUMMARY

Q. Please explain how Staff presents its position on PGE's trading losses.

A. Staff witness Dr. Dloughy evaluated PGE's risk management improvements subsequent to the Company's trading losses in August of 2020. Further, Dr. Dlouhy aggregates individual Staff findings regarding whether trading loss impacts were appropriately backed out of test year revenue requirement in their areas of review. Dr. Dlouhy summarizes all of Staff's adjustments regarding trading floor losses in **Staff/600**.[12]

Please note that Dr. Dlouhy's examination was narrowly focused on the appropriate treatment of PGE's trading losses within this rate case and cannot be extrapolated to presume conclusions about issues not specifically addressed in Staff's opening testimony.

COVID-19 SUMMARY

Q. How did Covid-19 affect this general rate case?

A. Mr. Gibbens addresses Covid-19 impacts within this general rate case. He summarizes how Covid-19 pandemic affected what individual Staff did in this general rate case and provides his findings in **Staff/900**.[13] Note that his summary is restricted to issues impacting this general rate case.

STAFF CONCERNS WITH STANDARD DATA REQUESTS

Q. Does Staff explain its concern in Opening Testimony that PGE responses to SDR Nos. 57 and 58 were not complete and answered correctly at the time of filing?

A. Yes. Mr. Fjeldheim describes the issue in detail in his testimony. Mr. Fjeldheim and other Staff met with PGE in advance of this general rate case to clarify that deficient and inaccurate responses to these SDRs would result in

12 See **Staff/600 Dlouhy**.
13 See **Staff/900 Gibbens**.

the need for supplemental responses requiring the Company and Staff to have to redundantly address the same material.

Q. Are the responses Nos. 57 and 58 still deficient?

A. Yes. SDR 57 requests non-payroll transactional base year data by FERC account and other fields plus requires a business description for each transaction. Staff makes an initial determination whether the expense appears to be a reasonable business cost incurred in delivering regulated service to Oregon customers by reviewing the transactional descriptions contained in these SDRs. Based on this data, Staff may eliminate imprudent, excessive, or discretionary expenses. Review of this detail is essential for eliminating costs like branding, entertainment, lobbying, excessive affiliated payments, gifts, and awards, etc.

SDR 58 requests historical years of accounting data by FERC account to compare to the utility's base year and forecasted test year to determine whether pro forma adjustments are necessary to the test year. These may be normalizing adjustments, annualizing adjustments, escalation adjustments, or nonrecurring expense adjustments etc.

Q. Can PGE improve its response to these SDR 57 and 58 in its next general rate case?

A. Yes. Staff invites the Company in its next round of testimony to describe the difficulties it faced in meeting Staff expectations and the changes it has made to preclude such inefficiencies in its next general rate case filing.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is John L. Fox. I am a Senior Financial Analyst employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the changes in revenue requirement associated with Staff's opening position. Additionally, I provide background regarding specific issues I reviewed, and my analysis and recommendations.

Q. How is your testimony organized?

A. My testimony is organized as follows:

INTRODUCTION

Q. What is the change in revenue requirement recommended by Staff?

A. Staff proposes to reduce the Company's requested revenue requirement increase from $99.0 million to ($3.7) million. This overall reduction is inclusive of the net variable power cost settlement in Docket No. UE 391 and the stipulation reducing the overall rate of return, as well as additional reductions proposed by Staff.

Q. What areas of PGE's filing are you primarily responsible for reviewing?

A. I reviewed portions of the Company's filing related to retail sales revenue, taxes other than income, income taxes, utility plant, escalation, and regulatory adjustments. In order to gain additional insight, I reviewed the Company's responses to Staff's Standard Data Requests (SDRs), issued approximately 70 additional data requests (DRs), and reviewed the Company's responses.

Q. Are you discussing all of the issues described above in your opening testimony?

A. No. I discuss only issues for which I am proposing revenue requirement adjustments and the general requirements for review of income taxes and utility plant.

Q. Are additional adjustments for these issues proposed by other Staff?

A. Yes. The Company's filing is complex, and a thorough review can involve multiple Staff members looking at each issue. In particular, individual Staff are reviewing additions to different categories of utility plant (e.g. production, transmission, distribution, etc.) and the effects of escalation on individual accounts.

Q. Why is it necessary to evaluate the effects of escalation for particular accounts?

A. The Company does not simply escalate actual costs for the 2021 base year. As explained in testimony:

> [T]he revenue requirement is based on PGE's 2021 budgets, which were originally based on a 2020 budget that reflected Commission Order No. 18-464 for 2019 prices. The 2021 budgets were escalated for inflation to 2022 and adjusted for known and measurable changes.[1]

Accordingly, the 2021 budget associated with a particular topic many have been increased prior to applying the 2022 escalation factors[2] noted in the Company's testimony.

Q. What adjustments are you proposing to the Company's revenue requirement?

A. I propose a downward adjustment to payroll tax and rate base related to incentive pay, inclusion of the Oregon Corporate Activity Tax in base rates, removal of a project from rate base due to a delayed in-service date, and removal of costs associated with another project that is not yet in service.

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[1] PGE/200, Tooman-Batzler/7.
[2] *Id*.

SUMMARY OF REVENUE REQUIREMENT

Q. Please provide background on how the Commission reviews a utility's general rate case filing.

A. The rates charged by a utility are based on the utility's "revenue requirement." To determine a utility's revenue requirement, the Commission determines for a specified test year: (1) the utility's forecasted gross revenues; (2) the utility's operating expenses to provide utility service; (3) the rate base on which a return should be earned; and (4) the rate of return to be applied to the rate base.[3] Once a utility's revenue requirement is established, the Commission determines the rates the utility must charge different classes of customers to collect that revenue requirement, considering the different costs different classes of customers impose on the utility's system.[4]

Q. What is the revenue requirement increase proposed by PGE in this docket?

A. PGE proposes an overall increase of $99.0 million or 4.9 percent.[5] The Company further states that the all-in price increase is comprised of the following: 2 percent for Net Variable Power Costs (NVPC); 2.9 percent base rate increase; less 0.9 percent for supplemental schedules and less 0.1 percent for cycle basis billing.[6]

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[3] Order No. 01-787, pp. 5-6.
[4] Order No. 86-477 (1986 WL 1300169).
[5] PGE/200, Tooman-Batzler/3.
[6] PGE/100, Pope-Sims/1.

Q. Please discuss how the Colstrip isolated revenue requirement is related to the overall increase.

A. The Company states that Colstrip isolated revenue requirement comprises $55.9 million of the $59 million base rate increase.[7] Staff notes this is the majority of the 2.9 percent figure quoted above. The Company further proposes to isolate all identifiable Colstrip-related costs (both expense and capital related costs), remove them from PGE's base rate schedules, and include them for recovery within PGE's Schedule 146.[8]

Q. PGE states that the combined increase is offset by a rate credit of approximately 1.0 percent in PGE's supplemental schedules, also effective January 1, 2022, for an overall net rate increase of 3.9 percent.[9] What is Staff's understanding of the "rate credit"?

A. The "rate credit" results from the new tariff schedules 138 and 150 proposed in this docket, as well as ratemaking adjustments for other schedules in other Commission dockets that will occur irrespective of the Company's request for a general rate revision.

The overall "rate credit" is comprised of changes in the following supplemental schedules:

- 105 – Regulatory Adjustments
- 123 – Decoupling Adjustment
- 131 – Oregon Corporate Activity Tax Recovery
- 135 – Demand Response Cost Recovery Mechanism
- 136 – Oregon Community Solar Program Cost Recovery Mechanism

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7 PGE/200, Tooman-Batzler/2.
8 PGE/1200, Macfarlane-Tang/49.
9 PGE/200, Tooman-Batzler/3.

- 137 – Customer-Owned Solar Payment Option Cost Recovery Mechanism
- 138 – Energy Storage Cost Recovery Mechanism
- 145 – Boardman Power Plant Decommissioning Adjustment
- 150 – Transportation Electrification Cost Recovery Mechanism

Q. Have the parties agreed to adjust certain components of the $99 million overall increase?

A. Yes, the parties have agreed to reduce Net Variable Power Cost by $6.5 million from $511.8 million to $505.3 million.[10]

The parties have also agreed to reduce the overall Rate of Return (ROR) from 6.938 percent in the filed case to 6.813 percent. This adjustment, including interest synchronization, reduces the Company's revenue requirement by $7.4 million.

Q. Are Staff proposing additional adjustments to the Company's revenue requirement?

A. Yes, Staff propose to reduce the Company's revenue requirement by an additional $88.8 million. The specific rate case topics, responsible Staff, and proposed changes in revenue requirement are summarized in the following table:

[10] See *In the* Matter of *PORTLAND GENERAL ELECTRIC COMPANY, 2022 Annual Power Cost Update Tariff (Schedule 125),* Docket No. UE 391, Stipulating Parties / 100, Enright – Gehrke – Mullins – Batzler / 22, filed August 30, 2021.

PGE
STAFF ISSUE SUMMARY
Twelve Months Ended 12/31/22
($000)

Incremental Revenue Requirement on the Company's Filed General Rate Case Results							$98,967
Testimony	**Issue No.**	**Staff**	**Proposed Staff Adjustments**	**Revenue**	**Expense**	**Rate Base**	**Revenue Requirement Effect**
200 / 6	S-1	Fox	Cost of Capital (includes interest sync.)	0	0	0	(7,415)
200 / 6	S-2	Fox	Net Variable Power Costs	0	(6,500)	0	(6,721)
200 / 13	S-3	Fox	P36836: Beaver Modernization	0	0	(10,172)	(901)
200 / 14	S-4	Fox	P36444 Upgrade Excitation System	0	0	(350)	(31)
200 / 23	S-5	Fox	Incentive Payroll Taxes	0	(798)	(4,399)	(1,215)
200 / 26	S-6	Fox	Oregon Corporate Activity Tax	0	7,784	0	8,049
300 / 21	S-7	Cohen	Wages & Salaries	0	(10,188)	(5,808)	(11,049)
1200 / 6	S-8	Rossow	Membership Costs	0	(137)	0	(142)
1200 / 6	S-9	Rossow	CAISO Membership	0	(600)	0	(620)
1200 / 10	S-10	Rossow	Meals and Entertainment	0	(273)	0	(283)
1300 / 4	S-11	Zarate	Other Revenues	[redacted]	0	0	[redacted]
1400 / 8	S-12	St. Brown	Level III Storm Accrual	0	(6,919)	0	(7,154)
1700 / 5	S-13	Shierman	Line Extension Allowances	0	0	(212)	(19)
1700 / 10	S-14	Shierman	Approved TE Programs	0	(1,879)	(368)	(1,975)
1700 / 15	S-15	Shierman	Unapproved TE Programs	0	0	(8,489)	(752)
500 / 2	S-16	Fjeldheim	A&G Expense	0	[redacted]	0	[redacted]
500 / 12	S-17	Fjeldheim	IT Projects	0	0	(11,597)	(1,028)
500 / 26	S-18	Fjeldheim	Cash Working Capital	0	0	(5,565)	(493)
	S-19	Fjeldheim	No Adjustment	0	0	0	0
600 / 14	S-20	Dlouhy	Pension Adjustment	0	(2,610)	0	(2,699)
1000 / 13	S-21	Enright	Faraday Disallowance	0	0	(17,700)	(1,568)
1000 / 4	S-22	Enright	Fuel Stock Adjustment	0	0	[redacted]	[redacted]
700 / 2	S-23	Hanhan	T&D Projects	0	0	(38,810)	(3,439)
400 / 26	S-24	Scala	Nonresidential Fee Free Bank Card	0	(907)	0	(938)
400 / 2	S-25	Scala	Customer Service Expense	0	(889)	0	(919)
800 / 2	S-26	Sayen	ADMS and Distribution Projects	0	0	(50,388)	(4,465)
600 / 31	S-27	Dlouhy	Wildfire Mitigation and Vegetation Mgmt.	0	(3,000)	0	(3,102)

Total Staff-Proposed Adjustments	**$ (102,661)**
Staff-Calculated Revenue Requirements Change	**($3,694)**

OVERALL RATE BASE

Q. Please summarize the Company's rate base filing.

A. The Company provides Exhibit 208 showing how rate base has changed compared to the UE 335 approved amounts:

- Plant in service increased by $1.484 billion
- Net utility plant increased by $986 million (net of accumulated depreciation and deferred taxes)

The Company also testifies that "[t]he increase is primarily attributable to the growth in distribution plant, including the IOC as discussed in PGE Exhibit 800, as well as the Wheatridge wind generation plant and Faraday Repower Project as discussed in PGE Exhibit 700."[11]

Q. Please discuss Staff's overall approach to review of plant additions.

A. In order to include new capital investment in rate base, a utility must make two showings. "First, it must show that the investment is presently used for providing utility service. Second, it must show that the investments were prudently made, based on the information that it knew or should have known at the time."[12]

Q. What is the Oregon law requiring utility plant to be presently used before it may be included in rates?

A. ORS 757.355 requires utility plant to be presently used for providing utility service to customers and creates what is generally referred to as a "used and

[11] PGE/200, Tooman-Batzler/24.
[12] *See* e.g., Order No. 12-493 (UE246).

useful" standard requiring the property to be placed into service prior to the effective date of the rates. ORS 757.355 provides:

> (1) Except as provided in subsection (2) of this section, a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer.
>
> (2) The Public Utility Commission may allow rates for a water utility that include the costs of a specific capital improvement if the water utility is required to use the additional revenues solely for the purpose of completing the capital improvement. [1979 c.3 §2; 2003 c.202 §2]

Q. Please discuss the Commission's standard of review for prudence.

A. The purpose of the prudence review has been succinctly stated by the Commission in prior rate cases:

> [W]e take this opportunity to clarify the prudence standard in ratemaking. Parties have raised questions about how the Commission applies the prudence standard, particularly with regard to the relevance of the decision-making process that a utility uses to make an investment.
>
> The prudence standard is traditionally used to address the proper valuation of utility investment in rate base. Any investment found to be unreasonable is deemed imprudent and subject to partial or full disallowance. An example of a modem articulation of the prudence standard is as follows:
>
> A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems

> prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the task that confronted the company.
>
> Although the Oregon courts have not expressly discussed the applicability of the prudence standard in this state, this Commission has long used the standard when examining utility investments. Through various orders, the Commission has confirmed that prudence of an investment is measured from the point of time of the utility's actions and decisions without the advantage of hindsight, that the standard does not require optimal results, and the review uses an objective standard of reasonableness.[13]

Q. Please explain your application of the used and useful standard to PGE's new plant.

A. The additions in plant since the rate effective date of the UE 335 rate case and before the rate effective date in this case (April 30, 2022) can be thought of as two components: (1) the actual plant in service at December 31, 2020, which articulates with PGE's annual results of operations[14] and FERC forms;[15] and (2) the Company's *estimate* of additional plant expected to enter service through April 30, 2022. Staff's review of new plant focused on the new plant expected to enter service after December 31, 2020, and before April 30, 2022.

Staff's initial approach was to gather lists of projects with a CWIP value exceeding $1 million on the annual FERC forms[16] and those exceeding $500 thousand in the 16-month estimated period (Jan 2020 – Apr 2022).

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[13] See *In the Matter of PacifiCorp Request for a General Rate Revision,* Docket No. UE 246, Order No. 12-493, Dec 20, 2012, at 25.

[14] See *In the* Matter *of PORTLAND* GENERAL *ELECTRIC COMPANY's Results of Operations Report for 2011*, Docket No. RE 119, most recently supplemented April 22, 2021.

[15] See *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Reports in compliance with OAR 860-027-0070 (1) and (2),* Docket No. RE 54, most recently supplemented April 30, 2021.

These lists, along with the narrative discussion in the Company's initial filing, became a starting point for further Staff inquiry.

Q. Why did Staff use $500 thousand as the threshold for Staff's review of projects within the 16-month estimation period?

A. Because the projects are not yet completed and in service, Staff felt granularity down to this level was necessary. However, as noted above, this was just a starting point for analysis and Staff will examine projects under that amount as needed.

Q. Are you proposing adjustments to utility plant in service based on the used and useful standard?

A. Yes. Again, several Staff are reviewing additions to different categories of utility plant. Adjustments resulting from those reviews are presented in their respective testimonies. Regarding projects I reviewed, I propose two adjustments in Issues 2 and 3 below. Additionally, my review of payroll taxes includes an adjustment to rate base as further discussed in Issue 4 below.

Q. Do you have any other recommendations regarding plant that is not yet in service but is expected to be by the rate effective date?

A. Yes. In UE 335, the Company agreed to file an attestation for all large non-blanket projects with costs projected to be $5 million or greater and that were expected to close by year-end 2018. There were seven large capital projects that met those criteria.

Due to the rate effective date not being a calendar year end,[17] Staff recommends attestations for projects over $1 million placed into service January to April 2022.[18] This will give greater assurance that utility plant is not overvalued at the rate effective date.

Q. You have discussed your analysis of whether new plant additions are used and useful. What are your conclusions regarding the prudence of the plant you reviewed?

A. I reviewed the project justification forms and issued a number of additional data requests regarding the following projects. Based on my review, I did not find any information indicating that any of the projects were imprudently built. Accordingly, I am not proposing any prudence adjustments for them.

P36394 Vintage Vehicle Replacement II
P36836 BR: Beaver Modernization
P36723 Field Area Network Project (FAN)
P35172 PSES - Generation Fitness Fund
P35938 Field Voice Communications System
P35228 Clackamas PME Road Fund
P36105 Dispatchable Standby Generation (DSG)
P37049 Line Crew Truck Stock Materials
P37095 SCADA Replacement - Grizzly Substation
P35591 As-Built Drawings - Generation
P36742 RM: Rewind Units 3, 2, 1
P36464 Facilities Asphalt R&R Project
P36602 RB: Replace Hatchery Chiller System
P35959 WSH Structural/Reliability Upgrades
P36285 Purchase T&D - Tools & Lab Equipment
P35894 Communications Fitness
P35565 PSES - Generation Site Paving
P23970 Corporate Strategic Fiber Project

[17] In other words, due to the delayed effective date, the Company's case includes capital additions through the first four months of the 2022 test year.

[18] Docket No. UE 335, *PGE's Compliance per Order 18-464, Attestation for Plant in Service*, filed February 15, 2019.

ISSUE 1. P36836: BEAVER MODERNIZATION

Q. Please describe this project.

A. PGE describes the project as follows:

> Modernization efforts at the Beaver plant to upgrade the gas turbine combustion systems from a dual fuel system to a single fuel dry low NOx system to reduce overall emissions. The single fuel will be natural gas and the upgraded units will be prevented from operating on fuel oil as an alternative. The combustion upgrade will allow for greater operationally flexibility while meeting PGE's commitment to reduced greenhouse gas emissions at the site.[19]

In the filed case, the forecasted additions included in rate base for this project is $10.2 million expected to be placed in service in April 2022.

Q. Has the project been delayed?

A. Yes. PGE has stated, in response to Staff inquiry, that more recent information reflects an in-service date of June 2022.[20]

Q. Regarding the revenue requirement, what does the Company propose?

A. The Company proposes that if the project timeline does not move back to a completion date in April of 2022, PGE will remove the cost of the project from the 2022 rate base in a subsequent revenue requirement update.

Q. What does Staff recommend?

A. Staff recommends removal from the revenue requirement at this time based on the information provided.

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[19] Response to Staff DR 143, UE 394_OPUC DR 143_Attach 3.xlsx.
[20] Response to Staff DR 276a.

ISSUE 2. P36444 UPGRADE EXCITATION SYSTEM

Q. Please describe this project.

A. This project establishes a fund to replace or rewind failed substation transformers, so that PGE will be more resilient to a wider variety of disaster scenarios. The estimated project cost is $3.7 million expected to be placed in service in 2023 and 2024.[21]

Q. Has a portion of the project been included in rate base in this case?

A. PGE has stated, in response to Staff inquiry, that approximately $350,000 of capital costs associated with project planning activities are included in PGE's rate base on April 30, 2022.[22]

Q. Does this cause broader concerns for Staff?

A. Yes. As I have discussed above, ORS 757.355 requires that "a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer." In Staff's view, project planning activities pertaining to a future project clearly is not an expenditure presently used for providing utility service to the customer. That such an expenditure is included in rate base begs the question of if similar items are being capitalized in this case.

Q. Did Staff conduct further inquiry?

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[21] Response to Staff DR 142, UE 394_OPUC DR 142_Attach A.xlsx.
[22] Response to Staff DR 269a.

A. Yes. With respect to projected plant additions over $500 thousand in the sixteen-month period Jan 2021 through April 2022, PGE represents that there are no other projects for which preliminary costs are included in PGE's UE 394 rate base but the project itself is not yet in service.[23]

Q. What does Staff recommend?

A. The $350,000 of project planning activities must be removed from rate base.

[23] Response to Staff DR 563a.

ISSUE 3. CONSTRUCTION OVERHEAD

Q. Is Staff proposing an adjustment to rate base related to construction overhead?

A. Not at this time, however Staff is concerned that ratepayers are potentially being double charged due to fluctuations in overhead allocations between rate cases and the resulting impact on capitalized expenses.

Q. Please summarize information provided by the Company regarding cost allocation.

A. The Company has provided several documents in response to Staff's initial round of pre-filing standard data requests.[24] Specifically, the following:

- PGE's Cost Allocation Manual;
- PGE's Capital Accounting Policy; and
- The capitalization policy footnote from the Company's most recent SEC 10k filing.

Q. Is the cost allocation plan filed annually as part of an ongoing docket?

A. Yes, as part of the Company's affiliated interest filing.[25]

Q. Does PGE assert that its cost allocation method has been consistently applied?

A. Yes, the Company states that the cost allocation methodology was reviewed by Staff in 2004 and has been little changed since, stating the following:

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[24] Response to Staff DR 80, UE 394_OPUC DR 080_Attach A, UE 394_OPUC DR 080_Attach B, UE 394_OPUC DR 080_Attach C.

[25] See *In the Matter of* PORTLAND *GENERAL ELECTRIC COMPANY Annual Affiliated Interest Report as Required by OAR 860-027-0100,* Docket No. RE 64.

> Although PGE replaced its financial system in 2012, it did not significantly alter the method of calculating its loadings and allocations then or since. Instead, we revise the rates based on updated costs from year to year and occasionally revise the cost criteria based on changing conditions.[26]

Q. For final revenue requirements purposes, what was the overall split for labor (including contract labor), including overheads, between expense and capital assumed in the UE 335 docket?

A. The Company provides a calculation based on its 2019 FERC Form 1 filing showing that 37.57 percent of labor was allocated to capital projects.[27] Staff notes that 2019 was the test year in the UE 335 rate case.

Q. Why did you use the FERC 2019 values for the UE 335 split?

A. PGE states that it did not rely on an overall labor split for purposes of calculating a final revenue requirement in Docket No. UE 335.[28] Staff's understanding of the Company's response is that that there are multiple overhead rates in the revenue requirement, both actual results and projected rates so they are unable to provide an overall blended rate. Therefore, PGE suggests using the 2019 FERC figures as a proxy for the test year.

Q. With this background in mind, please elaborate on the nature of Staff's concern.

A. While yet to be confirmed by the Company, based on the Company's 2020 FERC Form 1, Staff calculates the proportion of labor applied to capital using the same methodology was 40.63 percent. Furthermore, Staff calculates the

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[26] Response to Staff DR 811.
[27] Response to Staff DR 766 and UE 394_OPUC DR 766_Attach A.xlsx.
[28] Response to Staff DR 766.

higher percentage caused an additional $9.7 million to be allocated to capital projects.

As the current tariffs reflect the lower capital rate, ratepayers can be thought of as being charged twice, once as cost of service O&M in the current tariff and again over time as the higher than forecasted capital costs are depreciated in future years.

Q. What does Staff recommend?

A. Staff recommends establishing a process to memorialize the ongoing changes in allocation percentages between rate cases and further inform the parties so that they might consider if additional ratemaking adjustments are necessary on a prospective basis.

TAXES

Q. Please summarize the Company's filing related to income taxes.

A. Calculation of test year income taxes of $93.4 million is presented in PGE Exhibit 205. The total tax includes a credit of $9.156 million appearing on Exhibit 205 labeled as "ITC". However, PGE's testimony states this amount is the ongoing return of excess deferred income taxes from the 2017 tax reform act (ARAM EDIT).[29]

PGE's Exhibit 208 presents a decrease in the amount of accumulated deferred income taxes (ADIT) from $685.811 million to $681.954 million. PGE testifies that deferred income taxes have been reduced by $18.4 million for the tax impact of production tax credits not used due to the 2020 energy trading losses.[30]

Staff notes that unused PTC creates a deferred tax asset and the net deferred tax overall is a liability, removing the PTC related asset increases the net liability therefore reducing rate base.

Q. What are the requirements of Oregon law regarding the inclusion of income taxes in utility rates?

A. Income taxes in utility rates are subject to the requirements of ORS 757.269.

> **757.269 Setting of rates based upon income taxes paid by utility; limitation on use of tax information; rules.**
> (1) When establishing schedules and rates under ORS 757.210 for an electricity or natural gas utility, the Public Utility Commission shall act to balance the interests of the customers of the utility and the utility's investors by setting fair, just and reasonable rates that include amounts for income taxes. Subject

29 PGE/200, Tooman-Batzler/20.
30 PGE/200, Tooman-Batzler/4.

to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operations of the utility.

(2) During ratemaking proceedings conducted pursuant to ORS 757.210, the Public Utility Commission must ensure that the income taxes included in the electricity or natural gas utility's rates:

(a) Include all expected current and deferred tax balances and tax credits made in providing regulated utility service to the utility's customers in this state;

(b) Include only the current provision for deferred income taxes, accumulated deferred income taxes and other tax related items that are based on revenues, expenses and the rate base included in rates and on the same basis as included in rates;

(c) Reflect all known changes to tax and accounting laws or policy that would affect the calculated taxes;

(d) Are reduced by tax benefits generated by expenditures made in providing regulated utility service to the utility's customers in this state, regardless of whether the taxes are paid by the utility or an affiliated group;

(e) Contain all adjustments necessary in order to ensure compliance with the normalization requirements of federal tax law; and

(f) Reflect other considerations the commission deems relevant to protect the public interest.

(3) During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes as part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon:

(a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation;

(b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or

(c) Any other considerations the commission deems relevant to protect the public interest.

(4)(a) Because tax information of unregulated nonutility business in an electricity or natural gas utility's affiliated group is commercially sensitive, and public disclosure of such information

> could provide a commercial advantage to other businesses, the Public Utility Commission may not use the tax information obtained under this section for any purpose other than those described in this section, in ORS 757.511 and as necessary for the implementation and administration of this section and ORS 757.511.
>
> (b) The commission shall adopt rules to implement paragraph (a) of this subsection that:
>
> (A) Identify all documents and tax information that an electricity or natural gas utility must file in its initial filing in a proceeding to change rates that include amounts for income taxes, recognizing that any party may object to providing such documents on the grounds that they are not relevant; and
>
> (B) Determine the procedures under which intervenors in such proceedings may obtain and use documents and tax information to fully participate in the proceeding.
>
> (5) As used in this section, "affiliated group" means a group of corporations of which the public utility is a member and that files a consolidated federal income tax return. [2011 c.137 §1]

Q. Please summarize Staff's review of income taxes in this case.

A. Staff initially reviewed tax information in the Company's FERC Form 1 filings, issued data requests, and reviewed the Company's responses to data requests issued by intervening parties.[31] Staff concludes that the Company's provision for tax appears to be correctly calculated for rate making purposes. Staff's examination and discovery included confirming the federal and state tax rates, apportionment calculations, calculation of current and deferred income tax expense, application of federal and state tax credits, and the ongoing amortization of excess deferred income taxes (EDIT) resulting from the 2017 Tax Act.

[31] FERC Form 1 pages 261-274, responses to Staff DR 114-118, 146, 287, 568, and responses to AWEC DR 27, 28, 31, 96, 99, and 112.

Q. Is Staff proposing adjustments to income tax expense other that those necessary to finalize the Company's revenue requirement?

A. Not at this time.

ISSUE 4. INCENTIVE PAYROLL TAXES

Q. Please summarize the Company's filing regarding payroll taxes.

A. PGE states that payroll taxes are estimated by applying an approximate 8.0 percent payroll tax rate to total wages and salaries.[32]

Q. Does this statement agree with the information presented in the case?

A. Not exactly. The percentage obtained by dividing the total payroll taxes in PGE Exhibit 206 by total wages as presented in PGE Exhibit 30 is 8.71 percent.

Q. Can additional inferences be drawn from Exhibit 206 and 301?

A. Yes, because the figures for cost elements 1502 and 1602 are included in Exhibit 302, Staff calculates that approximately 0.8 percent of the payroll tax expense is related to incentives. Staff's analysis is presented in the following table:

Table 1

Exh 206 / Exh 301	w/o contract labor	PGE Adj. DR 767	Incentive share
7.7%	9.3%	8.5%	0.8%
8.0%	9.4%	8.7%	0.7%
7.9%	8.9%	8.3%	0.6%
8.7%	9.1%	8.3%	0.8%
8.7%	9.1%	8.3%	0.8%

Q. Has the Company provided the amount of test year payroll tax related to these incentives?

32 PGE/200, Tooman-Batzler/23.

A. Yes. The Company states that $1,396,105 is included in the filed case, 45.9 percent of which was included in cost allocations.[33] This explains the variance in payroll tax and the incentive portion calculated by Staff above.

Q. Is the percentage includable in cost allocation the same as the percentage that is charged to capital projects?

A. In Staff's understanding, no.

The Company states that payroll taxes are a labor loading that is classified as A&G cost.[34] These costs are then distributed to PGE's capital, non-utility, and the co-owned entities through the Corporate Governance allocation resulting in a 39.48 percent allocation to utility capital in 2020.[35]

However, in Staff's understanding, the $1.396 million figure above is already net of the non-utility and co-owned entity calculations and ought to be allocated at a higher rate of 42.8 percent.[36]

Q. Has allocation of incentives to rate base been addressed in a previous rate case?

A. Yes, in Order No. 14-422 the Commission determined that rate base would be reduced by $10 million in recognition of past capitalized financial performance-based incentives. For regulatory purposes, this $10 million rate base

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33 Response to Staff DR 570 subsequently revised in response to Staff DR 767.
34 Response to Staff DR 80, UE 394_OPUC DR 080_Attach A.pdf at 4.
35 *Id.* at 12.
36 *Id.* Utility share is 39.48 + 52.71 = 92.19 percent. 39.48 / 92.19 = 42.8 percent.

adjustment was to be amortized over 20 years resolving all issues regarding past capitalization of incentives.[37]

Staff notes that the remaining portion of this incentive rate base adjustment appears in this case on Exhibit 208, line 18.

Q. Is a prior year rate base adjustment warranted?

A. Yes, apparently the payroll taxes related to these incentives have been allocated to capital all along. Staff proposes a rate base adjustment from 2015 through April 2022. This is the period of time that has elapsed subsequent to the stipulation discussed above.

Q. What is Staff's proposed adjustment?

A. Staff proposes a reduction of O&M by $798 thousand and a rate base reduction of $4.4 million, calculated as follows:

Table 2

	O&M	Capital
Test year:		
Payroll Tax	$ (1,396,105)	$ (1,396,105)
2022 Allocation %	57.2%	42.8%
Adjustment	(798,229)	(597,877)
Estimate since 2014:		
2022 (4 mos.)		(199,292)
2021		(600,000)
2020		(600,000)
2019		(600,000)
2018		(600,000)
2017		(600,000)
2016		(600,000)
2015		(600,000)
	$ (798,229)	$ (4,399,292)

[37] See *In* the *Matter of PORTLAND* GENERAL *ELECTRIC COMPANY*, *Request for a General Rate Revision*, Docket No. UE 283, Order No. 14-422, Appendix B, at 2.

ISSUE 5. OREGON CORPORATE ACTIVITY TAX

Q. Please summarize the Company's filing regarding the Oregon Corporate Activity Tax (OCAT).

A. PGE states the following:[38]

> We did not include the OCAT in this GRC because PGE has not yet filed a return for the tax, and thus, PGE has too little experience with the tax to determine a forecast amount for the 2022 test year. In short, PGE needs additional time to evaluate how the tax operates, how much expense it will generate, and how much variability it will entail before including OCAT in a GRC. Consequently, PGE proposes to continue to defer the OCAT as part of Docket No. UM 2037 until a future GRC.

Q. Please describe the OCAT.

A. The 2019 Oregon Legislative Assembly approved a new Corporate Activity Tax effective January 1, 2020. The tax is imposed on the privilege of doing business in Oregon, based on Oregon-sourced commercial activities and is not a transactional tax nor an income tax – it is a modified gross-receipts tax. However, apportionment and tax administration will occur pursuant to existing income tax statues.

The tax is in addition to any other taxes or fees imposed by the State of Oregon and will be imposed at a rate of $250 plus 0.57 percent of taxable commercial activity in excess of $1 million each year. Taxable commercial activity is defined as commercial activity sourced in this state less a subtraction for 35 percent of the greater of "cost inputs" or "labor costs."[39]

Q. Please describe how PGE currently recovers costs of the OCAT.

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[38] PGE/200, Tooman-Batzler/19.
[39] ORS 317A.125 and 317A.119.

A. In Order No. 20-029, the Commission approved PGE's application requesting authorization for deferred accounting beginning on January 1, 2020, and a new tariff, Schedule 131, implementing a rate schedule, balancing account, and automatic adjustment clause for the Oregon Corporate Activity Tax with the condition that the tariff will terminate and the tax will be included in base rates at a future date to be agreed upon by the parties.[40,41]

In Order No 21-030, the Commission approved PGE's application for reauthorization of its deferral for later ratemaking treatment costs for the Oregon Corporate Activities Tax, estimated to be approximately $7.5 million beginning January 1, 2021 through December 31, 2021.[42]

Q. Has additional information regarding the OCAT been provided to Staff?

A. Yes, the Company provided its detailed calculations,[43] as well as providing the following rationale for not including the OCAT in base rates:

- New tax laws, by nature, are untested and provide a lot of uncertainty to taxpayers. Taxpayers rely heavily upon the law's statutes, the Department of Revenue's (DOR) guidance of the statutes, the form's instructions, tax audit outcomes, and litigation to properly file tax returns. However, since PGE's tax return for the initial year of the Oregon Commercial Activity Tax (CAT) will not be filed until October 15, 2021, there have been no tax audits or litigations on which to rely.[44]
- PGE cannot determine the variability of the CAT expense until more returns are filed.[45]

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40 See *In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for Approval of New* Schedule *131, Advice No. 19-25, Oregon Corporate Activity Tax (OCAT) Recovery*, Docket No. UE 368, Order No. 20-029, Jan 29, 2020.

41 See *In* the *Matter of PORTLAND GENERAL ELECTRIC COMPANY Application for Deferred Accounting of Costs Associated with the Oregon Corporate Activities Tax (OCAT), Docket No. UM 2037*, Order No. 20-029, Jan 29, 2020.

42 *Id., Docket No. UM 2037(1), Order No. 21-030, Jan 28, 2021.*

43 Staff/20X, Fox/xx, Response to Staff DR 204 and 205.

44 Staff/20X, Fox/xx, Response to Staff DR 203.a.i.

45 Staff/20x, Fox/xx, Response to Staff DR 203.a.iii.

- Uncertainty begins at the start of the CAT calculation when determining the sourcing of commercial activity (ORS 317A.128) and ensuring that the correct receipts are accounted for. Next, there are more than 40 excluded items (ORS 317A.100(1)(b)), so this determination is critical, but there is, as of yet, no precedent as to what meets the defined items.[46]
- Since the CAT is untested, has no history of audits, and has no litigation precedents, it is impossible to determine what the exact uncertainties are. Therefore, it is unknown what the impact to tax expense would be.[47]
- Based on the uncertainties identified in PGE's response to OPUC Data Request No. 203, PGE has no basis on which to estimate a range of variance that may reasonably occur for the Oregon Corporate Activity Tax.[48]

Q. How much has the Company's estimates of OCAT expense varied?

A. The Company's estimates have been remarkably stable over time. The estimates provided by the Company are:

- UM 2037/UE 368 for 2020 (filed 11/2/19) $7.440,434
- UM 2017(1) reauthorization for 2021 (filed 12/31/20) $7,497,252
- Response to Staff DR 205 (dated 8/12/21)
  - o 2020 $7,471,429
  - o 2021 $7,784,480
- 2020 tax provision detail **[Begin Confidential]** [redacted] **[End Confidential]**[49]

Q. What were Staff and PGE expectations at the time that the initial 2020 deferral was approved?

A. Order No. 20-029 included a succinct statement of Staff's position regarding inclusion in base rates:

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[46] Response to Staff DR 203.b.
[47] *Id.*
[48] Response to Staff DR 559.
[49] Response to AWEC DR 28, UE 394_AWEC DR 028_Attach A_CONF.xlsx.

> In Staff's view, the new OCAT is fundamentally different from the MCBIT in that it is a statewide tax that does not need to be isolated and recovered from a specific subset of the Company's customer base as is required for the MCBIT under OAR 860-022-0045. Also, as noted above, the tax is in addition to any other taxes or fees imposed by the State of Oregon. In other words, from a ratemaking perspective, the OCAT is simply an increase in the overall state tax burden. Accordingly, Staff's position is the OCAT ought to be estimated and rolled into base rates as soon as practicable.[50]

Order No. 20-029 also included the Company's position at the time:

> PGE's estimate of the CAT for 2020 is $7.4 million. However, given that this is a new tax and the ultimate tax amount remains uncertain the actual tax amount may differ. PGE's proposed balancing account and automatic adjustment clause will allow PGE to true up the differences between PGE's estimated CAT collected under Schedule 131 and its actual CAT expense. These differences will be credited or charged to customers through an annual update of Schedule 131 prices.[51]

Q. Please describe the timing of Oregon Department of Revenue (ODR) administrative rulemaking pertaining to administration of the OCAT.

A. Temporary rules were adopted and filed December 30, 2019, effective January 1, 2020 through June 28, 2020. Permanent rules were adopted and filed June 24, 2020, effective June 28, 2020. Staff notes that the 2021 final rules were quite detailed.[52]

Q. Please summarize the Commission's resolution to Staff's proposal to include the OCAT in PacifiCorp's base rates.

A. The Commission declined, stating:

50 Order No. 20-029 at 4.
51 *Id.*
52 https://secure.sos.state.or.us/oard/viewCompDocument.action?compDocRsn=578, pages 774-825.

> We find that the record of this proceeding does not demonstrate that this level of expense is sufficiently certain to include in base rates at this time. Accordingly, we adopt PacifiCorp's request to continue to track and defer the variance between the revenues collected and the actual OCAT expense in the balancing account authorized in Order No. 20-028.[53]

Q. Is PGE situated differently than PacifiCorp was at the time of its most recent general rate case?

A. Yes. Almost another year has elapsed since the Commission issued its order in PacifiCorp's last GRC. October 15, 2021 is the final extended due date for the 2020 CAT return. The return will be filed prior to the conclusion of PGE's rate case. PGE has had a full year longer to digest the meaning and application of the law and administrative rules.

Q. Have the three gas utilities incorporated the OCAT into base rates?

A. Yes.[54]

Q. Why does Staff believe that PGE ought to incorporate the OCAT into base rates at this time?

A. In Staff's view, the Company is simply advocating for the most advantageous financial outcome, namely continuing the extraordinary ratemaking treatment afforded in Order No. 20-029 (dollar for dollar cost recovery via a separate tariff with an automatic adjustment clause).

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53 See *In* the *Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision*, Docket No. UE 374, Order No. 20-473, Dec 18, 2020 at 105-06.

54 See *In* the *Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General* Rate *Revision,* Docket No. UG 388, Order No. 20-364, Oct 16,2020, at 1. See also *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, Request for a General Rate Revision*, Docket No. UG 389, Avista/500, Brandon/34 and Staff/400, Fox/21. See also In the Matter of CASCADE NATURAL GAS CORPORATION, Request for a General Rate Revision, Docket No. UG 390, Order No. 21-001, Jan 06, 2021, at 13.

As discussed above, PGE is either unable or unwilling to quantify the uncertainty surrounding the OCAT. Instead, the Company has offered generalities which amount to suggesting they might be audited. Accordingly, the Commission is unable to consider the risk and materiality of possible harm to PGE if the OCAT were to be included in base rates at this time.

Staff notes that in the 20 months that have elapsed since the Company's initial deferral filing, the estimates of the new law's impact have stayed consistently around $7.4 million for 2020. This is despite significant DOR rulemaking activity during that time. Staff would expect these estimates to be evolving and changing given the level of conceptual uncertainty asserted by the Company, however, the estimates are little changed.

Furthermore, in Staff's view, the Company's position is simply not compatible with the spirit of traditional ratemaking. In a general rate revision, taxes and all other expenses are *estimated* with the inevitable variances absorbed in regulatory lag. In sum, the Company is only citing the novelty of the new law itself, which Staff believes the Commission ought to reject as a basis for continuing extraordinary ratemaking treatment.

Q. What does Staff recommend?

A. Staff recommends that the 2021 estimate of $7.8 million be included in base rates at this time.

CONCLUSION

Q. What are your total proposed adjustments?

A. My proposed adjustments are summarized in the following table.

Adjustment - increase (decrease)	Expense	Plant in Service
Issue 1, P36836: Beaver Modernization		$ (10,172,085)
Issue 2, P36444 Upgrade Excitation System		(350,000)
Issue 3, Incentive Payroll Taxes	(798,229)	(4,399,292)
Issue 4, Oregon Corporate Activity Tax	7,784,480	
Total	$ 6,986,251	$ (14,921,377)

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	John L. Fox
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	I hold a Bachelor of Science degree in Business Administration / Accounting from the University of Oregon (1989). I also completed the Certificate in Public Management program at Willamette University (2010). I have been licensed as a Certified Public Accountant in Oregon since 1991. Maintaining active status has required a minimum of 80 hours continuing professional education every two years.
EXPERIENCE:	From 1989 to 1999 I was in general practice with several CPA firms in Southern Oregon and the Mid-Willamette Valley. My tax experience includes individuals, trusts and estates, qualified retirement plans, and extensive corporate, partnership, and LLC work. Accounting experience during this time includes client write up, compilation and review, and significant audit and attest work. I have been employed in the executive branch of Oregon state government since 1999. My experience prior to joining the Commission staff includes 3 years as a cost accountant, 11 years as a senior budget analyst, and 4 years in an oversight role as a budget team lead. I have extensive experience in capital construction and financing, complex cost modeling, rate development, fiscal projections, expenditure analysis, and cost control for programs with biennial revenues between $100 million and $300 million.
PRIOR DOCKETS:	I have provided testimony as a Staff witness in the following OPUC proceedings; UE 333, UE 335, UE 374, UE 390, UE 391, UG 344, UG 347, UG 366, UG 388, UG 389, UG 390, UM 1992, UM 2004, UM 2026.

CASE: UE 394
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

October 25, 2021

July 19, 2021

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Standard Data Request 080
Dated March 10, 2015

Request:

Please provide a copy of the Company's capitalization policy related to direct costs, Oregon-Allocated Costs, Labor Expense, intangible expense, construction overhead, and labor loading.

a. Please include a copy of all reports and summary of comments regarding the capitalization policy made by the Company's inside and outside auditors.
b. Please provide a detailed narrative, including all necessary calculations, that explains how the Company determines the addition of construction overhead or labor loadings to rate base.

Response:

Attachment 080-A provides a copy of PGE's most recent Cost Allocation Manual describing our cost allocation methods (as filed annually with PGE's Affiliated Interest Report). Attachment 080-B provides the copy of PGE Capital Accounting Policy.

Attachment 080-C provides an excerpt from PGE's Form 10-K filed February 19, 2021, regarding PGE's capitalization policy. Attachment 080-D provides the opinion letter from Deloitte and Touche (D&T), LLP on PGE's Form 10-K financial statements for 2020.

a. PGE is audited annually by D&T, which reviews the accuracy of PGE's financial statements and its compliance with Generally Accepted Accounting Principles. The auditors have not made specific comments, written or otherwise, regarding PGE's capitalization policy (including construction overhead policy), but have consistently found PGE's financial statements in conformity with accounting principles generally accepted in the United States.
b. This information is provided on Pages 8-9 of Attachment 080-B.

Attachment 2

PORTLAND GENERAL ELECTRIC COMPANY

2020 Cost Allocation Manual

per

OAR 860-027-0048(6)

(Reported May 2021)

PORTLAND GENERAL ELECTRIC
COST ALLOCATION MANUAL
FOR THE YEAR 2020

Introduction

This document discusses PGE's loadings, allocations and the respective methodologies that are used to redistribute costs to non-regulated activities and affiliates. For some services, typically those that benefit various functional areas, it is not practicable to charge the cost directly. Costs that cannot be reasonably directly charged are captured either on the balance sheet through deferred accounts or in specific income statement accounts. These costs are then redistributed to their ultimate destination.

PGE uses a series of automated reclassifications and loadings to distribute administrative and overhead costs to end use accounts. There are four groups of these: 1) Labor Loadings, 2) Service Provider Allocations, 3) Administrative Allocations, and 4) Overhead Stores Loadings.

Within the above allocations, numerous costs are distributed to and from Administrative and General (A&G) ledgers, generally FERC accounts 920 and 921. Most A&G costs are not fully allocated. Some A&G accounts are not allocated at all, while others are only allocated in part. With the exception of Paid Time Off (PTO), A&G allocations apply largely to capital and deferred (balance sheet) accounts, and to operations and maintenance (O&M - income statement) accounts in limited circumstances. Consequently, the amounts remaining in A&G represent the unallocated costs related to O&M. The reason for this approach is to comply with FERC reporting requirements (see the Interpretations of Uniform System of Accounts for Electric, Gas and Water Utilities, as revised February 27, 1981). Costs that are applicable to construction work should be directly assigned or allocated to capital. Those that are not related to capital work remain in A&G according to their FERC designation. Note, see the discussion below regarding the exception for Service Provider allocations.

In accordance with FERC, "wherever allocations are necessary in order to arrive at the amount to be included in any accounts, the method and basis of allocation shall be reflected by underlying records" (CFR, Title 18, Pt. 101).

PGE's Non-Regulated Activities

Non-Regulated Activities:

- Large Nonresidential Tradable Renewable Credit Rider (Schedule 54)
- Meter Information Services (Schedule 320)
- Electrical Equipment Services (Schedule 715)

PGE Affiliates and Subsidiaries

Affiliates:

- Portland General Electric Foundation – Corporate foundation of PGE.

Subsidiaries:

- 121 SW Salmon Street Corporation – 121SWS owns the World Trade Center buildings, where PGE has its headquarters. 121SWS charges PGE rent based on PGE's percentage of occupancy of the rentable space in WTC multiplied by WTC operating expenses. PGE charges 121SWS labor costs based on man-hours utilized at fully allocated labor rates. Non-labor items are billed at cost. All profits/losses from 121SWS are retained at 121SWS.

- World Trade Center Northwest Corporation – Inactive except for holding the World Trade Center franchise.

- Salmon Springs Hospitality Group, Inc. – SSHG provides catering within the WTC complex. SSHG charges PGE market rate for catering but discounts the charge for room rental. PGE charges SSHG labor costs based on man-hours utilized at fully allocated labor rates. Non-labor items are billed at cost, with the exception of office space, which is billed at market value. All profits from SSHG flow back to PGE (regulated).

PORTLAND GENERAL ELECTRIC
COST ALLOCATION MANUAL
FOR THE YEAR 2020

Labor Loadings

There are eight categories of labor loadings: 1) Employee support; 2) Payroll Taxes; 3) Employee Benefits; 4) Corporate Incentives; 5) Injuries & Damages; 6) Paid Time Off (PTO); 7) Pension Service Cost; 8) Net Periodic Pension Cost; and 9) Other Post-Retirement Benefits.

For accounting purposes, labor-related costs are classified as A&G costs. These A&G allocations are applied to capital and deferred accounts. O&M accounts receive A&G allocations under certain circumstances, which include non-utility activities, transmission study costs (for billing purposes) and O&M accounts that receive certain Service Provider allocations. In general, labor-related A&G costs are allocated proportionately to the actual direct labor charges in specified Cost Elements (CE), Accounts, Accounting Work Orders (AWO) and Operating Units (representing costs allocable to co-owners). In addition, labor allocated as part of certain Service Provider allocations will be allocated loadings based on the AWO associated with that Service Provider.

Except where indicated below, labor loadings are mostly allocated to straight-time labor charges. The accounting entries created by the loading process are captured in accounts using CEs specific to the loadings.

Employee Support

The Employee Support loading includes the cost of administering PGE’s compensation program, EEO (Equal Employment Opportunity) and employee relations, employee training and development, and Human Resources administration. The costs to be allocated are recorded to A&G accounts 920 (labor) and 921 (non-labor).

Payroll Taxes

The Payroll Tax loading consists of employer-paid, labor-related taxes such as FICA (Social Security & Medicare), federal unemployment, state unemployment, and workers’ compensation premiums. For accounting purposes, these costs are recorded to Taxes Other Than Income Taxes account 408.1. Note: this loading is allocated to premium time and overtime labor charges in addition to straight-time labor charges.

Employee Benefits

The Employee Benefits loading includes the costs of retirement savings, health, dental, disability, life insurance, and education and recreation programs. For accounting purposes, these costs are charged to Employee Pensions and Benefits account 926.

Corporate Incentives

The incentive loading consists of the cost of PGE’s general incentive pay program that is incurred in the Performance Incentive Compensation account (A&G account 920). Costs are not allocated to Coyote Springs, Port Westward, Carty, Biglow Canyon, Tucannon, Boardman, and Pelton/Round Butte because those generating plants have their own incentive programs.

**PORTLAND GENERAL ELECTRIC
COST ALLOCATION MANUAL
FOR THE YEAR 2020**

Injuries & Damages

The Injuries & Damages loading includes the cost of administering PGE's health and safety programs, plus claims from general liability damages, workers' compensation injuries, and auto accidents. Since most injuries and damages occur in fieldwork, the labor basis is reduced by office groups and A&G workers based on labor charges to certain accounts. Consequently, the allocation is weighted to line work and construction. Also, allocated Corporate Governance labor (office groups and A&G labor) is excluded from this labor basis. The costs to be allocated are recorded to Injuries and Damages account 925. Note: this loading is allocated to premium time and overtime labor charges in addition to straight-time labor charges.

Paid Time Off

Paid Time Off (PTO) consists of employee pay for vacation, holiday, sick leave, and funeral leave. Costs for vacation and holiday pay are estimated and accrued while costs for sick and funeral leave are expensed as taken. PTO is the only A&G expense that is fully allocated to balance sheet and income statement accounts. The costs to be allocated are recorded to Employee Pensions and Benefits account 926.

Pension Service Cost

Pension Service Cost is the actuarial estimate of the pension service cost earned by eligible participants. This loading is applied to PGE labor that gets billed to outside parties (i.e., co-owners of PGE's generating facilities and billings jobs) and non-utility activities. The costs to be allocated are recorded to Employee Pensions and Benefits account 926.

Net Periodic Pension Cost

The Net Period Pension Costs (NPPC) loading includes the annual accounting expense associated with the PGE pension plan. The amount of NPPC that is applied to PGE's labor is reduced by the amount of Pension Service Costs billed to outside parties and charged to non-utility activities. The costs to be allocated are recorded to Employee Pensions and Benefits account 926.

Other Post-Retirement Benefits Cost

The Other Post-Retirement Benefits Cost loading includes the annual accounting expense associated with the PGE retiree benefits plan. The amount of the cost that is applied to PGE's labor is reduced by the amount of costs billed to outside parties and charged to non-utility activities. The costs to be allocated are recorded to Employee Pensions and Benefits account 926.

PORTLAND GENERAL ELECTRIC
COST ALLOCATION MANUAL
FOR THE YEAR 2020

Following is a table which includes the actual labor loading rates for 2020:

Labor Loading Rates	2020 Actual Rates	2020 Actual Costs
Employee Support	0.97%	2,493,096
Payroll Taxes	9.97%	28,596,397
Employee Benefits	30.62%	78,657,611
Corporate Incentives	4.98%	11,780,410
Injuries & Damages	5.06%	8,982,275
Vacation (PTO)	16.67%	42,811,515
Pension Service Cost *	6.62%	19,263,527
Net Periodic Pension Cost *	8.07%	
Other Post-Retirement Benefits	0.64%	1,641,154
2020 Actual Total		194,225,985

* Note: Since the pension related loadings share components of pension expense, total pension expense is shown for both loadings in order to calculate total allocable costs.

Service Provider Allocations

Overview

It is not practical or cost-effective to maintain corporate service expertise in each area of PGE. Accordingly, service groups are formed to provide these services to all organizations within the company. PGE has several departments that provide services to most areas of the company. These services include World Trade Center facilities, Information Technology, Production Services, the corporate Helicopter, and Fleet Services. These departments charge their support service expenses to FERC clearing account 184 (excluding WTC) and then the costs are reclassified (or allocated) to the functional areas of the company receiving their services. FERC account 184 serves as the allocation "base" that accumulates costs that are then allocated to those areas receiving the services, or "targets."

Service Provider allocations and the loadings thereon are distributed to various income statement accounts outside of the general rule associated with capital and non-utility accounts and all co-owner accounts. These costs are distributed to reflect the fully allocated cost of the services provided in a manner similar to the results of services provided by a third party. This approach recognizes the full value of the service groups to the user groups and reflects the costs of these services in the income statement line items where the services are used.

World Trade Center Facilities

PGE leases its corporate headquarters office at the World Trade Center (WTC) from 121 SW Salmon Street Corporation (121SWS), a PGE subsidiary. Portions of the WTC are leased to third parties (non-PGE tenants). The WTC Allocation is used to allocate the cost of PGE's corporate headquarters office between PGE (utility and non-utility) and non-PGE tenants.

Costs incurred by 121 SWS to own and operate the building are initially recorded in non-utility accounts (FERC account 418), with the exception of property taxes, which are recorded in FERC account 408.2 Taxes Other Than Income Taxes. Operating costs include base rent, security, general maintenance, cleaning, administration, licenses and fees, utilities, property taxes, insurance, depreciation, and uncollectible accounts.

Allocation of costs to PGE is based on PGE's percentage of occupancy of the rentable space in the WTC buildings. The amount allocated to PGE is then apportioned by functional areas of PGE, including O&M, A&G, Capital and non-utility accounts using fixed rates. These rates are calculated based on budgeted labor headcount (including contract labor) in departments that occupy space at WTC. Each employee working at the WTC is assigned an equal weight as all employees are assumed to consume an equal amount of space and costs, which are then assigned to functional areas based on the accounts used by the departmental budgeted labor. Amounts related to functional areas in PGE utility operations are allocated above the line to various O&M expense accounts. Amounts related to functional areas in PGE non-utility operations are allocated to non-utility expense accounts.

PORTLAND GENERAL ELECTRIC
COST ALLOCATION MANUAL
FOR THE YEAR 2020

Operating costs which are identifiable to specific utility or non-utility operations are directly allocated.

WTC Cost Distribution (Actual)	
PGE (Utility/Non-Utility Tenants)	67.14%
Non-PGE Tenants	32.86%
Total Cost Pool	$ 12,691,843
PGE's Share allocated	$ 8,521,304

Below is a table of the actual distribution percentages of the 2020 WTC costs allocated to PGE:

World Trade Center Allocation	**% Lease Cost**
Boardman	0.27%
Coyote Springs	0.00%
Pelton	0.28%
Round Butte	0.25%
Utility Capital	8.45%
Trojan	0.24%
Utility Expense	89.32%
Non-Utility	1.19%
2020 Actual Total	**100.00%**

Information Technology

PGE’s Information Technology (IT) department provides services to all functional areas of the company in the following ways:

- Provides operational and developmental support to end-user applications systems (software);
- Develops, operates and maintains computer systems and telecommunication equipment; and
- Manages the overall direction for information system and technology issues.

The allocation of these costs, which initially post to FERC account 184, is done via fixed rates, which are based on the relative percentage of budgeted labor hours (straight-time and contract labor for most areas) of the receivers of IT services. The overall allocation to Generation (including Power Operations) is further allocated to each generating facility and Power Operations based on the number of computers assigned.

PORTLAND GENERAL ELECTRIC COST ALLOCATION MANUAL FOR THE YEAR 2020

Production Services

The Production Services portion of Service Providers includes the Printing and Mail Services group, whose primary mission is to ensure PGE's retail revenue invoices are printed, inserted and mailed timely and completely in a cost-effective manner. They also provide a variety of other business services including CD/DVD production, engraving, copying, inserter sorting, bindery, and mailing services.

Costs are initially charged to FERC account 184 then certain service requests are manually allocated to the user (requesting) department. The remaining balance is allocated based on fixed percentages to various functional areas/end use accounts. The Printing and Mail Services group tracks the volume of services to end-users (historical usage), which is used to calculate the fixed percentages. Unless there is a significant change in the end-users of the services, the percentages usually remain the same from the prior year.

Helicopter

The costs to operate the corporate helicopter (operations, maintenance, and depreciation) are charged to FERC account 184. While the helicopter is used primarily for transmission and distribution power line inspections and surveillance, usage charged to A&G includes environmental, wildlife, vegetation, and project surveys. The helicopter costs are allocated via fixed percentages based on historical usage patterns. Unless this is a significant change in the usage patterns, the percentages usually remain the same from the prior year.

Included below is a table which lists the 2020 actual percentages and costs for the Service Provider Allocations:

	Information Technology	**Production Services**	**Helicopter**
Trojan	0.73%	0.10%	N/A
Boardman	2.24%	0.25%	N/A
Coyote Springs	0.85%	0.15%	N/A
Pelton / Round Butte	1.43%	0.40%	N/A
Generation [1]	10.71%	1.65%	N/A
Power Operations	2.93%	1.00%	N/A
Transmission	2.80%	7.00%	30.00%
Distribution	39.09%	15.50%	20.00%
Marketing	3.17%	2.25%	N/A
Customer Service	16.22%	32.00%	N/A
Admin & General	18.47%	38.00%	50.00%
Non-Utility	1.36%	1.70%	N/A
Totals	**100.00%**	**100.00%**	**100.00%**
2020 Actual Total	**$57,768,106**	**$433,279**	**$518,168**

[1] Generation includes Beaver, Faraday, North Fork, Oak Grove, River Mill, Sullivan, Port Westward, Port Westward 2, Carty, Biglow, and Tucannon.

**PORTLAND GENERAL ELECTRIC
COST ALLOCATION MANUAL
FOR THE YEAR 2020**

Fleet Services Overview

PGE manages a fleet of vehicles and specialized equipment to support the wide variety of activities necessary to operate the company. The majority of these vehicles are dedicated to the work of PGE's line crews (Transmission and Distribution – T&D). In addition, PGE maintains a small pool of light-duty pickups and passenger vehicles which support employee transportation job requirements. The fleet is segregated into nine vehicle types:

Type 1 - Man-lift equipment
Type 2 - Digger derrick equipment
Type 3 - Cranes
Type 4 - Heavy-duty trucks
Type 5 - Medium-duty trucks
Type 6 - Light-duty trucks
Type 7 - Construction equipment
Type 8 - Trailers

Rates are determined for each vehicle class by analyzing historical cost and usage levels through periodic cost studies.

Fleet related costs are initially charged to FERC account 184. Out of this cost pool, non-T&D assigned vehicles are allocated a fixed monthly amount based on the type of vehicle assigned and the latest vehicle study rate and normalized usage. The remaining cost pool is then allocated to T&D departments with assigned vehicles based on their labor costs.

Vehicles assigned to generation plants are generally excluded from the fleet allocation since the generating plants incur the overhead costs (maintenance, fuel, etc.) for their assigned vehicles, either at the generating plant or at the mini-fleet shop maintained at Faraday. Accordingly, generation assigned vehicles are reviewed for possible inclusion but generally are not allocated costs.

The actual rates for Type 1-8 vehicles used during 2020 are included in the following table:

Transportation Rates	**Hourly Rate**
Type 1 - Man-lift Equipment	$38.67
Type 2 - Digger Derrick Equipment	$80.82
Type 3 - Cranes	$71.77
Type 4 - Heavy Duty Trucks	$95.68
Type 5 - Medium Duty Trucks	$27.06
Type 6 - Light Duty Trucks	$12.80
Type 7 - Construction Equipment	$28.64
Type 8 - Trailers	$12.75

Actual costs associated with operating and maintaining the company vehicle fleet for 2020 total $15,961,615.

PORTLAND GENERAL ELECTRIC COST ALLOCATION MANUAL FOR THE YEAR 2020

Administrative Allocations

Corporate Governance

Certain A&G costs are distributed to PGE's capital, non-utility and the co-owned entities through the Corporate Governance allocation. These costs are incurred for activities such as Human Resources, Accounting, and other corporate functions that support all PGE activities. This is accomplished by pooling the corporate governance costs and allocating them to PGE capital, non-utility, billings jobs, and the co-owned entities capital and A&G accounts.

Activities charged to certain A&G accounts (FERC 920: allocable labor; 921: allocable non-labor; and 923: allocable outside services) and by certain departments have been identified as supporting all PGE, including the generating plant co-owners. The charges in these ledger segments are pooled together creating the "Corporate Governance Cost Pool". Certain departments, however, are excluded from the Cost Pool since their activities do not support the co-owners, such as tax and legal, as well as officer departments.

The basis for this allocation is a comparison of all labor costs for PGE and the co-owned entities (excluding PTO). For PGE, the allocation is made to capital, billing jobs, and non-utility activity and also when related to certain Service Provider allocations. Costs remaining in A&G reflect amounts that are unallocated to PGE's O&M expenses. For the co-owned entities, however, costs are distributed to capital, A&G, and decommissioning.

Included below is a table which shows the 2020 actual percentages and costs for the Corporate Governance Allocation:

Corporate Governance

	Capital	Decommissioning	Expense
Trojan	0.00%	0.81%	0.02%
Boardman	0.40%	N/A	2.74%
Pelton	0.15%	N/A	0.99%
Round Butte	0.29%	N/A	0.10%
Coyote Springs	0.06%	N/A	1.36%
Utility	39.48%	N/A	52.71%
Non-Utility	0.00%	N/A	0.54%
KB Pipeline	0.00%	N/A	0.04%
Affiliates	N/A	N/A	0.31%
Totals	**40.38%**	**0.81%**	**58.81%**
2020 Actual Total	$21,554,831		

Corporate Allocation Summary

The pool of allocable dollars in 2020 related to Labor Loadings, Service Provider Allocations, and Corporate Governance, all of which were discussed above, totaled $298,983,192 of which $216,881,551 was allocated to capital, non-utility and other expenses. The below table provides a summary of the allocation targets. All unallocated dollars remain in their respective A&G or O&M accounts.

2020 Corporate Allocation Summary	
Trojan	0.93%
Boardman	2.98%
Pelton	1.12%
Round Butte	1.09%
Coyote Springs	1.14%
KB Pipeline	0.04%
Utility Capital	39.78%
Utility Expense	51.75%
Non-Utility	0.80%
Affiliates	0.37%
Total	**100.00%**

Affiliate Billings

The affiliate billings include labor loadings plus the allocations (Corporate Governance, WTC Floor Space and Service Provider costs). The direct costs incurred to provide services (i.e. labor costs) are accumulated in a billing job account (FERC account 186 Miscellaneous Deferred Debits) along with the associated loadings and allocations. These costs are then billed to each affiliate and the billing job is relieved. If any balance remains in the billing job account, these costs are cleared to a non-utility account.

Other Utility Administrative Allocations

PGE has other administrative allocations that are intra-company allocations and stay within utility operations; these include:

- Distribution Operations Supervision Engineering
- PSES Administrative Overhead Allocation
- Construction Loadings (allocation of administrative costs to utility capital)

These allocations do not impact affiliate, non-utility or subsidiary activities.

**PORTLAND GENERAL ELECTRIC
COST ALLOCATION MANUAL
FOR THE YEAR 2020**

Stores Loadings

Overview

PGE uses two stores loading rates: Boardman and PGE general inventory. The Boardman rate applies only to the operating trust; the PGE general inventory rate is applied to all other stores issues and returns.

PGE General Inventory

The Stores loading (also referred to as the materials loading) is used to spread the cost of operating and maintaining material storerooms to the accounts that receive materials issues.

The costs incurred to operate each storeroom relate to both the maintenance of items in inventory and issuance of inventory to end-users. The balance remaining in stores overhead has a parallel relationship to the balance in stores inventory, so as the level of inventory increases, so would the balance in stores overhead. The calculation of the loading rate utilizes a 2-year rolling average of gross purchases, issues and returns divided into a 2-year rolling average of the operating costs. This ratio, multiplied by the dollar value of the physical inventory at a given point in time, determines the net amount of dollars that will remain in the stores overhead account (account 163). The stores loading process and manual adjustments keep the overhead balance at the appropriate level.

The 2020 loading rates are as follows:

PGE Materials	19%
Boardman	23%

August 12, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 203
Dated July 29, 2021

Request:

Regarding the Q&A on PGE/200, Tooman-Batzler/19:

a. Please provide a detailed narrative explanation of the remaining uncertainties listed below. Please provides citations to all related Oregon Revised Statutes and Oregon Administrative Rules pertaining to each uncertainty;

    i. Needs additional time to evaluate how the tax operates.

    ii. How much expense it will generate?

    iii. How much variability it will entail?

b. Staff's understanding is October 15, 2021 is the final extended due date for the 2020 CAT return. Please explain what uncertainties the Company anticipates will be unresolved at that date and provide dollar range for each.

Response:

a.

i. New tax laws, by nature, are untested and provide a lot of uncertainty to taxpayers. Taxpayers rely heavily upon the law's statutes, the Department of Revenue's (DOR) guidance of the statutes, the form's instructions, tax audit outcomes, and litigation to properly file tax returns. However, since PGE's tax return for the initial year of the Oregon Commercial Activity Tax (CAT) will not be filed until October 15, 2021 there have been no tax audits or litigations on which to rely.

ii. PGE estimates the 2020 expense to be approximately $7.5 million. For details, see PGE's response to OPUC Data Request No. 205, Confidential Attachment A.

iii. PGE cannot determine the variability of the CAT expense until more returns are filed.

b. The CAT, as described by the DOR:

The CAT is imposed on businesses for the privilege of doing business in this state. It is measured on a business's commercial activity, which is the total amount a business realizes from transactions and activity in Oregon. Certain items are excluded from the definition of *commercial activity and, therefore, will not be subject to the CAT. In addition, Oregon's CAT allows a 35 percent subtraction for certain business expenses.*

Uncertainty begins at the start of the CAT calculation when determining the sourcing of commercial activity (ORS 317A.128) and ensuring that the correct receipts are accounted for. Next, there are more than 40 excluded items (ORS 317A.100(1)(b)), so this determination is critical, but there is, as yet, no precedent as to what meets the defined items.

Since the CAT is untested, has no history of audits, and has no litigation precedents, it is impossible to determine what the exact uncertainties are. Therefore, it is unknown what the impact to tax expense would be.

August 12, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 204
Dated July 27, 2021

Request:

Please provide all work papers and calculations related to quarterly estimated tax payments for the 2020 and 2021 CAT through the second quarter. Please provide the same information for the 2021 third and fourth quarters as it becomes available. This is a standing request.

Response:

Attachments 204-A through 204-F provide the requested quarterly estimated CAT payment work papers from Q1 2020 to Q2 2021.

Attachments 204-A through 204-F contain protected information subject to General Protective Order No. 21-206.

August 12, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 205
Dated July 29, 2021

Request:

Regarding the work paper Exhibit Support 2022.xlsx, Other Tax Data tab, please provide all work papers underlying the CAT figures shown ($6,870,698 and $7,784,480 for 2020 and 2021, respectively).

Response:

Attachments 205-A and 205-B provide the requested 2020 CAT provision and 2021 budget work papers. The correct amount for 2020 is $7,471,429 and will be provided in updated Exhibit Support work papers.

Attachments 205-A and 204-B contain protected information subject to Protective Order No. 21-206.

August 19, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 269
Dated August 5, 2021

Request:

Regarding the Company's response to Staff Data Request 142 and the project P36444 Upgrade Excitation System:

a. Please state if any portion of the project is included in rate base at April 30, 2022.

b. Please explain what would be the outcome if PGE did not comply with the "new WECC regulations".

Response:

a. Approximately $350,000 of capital costs associated with project planning activities are included in PGE's rate base at April 30, 2022.

b. All North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) regulations and reliability standards are established and enforced to ensure the effective and efficient reduction of risks to the reliability and security of the grid. Failure to follow these regulations and standards may: 1) increase or fail to reduce risks to the reliability and security of the grid; and 2) subject PGE to significant financial penalties and corrective actions, which yield additional financial penalties, if not completed.

August 19, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 276
Dated August 5, 2021

Request:

Regarding the Company's response to Staff Data Request 143 and the project P36836 BR: Beaver Modernization:

a. Please confirm that the cost of this project is included in rate base in this case.

b. Please explain how conversion from a dual fuel to single fuel system will "allow for greater operationally flexibility".

Response:

a. Yes. At the time of the UE 394 filing PGE was expecting the project to be placed in service prior to April 30, 2022. As such, the cost of the project is currently included in the rate base for this case. More recent information reflects an in-service date of June 2022 which means that, if the project timeline does not move back to a completion in April of 2022, PGE will remove the cost of the project from the 2022 rate base in a subsequent revenue requirement update.

b. PGE has a commitment to Department of Environmental Quality (DEQ) to reduce annual allowable emissions of regional haze pollutants at Beaver. The planned combustion upgrades will significantly reduce the hourly emissions and so, in the context of that commitment, allow for greater operational flexibility while remaining below the reduced annual allowable emissions.

August 19, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 288
Dated August 5, 2021

Request:

Regarding PGE/200, Tooman-Batzler/23, Exhibit 206, and Exhibit 302, Staff calculates the ratio of payroll taxes/aggregate wages to be 7.70%, 7.96%, 7.91%, 8.74%, and 8.71% for 2018-2022, respectively:

a. Please explain why, in aggregate, payroll taxes are increasing while wages decrease comparing 2020 through 2022.

b. Please explain why the Company cites "an approximate 8.0% payroll tax rate to total wages" in testimony which does not appear to match the Staff calculated figures above.

Response:

a. As we discuss in PGE Exhibit 300, Section III, "[t]o provide a more accurate reflection of our total labor and to better align with how labor is viewed, planned for, and controlled internally, we define total labor as both PGE labor and contract labor."[1] As such, PGE Exhibit 302 contains certain cost elements (i.e., 1502: Non-PGE Labor Straight Time and 1602: Non-PGE Labor Overtime) for which PGE does not incur payroll taxes. Additionally, PGE does incur payroll taxes on Performance Incentive Compensation and Annual Cash Incentive amounts paid to employees, which are not included in PGE Exhibit 302. Finally, while not material, PGE forecasts payroll taxes using only direct charges and not allocated cost elements. When including incentive costs and, more importantly, when removing cost elements 1502 and 1602, PGE's labor costs do increase slightly from 2020 to 2022, leading to the slight increase in payroll taxes over the same period.

b. See part (a). When making these adjustments, PGE's calculated ratio for 2018-2022 is as follows: 8.4%, 8.5%, 8.1%, 8.1%, and 8.1%.

[1] PGE Exhibit 300, page 13, lines 8-10.

September 8, 2021

To: Kathy Zarate
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 559
Dated August 25, 2021

Request:

Regarding the Company's response to Staff Data Request 203 and the revised $7.5 million expense estimate therein, please provide the range of variance the Company expects may reasonably occur as a result of the uncertainties listed in section a.(i) of the response.

Response:

Based on the uncertainties identified in PGE's response to OPUC Data Request No. 203, PGE has no basis on which to estimate a range of variance that may reasonably occur for the Oregon Corporate Activity Tax.

September 8, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 563
Dated August 25, 2021

Request:

Regarding the Company's response to Staff DR 269:

a. Please provide a list of all projects in Attachment 143-A for which preliminary costs are being included in rate base as of April 2022 and the project itself is not yet in service.

b. For each project listed in this response, please provide a narrative description of the cost and amount.

Response:

There are no other projects listed in Attachment 143-A for which preliminary costs are included in PGE's UE 394 rate base but the project itself is not yet in service.

September 8, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 570
Dated August 25, 2021

Request:

Regarding the Company's response to Staff DR 288, and the discussion in the August 23rd workshop regarding payroll taxes and incentives, please provide the amount of payroll taxes attributable to the Performance Incentive Compensation and Annual Cash Incentive amounts expense removed from the case in the Company's initial filing.

Response:

The following table provides the requested information. Column two provides the amount of incentive-related payroll taxes currently included in PGE's request. Column three provides the amount of incentive-related payroll taxes attributable to incentive amounts PGE voluntarily removed from our test year request.

Account (1)	**Amount Based on 100% Incentives Forecast (2)**	**Amount Attributable to 100% Officer Incentives and 50% Non-Officer Incentives (3)**
4081004: Payroll Taxes - FICA	2,545,381.75	1,397,746.26
4081009: AllocCredit - Payroll Tax	(1,174,164.28)	(644,769.19)

September 28, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 766
Dated September 14, 2021

Request:

In UE 335, for final revenue requirements purposes, please provide the overall split for labor (including contract labor), including overheads, between expense and capital.

Response:

PGE did not rely on an overall labor split for purposes of calculating a final revenue requirement in Docket No. UE 335. In PGE's response to OPUC Standard Data Request No. 093 for UE 335, PGE provided a breakout between O&M and rate base for 2019 forecast labor cost as 68.3% - O&M and 31.7% - Capital. However, this split did not include contract labor. Reviewing 2019 actual labor data as provided in PGE's FERC Form 1, pages 354-355, PGE's O&M and Capital labor split is calculated as 62.43% - O&M and 37.57% - Capital. This also does not include contract labor. Attachment 766-A provides this calculation.

Labor Allocations between O&M / Capital / Other
All Data Based on FERC Form 1, pages 354-355

	2019	Percent	Percent O&M and Capital Only
O&M Labor	$ 198,153,023	61.03%	62.43%
Construction	$ 118,751,245		
Plant Removal	$ 506,180		
Capitalized EE			
Total	$ 119,257,425	36.73%	37.57%
Other Accounts	$ 12,791,801		
less Partnership Share	$ (5,507,806)		
less Capitalized EE			
Total	$ 7,283,995	2.24%	0.00%
PGE Share Total	$ 324,694,443	100.00%	100.00%
Reconcile:			
Total Labor	$ 330,202,249		
less Partnership Share	$ (5,507,806)		
PGE Share Total	$ 324,694,443		
	Match		

September 28, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 767
Dated September 14, 2021

Request:

Regarding the Company's response to Staff data requests #288 b. and #570,

a. Regarding the statement "When making these adjustments, PGE's calculated ratio for 2018-2022 is as follows: 8.4%, 8.5%, 8.1%, 8.1%, and 8.1%", please provide the reconciliation underlying the calculated ratios.
b. Regarding the table provided in response to data request #570, please reconcile those numbers to the response to item a. above.
c. Please provide a detailed narrative explanation of how the payroll taxes attributable to the incentive adjustment have been removed from this case.

Response:

a. Upon a review of the data used, the ratios cited above and included in PGE's response to OPUC Data Request No. 288 were calculated using an incorrect incentive amount. Correcting for this, calculates a 2018-2022 ratio as follows: 8.5%, 8.7%, 8.3%, 8.3%, and 8.3%. Attachment 767-A provides the correct data used in calculating these ratios.
b. The amount cited in PGE's response to OPUC Data Request No. 570 and included as part of PGE's account 4081004, 2022 forecast was calculated using a forecast incentive amount of $33,272,964, multiplied against the standard Internal Revenue Services (IRS) Federal Insurance Contributions Act (FICA) tax rate for incentive pay of 7.65%. The credit amount in account 4081009 was ratably calculated for purposes of PGE's response to OPUC Data Request No. 570 by multiplying the gross incentive-based amount of payroll tax (i.e., $2,545,381.75) against the ratio of allocated payroll tax to gross payroll tax (i.e., -$14,131,079/$30,633,694).

   The amounts attributable to the 100% Officer Incentives and 50% Non-Officer Incentives PGE voluntarily removed from our test year request were calculated using the ratio of incentives voluntarily removed from our case that are included in incentive accounts 9200005, 9200006, 9200008, and 9200013.

   Attachment 767-A provides similar calculations as those described above, using PGE's filed incentives forecast, which is slightly different than the amount used when developing PGE's payroll tax forecast for 2022 ($33,233,906 filed vs. $33,272,964).
c. The payroll taxes attributable to PGE's voluntarily removal of incentives were not removed from PGE's initial filing.

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 811
Dated September 17, 2021

Request:

In Docket No. UE 335 Staff expressed concerns that "PGE allocates costs to affiliates for services such as information technology and printing, and bills labor at cost."[1]

Staff further states that "PGE's cost allocation manual identifies a method of calculating the cost of shared services provided to affiliates and non-utility operations. The manual further states that affiliates are billed for allocated costs. This suggests that PGE does not evaluate the market value of services provided to affiliates."[2]

a. Please confirm or deny Staff's representation of PGE's allocation of costs to affiliates in Docket No. UE 335.
b. If section "a" is denied, please provide an explanation in the Company's own words of how, in 2018, the fair market value of transactions was considered in allocating costs to affiliates.
c. Please provide an explanation in the Company's own words of how the market value of transactions is considered when forecasting costs allocated to affiliates in the 2022 test year.
d. Please indicate whether the Company's Cost Allocation Manual, or other relevant policies or procedures have changed since 2018.
e. If yes to section "d," please provide an explanation of the changes made, with particular detail given to how such changes insure the Company is compliant with OAR 860-027-0048(4)(d) and (e).

Response:

a. PGE does not agree with Staff's UE 335 representation. The costs charged between PGE and its affiliates are appropriate based on the following:
    - PGE's charges to affiliates are based on the Master Service Agreement (MSA) as initially approved by Commission Order No. 06-250 (Docket No. UI 248).
    - The variety of services covered by the MSA (e.g., office support, business analysis, finance and treasury support, purchasing) are not available from a

[1] Docket No. UE 335, Staff/800, Kaufmann/7, lines 17 and 18.

[2] Docket No. UE 335, Staff/800, Kaufmann/8, lines 17 and 20.

market source that can be compared to PGE's cost. Consequently, PGE charges fully loaded, fully allocated costs to its affiliates to include all applicable labor-related costs and support services.

- Details regarding PGE's loadings and overhead cost allocations which are applied to PGE's MSA labor have been provided with PGE's annual affiliated interest (AI) report since 2004. On September 27, 2004, Staff issued its Audit of PGE's 2003 Annual Affiliated Interest Report and stated that "Pursuant to OAR 860-027-0048, PGE provided a Cost Allocation Manual (CAM) as an attachment to the AI Report. Staff reviewed the content and format of the CAM and believes that PGE has adequately addressed its cost allocation methods." Although PGE replaced its financial system in 2012, it did not significantly alter the method of calculating its loadings and allocations then or since. Instead, we revise the rates based on updated costs from year to year and occasionally revise the cost criteria based on changing conditions.
- Services from Salmon Springs Hospitality Group (SSHG) to PGE have been discounted to market price and SSHG profit has been credited to PGE customers through Other Revenue.
- Costs from 121 SW Salmon Street Corporation to PGE are based on the agreement approved by Commission Order No. 18-323.

b. See PGE's response to Part a, above.

c. See PGE's response to Part a, above.

d. No. See PGE's response to Part a, above.

e. See PGE's response to Part d, above.

August 24, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 028
Dated August 11, 2021

Request:

Please provide copies of PGE's tax provision calculation for calendar year 2020.

Response:

Attachment 028-A provides the requested information.

Attachment 028-A contains protected information subject to Protective Order No. 21-206.

CASE: UE 394
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Heather Cohen. I am a Senior Utility Analyst employed in the Rates, Finance and Accounting Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. I provide background, analysis, and recommendations regarding the Company's Test Year expense for wages, salary, incentives, and full-time equivalents. I also address Staff's adjustments to the Company's Test Year expense for uncollectibles, customer accounts, advertising and promotional activities, and Human Resources/Employee Support budgets.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. COMPENSATION

Q. Please provide a summary of the Commission's historical method for determining the amount to include in a utility's revenue requirement for wages, salaries, incentives, and overtime expense.

A. The Commission's methodology has many components. The Commission determines the appropriate level of wages and salaries for employees in the Test Year using its three-year wage and salary (W&S) model to estimate union and non-union payroll levels for energy utilities.[1,2] The model determines an appropriate level Test Year expense and capital investment for wages and salaries by escalating the Company's base year wages and salaries by annual changes to the All Urban CPI and applying a sharing mechanism between the wages and salaries determined by the W&S model and the wages and salaries proposed by the utility.

To determine the appropriate amount to include in revenue requirement for incentives paid to employees, the Commission's policy is to disallow 100 percent of officers' bonuses because they are typically based on increased earnings, which benefits shareholders.[3] It is also Commission policy to disallow 75 percent of performance-based bonuses because they are

[1] *In the Matter of Northwest Natural*, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999), *In the Manner of PacifiCorp,* Docket No. UE 375, Order No. 20-473 at 102 (December 18 2020).

[2] See *Pacific Power & Light,* UE 116, Order No. 01-787 at 40; In the Matter of Northwest Natural, Docket No. UG 132, Order No. 99-697 at 43 (November 12, 1999); *In the Matter of PGE*, Docket No. UE 102, Order No. 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, Docket No. UE 88, Order No. 95-322 at 10 (March 29, 1995).

[3] See Order No. 99-033 at 62; and *In the Matter of the Application of US West*, Docket No. UT 125, Order No. *97*-171 at 74-76 (May 19, 1997).

generally focused on increased earnings and therefore bring more benefit to shareholders. The Commission disallows 50 percent of merit-based bonuses because they equally benefit shareholders and ratepayers. Union bonuses are treated in the same manner as non-union bonuses.[4]

Finally, the Commission determines the appropriate ratio of expense and capital to apply to the total forecasted compensation and applies it to determine what compensation expense that is included in Test Year expense and what compensation is included rate base.

Q. Please explain how Staff used the Three-Year W&S model to arrive at its recommendation for wage and salary levels for the Test Year.

A. As a starting point for determining non-union wages for each employee class, the W&S model uses the utility's actual wage, salary, and overtime levels as they existed three years prior to the Test Year.[5] For example, a 2022 Test Year would require a Base Year of 2019. From there, the Base Year wages and salaries are adjusted by a year over year escalation of expenses using the All-Urban CPI for each of the three subsequent years to establish a forecast of Test Year wage and salary levels.[6]

In effect, the model calculates the average salary based on the Company’s actual Base Year calendar payroll (2019), divided by the actual Base Year FTE (2019), then escalates the average by the annual changes to the All-Urban CPI. Once the escalated amount is determined, it is compared to

4 See Order No. 20-473 at 97; Order No. 99-697 at 44-45; Order No. 99-033 at 62.
5 See Order No. 99-*697* at 43.
6 *Ibid.*

the Company's Test Year figures.[7] At this point the sharing principle is applied, wherein Staff adjusts its forecasted amount to allow the Company to share 50/50 the lesser of the difference between the model forecast and the amount the Company has included in its Test Year or a 10 percent band around Staff's projection.[8]

For non-union wages, the W&S model incorporates actual market-based data by using historic wages and adjusting for inflation using the All-Urban CPI index.[9] The Commission has consistently validated the All-Urban CPI to adjust historic wages and salaries as "adjusting payroll levels by changes in inflation provides employees the same real level of compensation as in the base year and provides an incentive to companies to minimize labor costs."[10] Moreover, the All-Urban CPI captures local economic conditions as the Bureau of Labor Statistics includes Oregon prices in its survey.[11] Further, the methodology of equally dividing between ratepayers and shareholders the difference between the utility's Test Year forecast and the forecast obtained by the model allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.[12]

For union wages, the W&S model again starts with actual wages three years before the Test Year. Rather than escalating the wages using All-Urban

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[7] *Ibid*.
[8] *Ibid*.
[9] *Ibid.*
[10] *Ibid.*
[11] *Ibid.*
[12] Order No. 95-322 at 10.

CPI, wages are escalated using negotiated wage increases as set forth in union contracts and Staff's final adjustment incorporates any sharing between the Company's Test Year forecast and the forecast obtained under the W&S model.[13] In its 2020 order in PacifiCorp's general rate case, the Commission rejected Staff's proposed 50/50 sharing between Staff's Test Year determination of expense for union wages and salaries and the Company's, concluding that the arms-length nature of the negotiations regarding wages was sufficient protection for ratepayers.[14]

Q. Why has the Commission used the W&S model to determine Test Year expense for non-union wages and salaries?

A. The Commission has explained its rationale in previous orders. For example, in an order issued in 1999, the Commission explained:

> The [Three Year] model incorporates actual market-based data by using, as a starting point, actual historic wages. We also agree with Staff's use of the All Urban CPI index to adjust historic wages and salaries. Adjusting payroll levels by changes in inflation provides the employees the same real level of compensation as in the base year, and provides an incentive to companies to minimize labor costs. Contrary to the assertions by NW Natural, local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey. Moreover, Staff's method of sharing the difference between payroll projections equally between ratepayers and shareholders also allows NW Natural some ability to increase wages above the rate of inflation in response to changes in market conditions without allowing unchecked escalation.[15]

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13 See Order No. 99-697 at 43.
14 Order No. 20-473 at 94.
15 *Ibid.*

Q. Please summarize Company's proposal for wages, salaries, incentives and overtime expense in this case.

A. The Company's 2022 Test Year includes $351.7 million in wages and salaries (base pay), $18.6 million in incentive compensation, and $19.3 million in overtime.16 The Oregon allocation factor is 100 percent with a 63.3/36.7 percent split for O&M and Capital.17 The Company claims to have removed all incentive compensation paid to the executive group as well as 50 percent of non-officer incentives based on 2020 actuals, a reduction of $10.6 million, as illustrated below.[18]

FIGURE 1. TOTAL INCENTIVES AS PER PGE

Table 4
Total Incentives ($000)

Incentive Plans	2020 Actuals	2022 Test Year[(1)]
Performance Incentive Compensation	$8,567	$9,842
Annual Cash Incentive	$9,547	$5,141
Stock (long-term incentive plan)	$10,887	$3,437
One-time recognition and Miscellaneous	$133	$146
Total Incentives[(2)]	$29,133	$18,566

(1) *Amounts are net of PGE's pre-filing adjustments.*
(2) *Numbers may not sum due to rounding.*

The Company states there are no Officer incentives capitalized in plant costs from 2016 to 2020.[19]

Q. How does the Company determine the compensation for employees?

16 Staff/302, Cohen/2, PGE's Response to Staff DR No. 92 Attach A (electronic spreadsheet).
17 Staff/302, Cohen/3, PGE's Response to Staff DR No. 93.
18 PGE/300, Mersereau – Neitzke/2, 21.
19 Staff/302, Cohen/14, PGE's Response to Staff DR No. 493.

A. PGE testifies that it compares its wages and salaries to relevant markets using compensation surveys via third-party consulting companies. The Company uses these data points to benchmark the salaries of positions and roles against similar PGE positions, determining a midpoint for each compensation grade within the pay structure. Pay ranges are then established around the midpoint and actual salaries for each position level must fall within a specific range of PGE's pay structure as determined by these mid-points. Pay above or below the median may still occur based on experience, scope, and impact of the role.[20] In 2020, the Company adjusted the midpoints of its pay structure to align with the market.[21]

In terms of incentives, the Company offers four types:

- The Performance Incentive Plan (PIC), which rewards eligible (non-represented) employees with cash payments for performance tied to results;
- Annual Cash Incentive (ACI) Plan, which offers payouts to executives and key non-bargaining employees tied to several goals such as Corporate Strategy, Customer Satisfaction, Electric Service Power Quality and Reliability, and Generation Availability and Financial Performance;

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20 PGE/300, Mersereau – Neitzke/15.
21 PGE/300, Mersereau – Neitzke/16.

- Long-Term Stock Incentive Program, which provides directors, officers, and key employees with long-term incentives paid out in three-year cycles; and
- One-time recognition and Miscellaneous, which provides employees individualized cash rewards based on exceptional performance.[22]

Q. What adjustments did the Company make to its actual 2020 Base Year salaries and wages to forecast the 2022 Test Year?

A. The Company escalates its 2020 Base Year pay of non-union employees by 2.5 percent in 2021 and 3 percent in 2022. For union wages and salaries, PGE started with a 2020 Base Year and applied a rate of 3.5 percent for 2021 and 2022 based on expected collective bargaining increases for the Company's two unions in IBEW Local No. 125.[23] PGE has also reduced its Test Year O&M expenses by $10 million to account for vacancies or unfilled positions.[24]

<u>Wages, Salary, and Overtime</u>

Q. What is Staff's recommendation for Test Year wages and salary including and overtime?

A. As previously stated, PGE escalated its Base Year 2020 non-union wages and salaries by 2.5 percent and 3 percent for 2021 and 2022 while using rates of 3.5 percent to escalate its union wages and salaries for 2021 and 2022.[25] Staff, consistent with the W&S model, starts with a Base Year that is three

22 PGE/300, Mersereau – Neitzke/22-25.
23 PGE/300, Mersereau – Neitzke/18.
24 PGE/300, Mersereau – Neitzke/19.
25 PGE/300, Mersereau – Neitzke/18.

years prior to the Test Year (2019), and escalated to the Test Year using All-Urban CPI (CPI) rates, which are 1.2 percent for 2020, 3.7 percent for 2021, and 2.4 percent for 2022.[26] Staff escalated union salaries and wages in the same manner as the Company, applying a rate of 3.5 percent for 2021 and 2022 based on expected collective bargaining increases.[27]

Staff then applied the sharing principle to its and the Company's projected 2022 test year amounts. The sharing principle, which allows the Company to share 50/50 the lesser of the difference between the Company's and Staff's calculated projections, or a 10 percent band around Staff's calculated projection, makes a reduction to Staff's projection. Staff's initial calculation of Officer salaries is reduced from $24 thousand to $12 thousand, as is shown below.[28]

FIGURE 2. W&S MODEL ADJUSTMENTS

Description	Officers	Exempt	Non Exempt	Union	Total
Actual Base Payroll (2019) calendar year	**$4,485,503**	**$196,054,195**	**$28,880,063**	**$74,566,370**	**$303,986,130**
Ave. # of Employees (FTE) (2019)	11	1,647	501	757	**2916**
Average Salary	$412,982	$119,018	$57,599	$98,547	
Allowable % Increase	1.0746	1.0746	1.0746	1.1087	
Ave. # of Employees (FTE) (Test Year)	10	1,778	457	694	**2939**
Projected Payroll	**$4,433,821**	**$227,384,217**	**$28,298,731**	**$75,778,197**	**$335,894,965**
Test Period Payroll	**$4,458,298**	**$217,403,262**	**$27,564,960**	**$74,389,787**	**$323,816,307**
Total Difference for Sharing	$24,476	$0	$0	$0	
10% Band - Allowable	$443,382	$0	$0	$0	
50% Sharing of Lesser of Difference or Band	$12,238	$0	$0	$0	
Staff Proposed Level	**$4,446,059**	**$217,403,262**	**$27,564,960**	**$74,389,787**	**$323,804,069**
Net Payroll Adjustment	**($12,238)**	**$0**	**$0**	**$0**	**($12,238)**

26 Staff/303, Cohen/2, Oregon Economic & Revenue Forecast September 2021, Volume XLI, No. 3, Table A.4, page 37.

27 PGE/300, Mersereau – Neitzke/18.

28 See Staff/304, Staff electronic workpaper, UE 394 Exhibit 304 W&S CONF.xlsx, tab 3-year W&S.

For the remaining non-Officer categories of Exempt, Non-Exempt and Union salaries, Staff makes no adjustments since the Company's filed proposal was less than Staff's calculated projection. Similarly, Staff makes no adjustments to Company's Test Year Overtime as it was less than Staff's projection.[29]

<u>Incentives</u>

Q. What does PGE propose for employee incentives?

A. For non-Officer incentives, PGE includes $18.6 million in the Test Year. PGE testifies that it removed 50 percent of its budgeted Non-Officer Incentives to be consistent with the Commission's policy regarding incentives.

Q. Does Staff agree with PGE's removal of 50 percent of non-Officer Incentives?

A. Staff agrees with the underlying principle of removing 50 percent, but believes PGE started with an unreasonably high forecast of incentives for the 2022 Test Year. Accordingly, PGE's downward adjustment of half of that forecast ($18.6 million) still leaves an unreasonably high forecast expense of the Non-Officer Incentives that are recoverable in rates.[30]

It appears the Company's base calculation of non-Officer incentives was based upon its 2021 Budget and not its 2020 actuals, as illustrated below. Its

[29] *Ibid*.

[30] Staff/302, Cohen/7, PGE's Response to Staff DR No. 162 Attach A (electronic spreadsheet), *See* Staff/304, Staff electronic workpaper, UE 394 Exhibit 304 W&S CONF.xlsx, tab Nonofficer Incent Analysis.

2022 Forecast represents what the Company has left in the revenue requirement for Non-Officer Incentives.[31]

FIGURE 3. NON-OFFICER INCENTIVES (ACTUALS, BUDGET, FORECAST)

Incentive Plan	12/1/2018 Actuals	12/1/2019 Actuals	12/1/2020 Actuals	2021 Budget	2022 Forecast
ACI	6,620,968	8,920,295	8,917,830	9,626,022	5,141,928
Notables & Misc.	817,347	698,688	132,638	291,312	145,656
PIC	12,520,508	10,756,967	8,566,799	18,554,589	9,842,233
Stock Incentive Plan	2,370,979	4,771,435	6,444,917	5,955,312	3,436,500
Grand Total	22,329,803	25,147,384	**24,062,184**	34,427,235	18,566,317

Non-Officer Incentives	Amounts
2018-2020 Average	23,846,457
50% of Actuals	11,923,229
PGE's TY Non-Officer Incentives	18,566,317
Staff Adjustment	(6,643,088)

Q. Does Staff propose an adjustment?

A. Yes. Staff averaged the actual amounts of incentives paid to employees in 2018, 2019, and 2020 to forecast the amount of incentives PGE would pay to non-Officer employees in the Test Year and halved that amount, to arrive at Test Year expense of $11.9 million. Accordingly, Staff proposes a ($6.6 million) adjustment to PGE's 2022 Test Year expense for non-Officer incentives.

Q. Does Staff have an adjustment for Officer incentives?

A. Yes. Although PGE removed its forecasted Officer incentives from the 2022 Test Year, Staff found that PGE's forecast was understated. PGE removed $5.5 million of expense for Officer incentives from the Test Year.[32] However,

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31 Staff/302, Cohen/7, PGE's Response to Staff DR No. 162 Attach A (electronic spreadsheet).
32 *See* Staff/304, Staff electronic workpaper, UE 394 Exhibit 304 W&S CONF.xlsx, tab Officer Incent Analysis.

Staff calculates the three-year average (2018-2020) of actuals as $5.9 million. Staff believes it is more appropriate to rely on an average of Officer incentives paid in 2018-2020 rather PGE's budgeted amount because these amounts are actuals and not forecasts.

Staff's adjustment of ($439 thousand) increases PGE's adjustment to total this three-year average.[33]

FIGURE 4. OFFICER INCENTIVES

Account	Acct WO	Incentive Plan	Dec-18	Dec-19	Dec-20	2021 Budget	2022 Forecast
9200006: Officer Incentive & ACI Plans	7000000861: Executive Incentive REXEC	ACI	2,635,661	2,620,715	1,070,755	2,753,772	0
9200007: A&G-Stock Incentive Plan	7000000704: DEUs Declared-Officers	Stock Incentive Plan	2,722,540	4,364,815	4,441,960	7,507,920	0
Grand Total			5,358,201	6,985,530	5,512,715	10,261,692	0

2018-2020 Average	**5,952,149**
PGE pre-filed adjustment	5,512,715
Staff adjustment	**(439,434)**

[33] UE 394 – PGE workpapers_400 Non Conf – Corp Supp Workpaper FINAL. Errata

ISSUE 2. FULL-TIME-EQUIVALENTS (FTES)

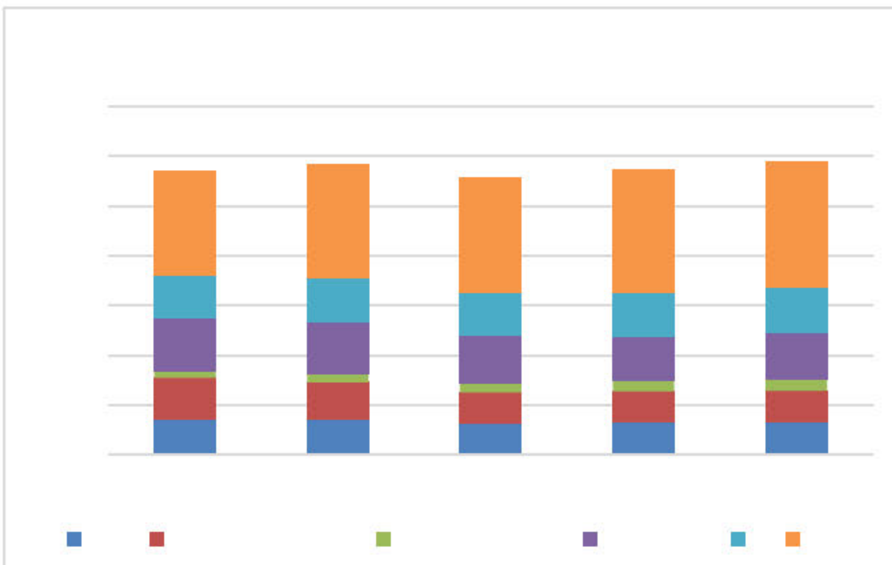
Q. Please provide the background for this issue.

A. PGE's 2022 test year forecast includes costs for approximately 164 more FTE than its most recent year of actuals (2020) and 84 more FTE than its 2018 actuals.[34] The proportion of FTE by Division is illustrated in the chart below. Noteworthy is the significant growth of Transmission and Distribution (T&D) and Customer Service.

FIGURE 5. FTE BY DIVISION

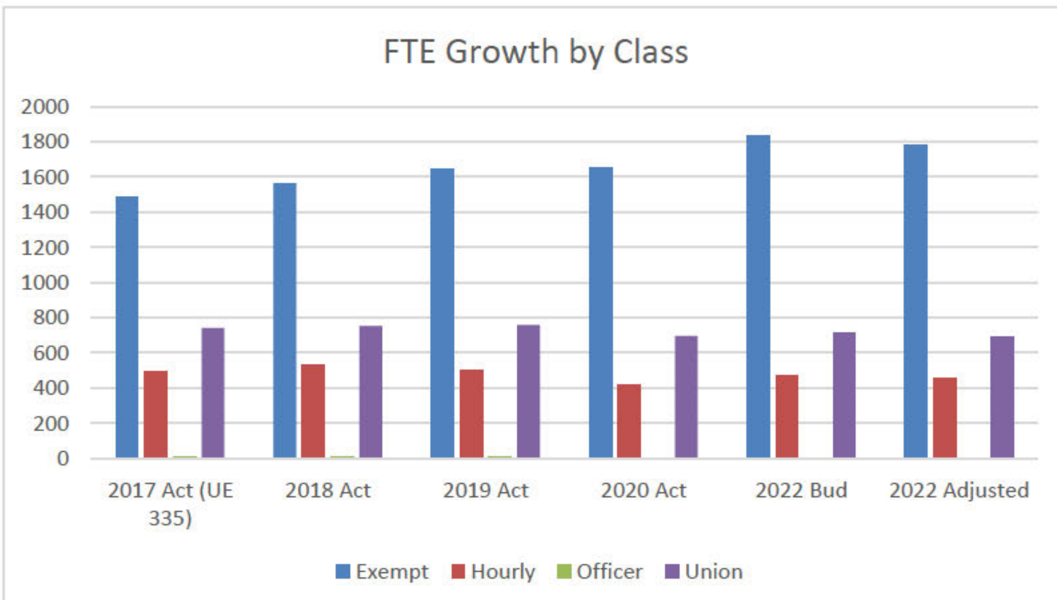
Division	Dec-18	Dec-19	Dec-20	Dec-21	Dec-22
A&G	355	361	320	329	335
Customer Accounts	420	370	307	308	309
Customer Service	64	78	86	107	116
Generation	541	528	483	443	472
IT	428	438	434	449	450
T&D	1,047	1,142	1,145	1,225	1,257
Grand Total	**2,855**	**2,916**	**2,775**	**2,861**	**2,939**

[34] Staff/302, Cohen/12, PGE's Response to Staff DR No. 391 Attach B (electronic spreadsheet).



The growth in FTEs has been concentrated in the Exempt or Straight-time/salaried category as illustrated by the chart below, which examines actuals from 2017 to 2020 alongside budgeted 2022 FTE and adjusted 2022 FTE (FTEs after PGE's O&M reduction). While the remaining categories of hourly, officer, and union are relatively stable, the exempt FTEs have proliferated since 2017.

FIGURE 6. FTE GROWTH BY CLASS



When isolating the Exempt/Salaried class, Staff finds the bulk of spending to be on A&G and T&D.[35]

[35] Staff/302, Cohen/6, PGE's Response to Staff DR No. 161 Attach A (electronic spreadsheet).

FIGURE 7. LABOR SPENDING IN EXEMPT/SALARIED BY DIVISION

Department: Division of Dept Id	CE Source	Dec - 2018	Dec - 2019	Dec - 2020	Dec - 2021	Dec - 2022
A: Customer Accounts	1101: Straight-Time Labor - Salary	7,841,604	7,073,911	6,384,316	5,606,981	5,804,298
B: Customer Service	1101: Straight-Time Labor - Salary	8,869,928	7,618,152	8,960,798	9,156,977	10,259,246
C: A&G	1101: Straight-Time Labor - Salary	58,853,461	64,416,229	64,917,441	66,445,439	69,004,943
E: T&D	1101: Straight-Time Labor - Salary	46,440,038	55,174,611	63,691,109	69,650,404	74,088,650
G: Generating - Other	1101: Straight-Time Labor - Salary	20,626,677	20,540,816	20,555,522	18,714,016	19,285,178
H: Generating - Biglow	1101: Straight-Time Labor - Salary	363,436	220,935	294,157	300,593	309,502
I: Generating - Tucannon	1101: Straight-Time Labor - Salary	204,921	211,957	253,720	325,813	335,470
O: Generating - Boardman	1101: Straight-Time Labor - Salary	1,992,468	2,068,851	1,471,076	-	-
T: Generating - Trojan	1101: Straight-Time Labor - Salary	307,981	470,569	519,390	572,941	589,922
V: Generating - Beaver	1101: Straight-Time Labor - Salary	1,019,449	808,044	704,832	626,711	645,287
W: Generating - Port Westward	1101: Straight-Time Labor - Salary	619,319	808,599	854,052	855,977	881,347
Y: Generating - Coyote	1101: Straight-Time Labor - Salary	330,836	387,172	353,095	417,493	429,867
Z: Generating - Carty	1101: Straight-Time Labor - Salary	470,236	459,627	557,537	714,658	735,839
Grand Total		147,940,354	160,259,472	169,517,044	173,388,002	182,369,549

Q. Why is Staff concerned about the FTE increase?

A. Staff has noted its concern in PGE's FTE growth since Docket No. UE 319 in which "PGE proposed growing its FTE by 270 FTE from 2016 to its 2018 test year."[36] Moreover, PGE has historically budgeted more FTEs than is necessary as can be shown from an examination of its Budgeted and Actual FTE in 2017 and 2018 where PGE overestimated its 2017 and 2018 budgets by 55 and 45 FTE, respectively.[37]

[36] UE 319 Staff/400, Gardner/*37* at 15-19 and /38 at 1-23
[37] See Staff/304, Staff electronic workpaper, UE 394 Exhibit 304 W&S CONF.xlsx, tab FTE growth.

FIGURE 8. FTE BUDGETED VS. FTE ACTUALS

Adjusted Totals by Division	UE 319	UE 335		UE 335	UE 394	
	2017 Budget	2017 Actuals	2017 Variance	2018 Budget	2018 Actuals	2018 Variance
IT	302	304	3	333	428	96
A&G	378	372	(6)	403	355	(48)
Customer Accounts	399	400	1	377	420	43
Customer Service	71	65	(7)	75	64	(11)
T&D	1,088	1,045	(43)	559	1,047	488
Generation	552	549	(3)	1,153	541	(612)
Grand Total	2,790	2,735	(55)	2,899	2,855	(45)

Q. Has the increase in payroll costs been offset by a reduction in contractor costs?

A. While PGE does project a decrease in contract labor from $42 million in 2020 actuals to $15 million in the test year (see below), past spending on contract labor does not bear this out.[38]

FIGURE 9. CONTRACT LABOR $ 2018 - TEST YEAR (2021 AND 2022 ARE BUDGETED/PROJECTIONS)

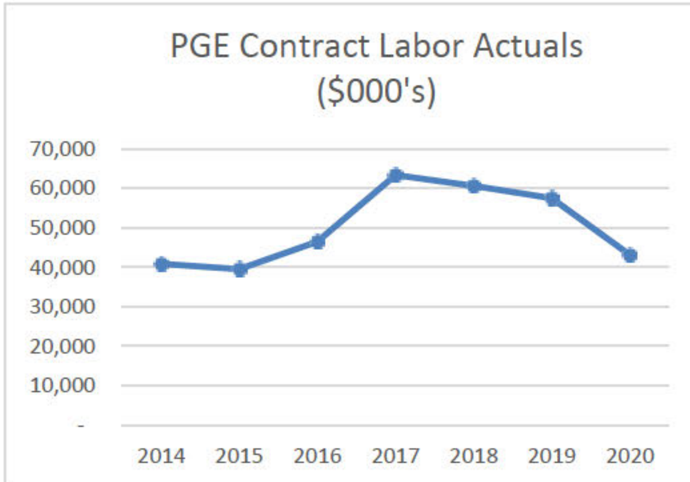
CE Source	Dec - 2018	Dec - 2019	Dec - 2020	Dec - 2021	Dec - 2022
1502: Non-PGE Labor Straight Time	57,542,202	53,430,821	35,210,574	13,177,059	12,987,892
1602: Non-PGE Labor Overtime	2,917,356	3,623,782	6,696,303	2,004,200	2,061,822
Grand Total	60,459,558	57,054,603	41,906,877	15,181,259	15,049,715

While contract labor has decreased from its high of $63 million in 2017, it has consistently been over $40 million.[39]

38 Staff/302, Cohen/6, PGE's Response to Staff DR No. 161 Attach A (electronic spreadsheet).

39 Staff/302, Cohen/4-5, UE 335 PGE's Response to Staff DR No. 101 Attach A (electronic spreadsheet), PGE's Response to Staff DR No. 101 Attach A (electronic spreadsheet).

FIGURE 10. PGE CONTRACT LABOR



Q. How does this increase in FTEs impact customers?

A. Not only do customers have to bear the brunt of excessive labor spending, but the ratio of customers per FTE has actually declined since 2017. A more pronounced drop in the number of customers per FTE is seen when viewing customers per non-Union FTE, as indicated in the charts below.[40]

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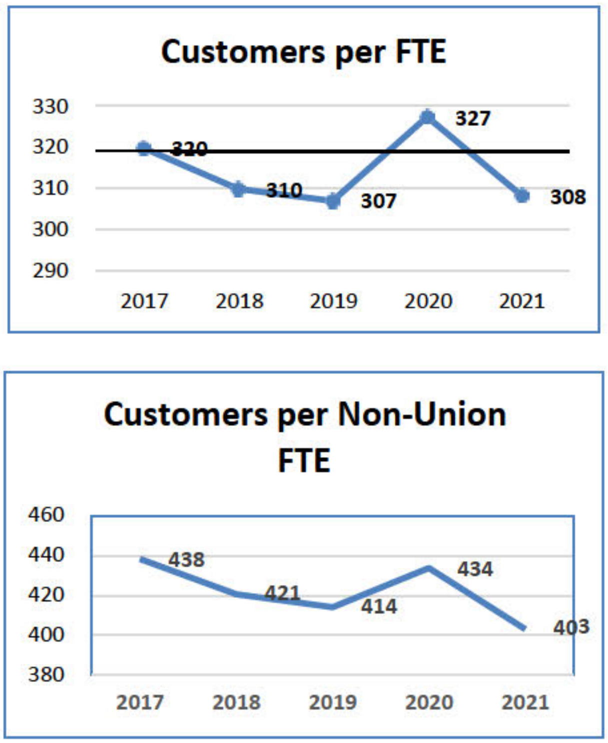
[40] *Ibid.*

FIGURE 11. CUSTOMERS PER FTE



Q. Has the Company implemented any efficiencies?

A. The Company, as previously mentioned, instituted a $10 million reduction to O&M. However, those savings are already taken into account in Staff's analysis. PGE would like to focus on total labor dollars instead of FTE in terms of defining total labor requirements, as this is more consistent with the approach their management takes when viewing resources.[41] That is, total labor dollars is more in line with PGE's "continually shifting and evolving project work" from lower wage developers to highly skilled analysts to temporary contract employees. Labor dollar metrics allows the flexibility for managers to continually change their workforce composition. PGE claims looking at FTEs in

[41] PGE/300, Mersereau – Neitzke/14.

isolation tends to mask overall changes to labor needs as contractor hours and overtime hours are excluded.[42]

Q. Does Staff propose an adjustment to the proposed 2022 test year FTE?

A. Given the trend of PGE over forecasting FTEs, Staff proposes an adjustment to PGE's proposed FTE level. Staff proposes reducing the Company's FTE count down to its most recent head count (in June), a difference of 75, mostly pronounced in the Exempt category. The adjustment is in alignment with the Commission's conclusion in UE 116 which supported Staff's reduction of PacifiCorp's manpower levels to actual levels. The resulting Order No. 01-787,[43] stated that employee levels should be based on actual levels at a specified date. Staff recommends a reduction of 75 exempt positions or $9.2 million.[44]

42 *Ibid*.
43 *Order* No. 01-787 at 41-42.
44 See Staff/304, Staff electronic workpaper, UE 394 Exhibit 304 W&S CONF.xlsx, tabs FTE adjustment, FTE.

FIGURE 12. FTE VS. HEAD COUNT, REDUCTION OF 75

	FTE DR (DR 92)					Head Count (DR 611)	
FTEs	2017	2018	2019	2020	2022 Forecast	2021 Head Count (6/21)	Head Count - FTE
Exempt	1,489	1,563	1,647	1,651	1,778	1713	(65)
Hourly	493	530	501	419	457	472	15
Officer	12	11	11	10	10	10	0
Union	741	751	757	695	694	669	(25)
Total	2,735	2,855	2,916	2,775	2,939	2864	(75)

In summary, Staff's adjustments to salary, wages, incentives and FTE are:

- Decrease salaries by $12 thousand (allocated $8 thousand O&M and $4 thousand Capital).
- Decrease incentives by $6.6 million (allocated $4.2 million O&M and $2.4 million Capital).
- Decrease FTE by $9.2 million (allocated $5.8 million O&M and $3.4 million Capital).
- Small decreases for payroll taxes ($1 thousand) and Depreciation ($169 thousand). Commensurate with the wage and salary model, Staff adjusts the test year payroll tax to reflect the decrease in taxable gross wages while also reducing depreciation expenses to reflect the reduction in capitalized compensation.[45]

[45] *See* Staff/304, Staff electronic workpaper, UE 394 Exhibit 304 W&S CONF.xlsx, tab Misc. Labor.

ISSUE 3. UNCOLLECTIBLE EXPENSE

Q. Please provide a summary of the Commission's historical treatment of uncollectible expense.

A. The amount included in a utility's Revenue Requirement for uncollectible expense is revenue sensitive because it depends on the amount of forecasted revenue. That is, the total uncollectible expense included in the Revenue Requirement is a function of the Test Year revenue and the uncollectible rate. The uncollectible rate is based on an average of the net-write offs, i.e., the uncollectible amounts that were written off the books, for the three years preceding Test Year divided by the average of the revenues for those same years. The uncollectible rate that is derived from this three-year average methodology is then multiplied by the forecast of Test Year revenue to determine the Test Year uncollectible expense for a utility's Revenue Requirement.[46] In addition, Staff reviews other materials to determine the reasonableness of the rate and level of expense produced by the three-year model.

Q. Please provide a summary of the Company's filed proposal and Staff's analysis of the issue.

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46 *See, e.g.*, *In the Matter of Avista Corporation*, Docket No. UG 246, Order No. 14-015 at 3 (January 21, 2014); and *In the Matter of Avista Corporation*, Docket No. UG 186, Order No. 09-422, Appendix A at 4 (October 26, 2009) (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on three-year average); *but see In the Matter of Idaho Power Company*, Docket No. UE 167, Order No. 05-871 (January 28, 2005) (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on four-year average); and *In the Matter of Cascade Natural Gas Corporation*, Docket No. UG 287, Order No. 15-412 (December 28, 2015) (adopting stipulation for Cascade Natural Gas general rate increase with uncollectible expense based on three-year average, removing an anomalous year).

A. According to Company testimony, "PGE has maintained the uncollectibles rate approved in PGE's last general rate (UE 335)" of .3264%."[47] While the Commission typically approves a three-year average methodology, Staff believes using such would result in a higher uncollectible rate for consumers than the Company is currently proposing. The uncollectible rate using the last three years of actuals (2018 through 2020) would result in an uncollectible rate of .346 percent.

FIGURE 13. PGE UNCOLLECTIBLES 2018-2021

Net Bad Debt Percentage - Calendar Month Calculation			
Year	*PGE L&P Revenue[1]*	*PGE Uncollectible Customer Accounts[2]*	*TOTAL PGE Bad Debt Percentage**
2018	$1,779,962,045	$5,062,542	**0.284%**
2019	$1,799,044,689	$10,381,693	**0.577%**
2020	$1,835,464,453	$3,286,771	**0.179%**
2021[3]	$1,001,758,676	$1,821,117	**0.182%**

A. Moreover, given that the Company also has a COVID deferral to manage its bad debt related to the pandemic, Staff accepts the Company's proposal to freeze its UE 335 rate.

Q. Did Staff perform any other analysis?

A. Staff inquired as to why the actuals of uncollectibles varied so much year to year. In response, the Company said that while 2017 and 2020 represent years in line with historical trends, the increase in 2018 and decrease in 2019 was driven by the "projection of increased write offs due to the replacement of PGE's customer

47 Staff/302, Cohen/13, PGE's Response to Staff DR No. 491.

information system (CIS) and subsequent pausing of collection activities during system go-live and stabilization period."[48] In Docket No. 319, PGE stated they would be suspending some collection and credit activities in order for employees to learn the new systems and for the project team to fine-tune the new system, which may "result in a higher uncollectible rate in 2018 than would otherwise occur."[49] In response, PGE increased their reserve for the uncollectible accounts balance by $6 million in order to account for this difference. However, while PGE did not incur higher write-offs in 2018, the matching principle of accounting necessitated recording the reserve (and expense) in the same period the revenues were recognized.50 In 2019, PGE did experience higher write offs due to the previously mentioned CIS implementation impacts, but the balance in the reserve was able to cover it.[51]

[48] Staff/302, Cohen/16, PGE's Response to Staff DR No. 797.
[49] UE 319/PGE/900 Stathis – Dillin/12.
[50] Staff/302, Cohen/16, PGE's Response to Staff DR No. 797.
[51] *Ibid.*

FIGURE 14: PGE UNCOLLECTIBLE ACTUALS 2012-2020

FERC 904 Uncollectibles			
Year	*Light & Power Accounts*	***Non Light & Power Accounts*	*Total PGE Uncollectibles*
2012	$6,549,944	$147,590	**$6,697,534**
2013	$5,994,750	$310,897	**$6,305,647**
2014	$6,578,110	$321,064	**$6,899,174**
2015	$4,921,201	$596,724	**$5,517,925**
2016	$4,812,097	$340,335	**$5,152,432**
2017	$5,093,172	$364,011	**$5,457,183**
2018	$13,033,285	$127,136	**$13,160,421**
2019	$1,964,942	$190,746	**$2,155,688**
2020	$7,069,010	$0	**$7,069,010**

Q. How is the Company reconciling the debt recovery under its COVID-19 deferral in UM 2114 with the debt recovery in the current rate case?

A. The total amount included in this rate case is approximately $6.5 million (using the .32635 percent uncollectible rate). Any amount above the Commission-approved uncollectible expense will be included as part of the bad debt recovery in a deferral as stipulated in Docket No. UM 2064.[52]

[52] Staff/302, Cohen/13, PGE's Response to Staff DR No. 491.

ISSUE 4. CUSTOMER ACCOUNT EXPENSES

Q. Please describe customer accounting and customer service expenses.

A. Customer accounting expense is recorded in FERC Accounts 901, 902, 903, and 905. These accounts track expenses related to Supervision, Meter Reading, Customer Records and Collection, as well as Miscellaneous Customer Accounts. Uncollectibles, Account 904, has been analyzed separately in a previous section of this testimony.

Q. Does Commission Staff have a standard for how Customer Account expenses are treated for ratemaking purposes?

A. Rule 860-026-0020 Standards Governing Promotional Activities and Concessions mandates that all promotional activities be just, reasonable, prudent, economically feasible and beneficial to both the utility and its customers. Staff reviews expenses per appropriate use per FERC account. Staff also reviews transaction-level data to ensure expenses relate to activities such as responding to customer requests, inquiries and safety concerns, resolving customer complaints, extending service to new customers, and providing information about safety and service issues.

Q. Please describe the Company's customer account expenses in the Base Year.

A. For Customer Account expenses, excluding Uncollectibles (FERC Accounts 902, 903, and 905), the Company forecasted a Test Year total of $60.4 million. There were no pre-filing adjustments performed for these accounts.

Q. How does the amount requested in the Test Year differ from historical trends?

A. While this represents a five percent overall increase from the Company's four year average of actuals (2017-2020), PGE saw a large decline in Meter Reading (FERC 902) expenses (58 percent), a smaller decline in Miscellaneous (FERC 905) expenses alongside a small increase in Customer Receipts (FERC 903) as illustrated below.

FIGURE 15. CUSTOMER ACCOUNTS HISTORICAL SPENDING

FERC Account	Description	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Budget	2022 Projected	4 Years Average (2017-2020)	Average compared to Projected
902	Meter Reading	533,423	377,022	398,441	352,224	170,551	175,334	415,278	-58%
903	Customer Receipts	46,664,695	50,172,531	55,772,614	50,657,698	55,184,635	54,450,219	50,816,884	7%
905	Misc. Customer Accounts	5,838,137	6,568,715	6,944,625	5,547,635	5,572,760	5,727,949	6,224,778	-8%
Grand Total		53,036,254	57,118,267	63,115,681	56,557,557	60,927,946	60,353,502	57,456,940	5%

Moreover, spending by labor category was also consistent from 2019 to the 2022 Test Year, with labor-intensive spending in Meter Reading, Customer Receipts and Miscellaneous expenses.[53]

FIGURE 16. CUSTOMER ACCOUNTS: LABOR VS. NON-LABOR

FERC Account	Description	Labor/Non-Labor	2019 Actuals	2020 Actuals	2021 Budget	2022 Projected
902	Meter Reading	Labor	96%	97%	100%	100%
		Non-Labor	4%	3%	0%	0%
903	Customer Receipts/Collections	Labor	54%	54%	58%	60%
		Non-Labor	46%	46%	42%	40%
905	Misc. Customer Accounts	Labor	99%	100%	100%	100%
		Non-Labor	1%	0%	0%	0%

53 Staff/302, Cohen/1, PGE's Response to Staff DR No. 58 Attach A Revised (electronic spreadsheet).

According to Company's response to Staff DR 234, the portion of meter readers to customers has been in decline since 2019.[54]

FIGURE 17. METER READERS PER CUSTOMER

		Total Number			Per 1,000 customers		
Year	Number of Customers*	Meter Readers	Customer Service Advisors	Eagles (Repairmen)**	Meter Readers	Customer Service Advisors	Eagles (Repairmen)**
2018	881,766	6	184	36	0.0068	0.2087	0.0408
2019	890,019	5	158	37	0.0056	0.1775	0.0416
2020	902,237	3	166	34	0.0033	0.1840	0.0377
2021	909,748	3	170	35	0.0033	0.1869	0.0385

Q. How did Staff perform its analysis of the Company's customer accounting and customer expense?

A. After reviewing historical trends, Staff reviewed Company's transactional data in its response to SDR 57 and submitted DR 253 requesting copies of referenced materials.[55]

Q. Did Staff find any issue with customer accounting in the Company's application?

A. No.

54 Staff/302, Cohen/8, PGE's Response to Staff DR No. 234.
55 Staff/302, Cohen/11, PGE's Response to Staff DR No. 253 Attachment A (electronic spreadsheet).

ISSUE 5. ADVERTISING EXPENSES

Q. Does the Commission have a standard means of determining how advertising expenses are treated?

A. Yes, OAR 860-026-0022 specifies how advertising expenses are treated in a rate case. There are five categories (A-E) and each has a different standard for inclusion in rates. Category "A" includes energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses.[56] Advertising expenses in this category are presumed reasonable when expenses are twelve and one-half hundredths of one percent (0.125 percent) or less of the gross retail operating revenues determined in that proceeding.

Category "B" includes legally-mandated advertising expenses, and they are assumed to be reasonable for rate-making purposes.[57] Category "C" includes institutional advertising expenses, promotional advertising expenses, and any other advertising expenses not fitting into Category "A," "B," or "D".[58] Utilities must demonstrate these expenses are just and reasonable for inclusion in rates, as well as separately state the amount of advertising expenses in this category. Category "D" includes political advertising expenses and nonutility advertising expenses, which are presumed to be not

56 OAR 860-026-0022(2)(a).
57 OAR 860-026-0022(2)(b).
58 OAR 860-026-0022(2)(c).

just and reasonable for ratemaking purposes.[59] Finally, Category "E" includes energy efficiency or conservation advertising expenses that relate to a Commission-approved program. Utilities must show these expenses are reasonable and recoverable in rates. With Commission approval, advertising expenses in Category "E" may be capitalized.[60]

Q. Please describe the Company's request for advertising.

A. The Company proposes to include approximately $2 million in Category A and five thousand in its mandated Category B advertising in the 2022 Test Year as illustrated below.[61]

FIGURE 18. CATEGORY A ADVERTISING IN THE TEST YEAR

Category	FERC Account	Test Year $
A	909	$ 2,029,309
B	909	$ 5,257
TOTAL		$2,034,566

PGE has excluded $1.2 million in Category C Institutional/Promotional Advertising (FERC 930.1) as well as $13 thousand in political advertising or Category D.[62] PGE does not have any Category E Advertising expenses in its Test Year.

Q. Please describe your analysis of the Company's proposed advertising expenses.

[59] OAR 860-026-0022(2)(d).
[60] OAR 860-026-0022(2)(e).
[61] Staff/302, Cohen/18, PGE's Confidential Response to Staff DR No. 104 Attach A (electronic spreadsheet).
[62] *Ibid*.

A. First, Staff analyzed the Company's transactional data shown in the Company's response to Standard Data Request No. 57 and inquired further about its largest advertising expenditures in the base year of 2020 (vendors Lee David Litchy and Elizabeth Bye).[63] Staff confirmed the advertisements were entirely related to consumer safety, energy efficiency, and billing assistance.

FIGURE 19. CATEGORY A VENDORS BY SPENDING IN BASE YEAR

Name	CATEGORY	Total
⊟ LEE DAVID LITCHY	A	1,037,250
⊟ ELIZABETH BYE	A	315,143
⊟ PARTNERS ON DEMAND INC	A	129,955
⊟ CULVER COMPANY LLC	A	32,000
⊟ OREGON CHILDREN'S THEATRE	A	26,000
⊟ DARK HORSE COMICS LLC	A	17,000
Grand Total		**1,676,712**

Staff also reviewed PGE's base year expenditures, reviewing the Category A descriptions below. The largest category (Advertising Communications) focused on customer bill help, clean energy via Wheatridge, and winter safety. Collateral Communications was composed of expenses for customer newsletters, printing, and mailing services. Safety Education involved the provision of safety related promotional materials and presentations. Powerchoice addressed printing for the Powerchoice bill stuffers in accordance with the SB 1149 Public Purchase Charge Schools Program requirements. In addition, smaller amounts of overhead expense

[63] Staff/302, Cohen/9, PGE's Response to Staff DR No. 236.

for special events such as COVID-19 and Public Safety Power Shutoffs (PSPS) were included.

FIGURE 20. CATEGORY A BASE YEAR SPENDING BY DESCRIPTION

CATEGORY	AWO Description	Total
A	Advertising Communications	944,832
	Collateral Communications	592,413
	Safety Education	112,650
	POWERCHOICE	18,495
	02.29.2020 COVID-19	3,704
	09.06.2020 PSPS and High Winds	2,611
	External Digital Communications	1,105
	Strategy-Elevate the Brand	-
	Subscription to Getty images for photo needs	858
	Salesforce - Plan/Train (Expense)	44
Grand Total		**1,676,712**

Q. How do the Company's advertising expenses compare to historical trends when categorized under the OAR 860-026-0022 categories mentioned above?

A. When examining Category A from 2017 to 2020, the largest increases have been to "Other Outside Services" as illustrated below.[64]

64 Staff/302, Cohen/15, PGE's Response to Staff DR No. 583.

FIGURE 21. CATEGORY A HISTORICAL SPENDING

Category	CE plus Description	Sum of 2017	Sum of 2018	Sum of 2019	Sum of 2020
Cat A - Informational	1101 - Straight-Time Labor - Salary	70,241	114,458	232,040	223,218
	1502 - Non-PGE Labor Straight Time	274,860	230,427	37,767	6,562
	1602 - Non-PGE Labor Overtime	-	221	-	-
	2110 - Other Materials & Equipment	2,234		2,526	12,000
	2111 - Office Supplies	2,918			600
	2205 - Advertising Services	616,000	576,226	526,150	386,250
	2207 - Marketing Services			28,000	5,600
	2209 - Outside Printing Services	248,859	211,312	140,560	110,321
	2217 - Recruitment and Hiring Service	232			
	2250 - Other Outside Services	396,877	333,261	504,656	992,890
	2404 - Business Meals & Entertainment		212		
	2450 - Other Employee Business Exp	380	695	927	15,155
	2501 - PGE Printing Services	39,238	22,551	22,251	11,845
	5101 - Pension Service Cost	5,576	9,264	15,015	14,755
	5102 - Employee Support Offset	543	1,284	2,582	2,667
	5103 - Incentives Overhead	3,911	5,873	10,230	9,772
	5104 - Vacation Overhead	13,495	20,007	41,506	38,277
	5105 - Employee Benefits Overhead	22,464	36,737	76,666	66,680
	5106 - Payroll Taxes	7,565	11,786	24,066	20,860
	5112 - OtherPostEmplBene-SvcCostLoad		1,108	1,817	1,654
	5117 - OtherPostEmplBenNonSvcCstLoad		705	1,110	607
Cat A - Informational Total		**1,705,394**	**1,576,129**	**1,667,869**	**1,919,712**

Staff's review of the expenses reveal they are the same as those already reviewed, which focused on customer bill help, clean energy and winter safety.[65]

FIGURE 22. CATEGORY A OTHER OUTSIDE SERVICES

Vendor	CATEGORY	CE plus Description	Total
LEE DAVID LITCHY	A	2250 - Other Outside Services	570,000
ELIZABETH BYE	A	2250 - Other Outside Services	315,143
CULVER COMPANY LLC	A	2250 - Other Outside Services	32,000
OREGON CHILDREN'S THEATRE	A	2250 - Other Outside Services	26,000
DARK HORSE COMICS LLC	A	2250 - Other Outside Services	17,000
SYNARCHY SCIENCE LLC	A	2250 - Other Outside Services	11,030
GETTY IMAGES US INC	A	2250 - Other Outside Services	10,900
	A	2250 - Other Outside Services	6,607
PARTNERS ON DEMAND INC	A	2250 - Other Outside Services	2,239
THE BARTECH GROUP INC	A	2250 - Other Outside Services	958
Rigby,Anna-Katharina	A	2250 - Other Outside Services	750
NORTHWEST INTERPRETERS INC	A	2250 - Other Outside Services	163
Armstrong,Taaj R	A	2250 - Other Outside Services	100
Grand Total			**992,890**

65 Staff/302, Cohen/9, PGE's Response to Staff DR No. 236.

Q. What is your recommendation regarding advertising expense?

A. The Company has not exceeded the 0.125 percent limit of Category A Advertising and all expenses appear to be prudent. Therefore, Staff has no adjustment.

ISSUE 6. HR/EMPLOYEE SUPPORT REDUCTIONS

Q. Please describe the reductions to expense for HR/Employee Support budgets.

A. In its testimony PGE detailed a $0.5 million reduction to its budget for HR/Employee support, as well as a $1.8 million reduction to the Office of Corporate Finance Officer (CFO) and Treasurer department.66 PGE states the reductions are "stretch goals" and that "[w]hile PGE is committed to these savings, it has not yet been determined exactly how these savings will be realized."[67]

Q. How did Staff perform its analysis of these reductions?

A. After reviewing the Company's response to Staff DR 254, Staff reviewed PGE's adjustment, illustrated below, for these savings.

FIGURE 23. HR/EMPLOYEE SUPPORT REDUCTIONS BY COST ELEMENT AND ACCOUNT

Corporate Support Line	Dept Id	Cost Element: Labor/Non-Labor of CE Source	Account	Acct WO	Dec - 2021	Dec - 2022	Base Year-Test Year Delta
Corporate Governance RCs	541: Office of CFO and Treasurer	Non-Labor: Non-Labor	9210002: A&G-NonLabor Exp-Nonalloc	3000000959: Budget Placeholder	(1,750,000)	(1,800,314)	(1,800,314)
HR/Employee Support (net of capital allocs.) RCs	809: VP HR Diversity, Equity & Incl	Non-Labor: Non-Labor	9230001: Outside Services Employed	3000000959: Budget Placeholder	(500,000)	(514,376)	(514,376)
Grand Total					(2,250,000)	(2,314,690)	(2,314,690)

Q. Does Staff have any objection to including this reduction?

A. No.

Q. Does this conclude your testimony?

A. Yes.

---

66 PGE/400, Ajello-Batzle/ 6.
67 *Ibid.*

CASE: UE 394
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATION STATEMENT

NAME: Heather Cohen

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE., Suite 100
Salem, OR. 97301

EDUCATION: Bachelor of Arts, Political Science
Fordham University, New York, NY

Master of Public Policy
American University, Washington, DC.

EXPERIENCE: I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since January 2020 in the Energy, Rates and Finance Division. I currently perform a range of financial analysis duties related to natural gas, electric and water utilities, with a focus on operations and maintenance. I have worked on the following general rate and power cost dockets: UG 388, UG 389, UG 390, UE 374, UE 390, UE 391 and UW 184.

I have ten years of professional level budget and fiscal analysis experience. I was previously employed as a Budget Analyst with the Oregon Department of Education (ODE), where I was the lead analyst for the Early Learning Division (ELD) which includes the federal $97M Child Care Development Fund (CCDF) and $37M Preschool Promise program. Prior to ODE, I was a Senior Financial Analyst for the state of Texas's Department of Family and Protective Services and Health and Human Services. Before that, I was a Project Manager for the University of Southern California where I directed data collection and analysis, staffing and deliverables for a $1.2M federal grant related to the provision of mental health services in Los Angeles County. Prior to USC, I was a Senior Budget Analyst for the City of New York responsible for the $1B expense budget of the Administration for Children's Services (ACS).

CASE: UE 394
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

October 25, 2021

PGE's Response to Staff Data Request 58 Attach A Revised

Is

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PGE's Response to Staff Data Request 92 Attach A Revised

Is

Filed in electronic format

July 19, 2021

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Standard Data Request 093
Dated March 10, 2015

Request:

For the Test Year, please provide the breakout between O&M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon expressed as a percentage.

Response:

The breakout between O&M and rate base for all 2022 labor[1] cost is as follows:

36.7% - Capital,
63.3% - O&M.

All labor relates to Oregon retail prices.

[1] The methodology used to split labor between O&M and capital for this data request is consistent with the methodology used for FERC Form 1 pages 354-355 reporting, which does not include contract labor.

PGE’s Response to Staff Data Request 101 Attach A

(UE 335)

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PGE’s Response to Staff Data Request 101 Attach A

Is

Filed in electronic format

PGE's Response to Staff Data Request 161 Attach A

Is

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PGE's Response to Staff Data Request 162 Attach A

Is

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August 13, 2021

To: Heather Cohen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 234
Dated July 30, 2021

Request:

In an Excel spreadsheet, please provide the ratio, per 1,000 customers, of service technicians and meter readers in Oregon for the past three years. Please **supplement** with 2021, when available **until a final order is issued in this case**.

Response:

Attachment 234-A provides requested details. Based on a discussion with Staff on 08/03/2021 PGE also provided the ratio of customer service advisors per 1,000 customers.

August 13, 2021

To: Heather Cohen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 236
Dated July 30, 2021

Request:

For purposes of this request, the term "copy" means:

a. *For printed advertising, a hard copy or pdf of the material;*
b. *For a radio broadcast, a hard copy or pdf of the radio script;*
c. *For a television broadcast, a link to a video of the advertisement on a webpage accessible by Staff, a DVD, or in a file format viewable on a modern Windows operating system;*
d. *For an online advertisement, an Adobe PDF of any webpages created; and*
e. *For other items not listed above, including but not limited to billboards, banners, displays, hats, mugs, and pens, – a hard copy picture or digital picture that provides an accurate depiction of the item.*

In reference to Company's response to DR 57 A, please provide a copy of the advertising media produced for each of the line items below:

Account	Account Description	Month Number	Line Description	Ref No	Vendor	PGE Share
9090001	CustSvc-InformAdvertisingExp	202012	Clean Wheatridge Digital and R	10948810	LEE DAVID LITCHY	165000
9090001	CustSvc-InformAdvertisingExp	202012	Customer Value Bill Help Digit	10948810	LEE DAVID LITCHY	146000
9090001	CustSvc-InformAdvertisingExp	202012	Clean Business Radio and Digit	10948810	LEE DAVID LITCHY	105000
9090001	CustSvc-InformAdvertisingExp	202012	Winter Safety Digital and Radi	10947208	LEE DAVID LITCHY	50000
9090001	CustSvc-InformAdvertisingExp	202009	Other service requested	10932901	LEE DAVID LITCHY	50000
9090001	CustSvc-InformAdvertisingExp	202001	CO1 to POC0050-18130: Demand R	10866137	LEE DAVID LITCHY	50000
9090001	CustSvc-InformAdvertisingExp	202008	CO01 to POC00500000018607 Bill	10917917	LEE DAVID LITCHY	40000
9090001	CustSvc-InformAdvertisingExp	202010	You Have The Power Radio Ads E	10937547	LEE DAVID LITCHY	20000
9090001	CustSvc-InformAdvertisingExp	202012	General Customer Communication	10953566	ELIZABETH BYE	26262.5
9090001	CustSvc-InformAdvertisingExp	202012	Disconnection Customer Communi	10953566	ELIZABETH BYE	17632.5
9090001	CustSvc-InformAdvertisingExp	202012	Graphic design	10953566	ELIZABETH BYE	16800
9090001	CustSvc-InformAdvertisingExp	202003	General Customer Communication	10881048	ELIZABETH BYE	15700
9090001	CustSvc-InformAdvertisingExp	202011	Graphic design	10946804	ELIZABETH BYE	14825
9090001	CustSvc-InformAdvertisingExp	202012	Graphic design	10952115	ELIZABETH BYE	14500
9090001	CustSvc-InformAdvertisingExp	202008	General Customer Communication	10923476	ELIZABETH BYE	12325
9090001	CustSvc-InformAdvertisingExp	202003	Customer Newsletters	10881048	ELIZABETH BYE	12262.5
9090001	CustSvc-InformAdvertisingExp	202012	Clean Wheatridge Digital and R	10948810	LEE DAVID LITCHY	165000
9090001	CustSvc-InformAdvertisingExp	202012	Customer Value Bill Help Digit	10948810	LEE DAVID LITCHY	146000
9090001	CustSvc-InformAdvertisingExp	202012	Clean Business Radio and Digit	10948810	LEE DAVID LITCHY	105000
9090001	CustSvc-InformAdvertisingExp	202012	Winter Safety Digital and Radi	10947208	LEE DAVID LITCHY	50000
9090001	CustSvc-InformAdvertisingExp	202009	Other service requested	10932901	LEE DAVID LITCHY	50000
9090001	CustSvc-InformAdvertisingExp	202001	CO1 to POC0050-18130: Demand R	10866137	LEE DAVID LITCHY	50000
9090001	CustSvc-InformAdvertisingExp	202008	CO01 to POC00500000018607 Bill	10917917	LEE DAVID LITCHY	40000

Response:

Attachment 236-A provides requested information.

PGE's Response to Staff Data Request 253 Attach A

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PGE's Response to Staff Data Request 391 Attach B

Is

Filed in electronic format

September 2, 2021

To: Heather Cohen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 491
Dated August 19, 2021

Request:

Per Order No. 20-401, Docket No. UM 2114, signatory parties to a stipulated agreement were authorized to defer costs associated with the COVID-19 emergency for later ratemaking[1], including, "For bad debt expense, the amount that is currently being collected from customers for bad debt, as determined in its last general rate proceeding, would be the baseline. Any amount of bad debt expense incurred above this baseline, including arrearage amounts waived and associated program costs, in 2020, 2021, and 2022 would be deferred for later recovery. PGE is authorized to defer said costs under Docket No. UM 2064.

a. Please demonstrate how the Company is distinguishing bad debt recovery under UM 2064 and establishing bad debt recovery under UE 394 in rates.
b. Please provide a net estimated rate impact to customers associated with bad debt recovery as proposed under UE 394 and UM 2064 if the latter is i) Spread across all consumer classes or ii) Spread across the residential class only.
c. Please provide a breakout for the uncollectibles amount the Company is seeking to recover in this rate case as well as the most up to date amount of bad debt related to COVID-19 the Company has deferred.

Response:

a. PGE proposes to continue using the 0.32635% uncollectible rate approved in PGE's most recent general rate case (Docket No. UE 335). The total amount included in the UE 394 test year forecast for uncollectible expense is approximately $6.5 million. Any amount above the Commission-approved uncollectible expense will be included as part of the bad debt recovery in a deferral as stipulated in Docket No. UM 2064. Bad debt expense deferred as of end of June 2021 is $16,375,946.
b. Please refer to Attachment 491-A, which provides the net estimated base rate impacts under these two scenarios; i) all cost of service customers and ii) only residential customers.
c. Please refer to the response in part a.

[1] Order No. 20-401, UM 2114 Attachment A at p. 11-12.

September 2, 2021

To: Heather Cohen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 493
Dated August 19, 2021

Request:

Please provide the amount of Officer Incentives capitalized in Plant Costs from 2016 to 2020 (calendar years).

Officers' Incentives Capitalized in Plant			
Calendar Year	PGE	Allocated to Oregon Jurisdiction	Allocated to Oregon Jurisdiction and included in rate base
2016	$	$	$
2017			
2018			
2019			
2020			
Total			

Response:

PGE does not capitalize Officer Incentives and did not do so from 2016 to 2020.

PGE's Response to Staff Data Request 583 Attach A

Is

Filed in electronic format

October 1, 2021

To: Heather Cohen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 797
Dated September 17, 2021

Request:

In Company's response to DR 58 Attach A Revised (see below illustration) as well as Company's response to DR 185 Attach A (tab e) there were very large variances in Account 904. A) Please explain the activities/costs that get entered into this account. B) Please describe why the large variances occurred between each of the following years 2017-2018, 2018-2019 and 2019-2020.

Util/Non-Util	Utility					
	Values					
FERC Accoun	Sum of 2017 Actuals	Sum of 2018 Actuals	Sum of 2019 Actuals	Sum of 2020 Actuals	Sum of 2021 Budget	Sum of 2022 Filed RevReq
904	5,457,183	13,160,421	2,155,688	7,069,010	5,977,000	6,962,301
Grand Total	**5,457,183**	**13,160,421**	**2,155,688**	**7,069,010**	**5,977,000**	**6,962,301**
	% Change	141%	-84%	228%	-15%	16%

Response:

FERC Account 904 – uncollectible expense relates to retail and tariffed billings that, after a lengthy collection process, remain unpaid.

2017 – Represents a year that is in line with historical trends.
2018 – The increase in the reserve for uncollectible accounts balance in 2018 was driven by the projection of increased write offs due to the replacement of PGE's customer information system (CIS) in May 2018 and subsequent pausing of collection activities for system go-live and the stabilization period. As noted in PGE Exhibit 900 (Docket UE 319) limiting credit and collection activities is a standard practice when implementing a new CIS. PGE increased the reserve in 2018 to an approximately $11M balance, primarily via a $6M increase for CCB implementation impacts. While PGE did not experience higher write offs in 2018, the matching principle of accounting necessitated recording the reserve (and expense) in the same period the revenues were recognized.
2019 – PGE experienced higher write offs due to the CCB implementation impacts noted in 2018 but did not incur additional expense as the balance in the reserve for uncollectible accounts was adequate to cover the higher write-offs.
2020 – Represents a year in line with historical trends.

STAFF EXHIBIT 302 PAGE 18

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PROTECTIVE ORDER NO. 21-206

**PGE's Confidential Response to Staff Data Request 104
Attach A CONF**

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CASE: UE 394
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

October 25, 2021

Oregon Economic and Revenue Forecast

Kate Brown
GOVERNOR

September 2021

Volume XLI, No. 3

Release Date: August 25th, 2021

Oregon Office of Economic Analysis

Sep 2021 - Other Economic Indicators

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GDP (Bil of 2012 $),												
Chain Weight (in billions of $)	19,091.7	18,426.1	19,640.7	20,615.9	21,041.4	21,455.2	21,912.7	22,420.9	22,956.9	23,482.8	23,983.0	24,499.4
% Ch	2.2	(3.5)	6.6	5.0	2.1	2.0	2.1	2.3	2.4	2.3	2.1	2.2
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2012=100	112.3	113.6	117.5	120.2	122.7	125.5	128.4	131.4	134.5	137.6	140.9	144.3
% Ch	1.8	1.2	3.4	2.3	2.1	2.3	2.3	2.3	2.3	2.4	2.4	2.4
Personal Consumption Deflator,												
Chain Weight U.S., 2012=100	109.9	111.1	114.6	117.0	119.2	121.5	124.0	126.5	129.2	132.0	135.1	138.1
% Ch	1.5	1.2	3.1	2.1	1.8	2.0	2.0	2.0	2.1	2.2	2.3	2.3
CPI, Urban Consumers,												
1982-84=100												
West Region	270.3	275.1	286.0	295.0	301.8	308.7	315.8	323.3	331.2	339.6	348.5	357.7
% Ch	2.7	1.7	4.0	3.2	2.3	2.3	2.3	2.4	2.4	2.5	2.6	2.6
U.S.	255.7	258.8	268.3	274.8	280.5	286.3	292.4	298.7	305.4	312.6	320.2	328.1
% Ch	1.8	1.2	3.7	2.4	2.1	2.1	2.1	2.1	2.2	2.4	2.4	2.4
Oregon Average Wage												
Rate (Thous $)	57.2	62.0	65.0	66.6	69.3	72.0	74.8	77.7	80.8	84.0	87.4	91.0
% Ch	3.6	8.4	4.8	2.4	4.0	3.9	3.9	3.9	3.9	4.0	4.1	4.1
U.S. Average Wage												
Wage Rate (Thous $)	61.7	65.9	70.0	71.8	74.1	76.9	79.9	83.2	86.7	90.3	94.1	98.1
% Ch	3.3	6.8	6.2	2.6	3.2	3.7	4.0	4.1	4.2	4.2	4.2	4.3
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	439.0	474.7	533.7	554.5	572.8	593.1	614.3	636.2	659.3	684.1	709.1	735.1
% Ch	4.9	8.1	12.4	3.9	3.3	3.5	3.6	3.6	3.6	3.7	3.7	3.7
FHFA National Housing Price Index												
1991 Q1=100	271.3	292.4	327.7	350.6	366.0	380.8	395.3	409.4	423.1	436.5	450.0	463.6
% Ch	5.2	7.8	12.1	7.0	4.4	4.0	3.8	3.6	3.3	3.2	3.1	3.0
Housing Starts												
Oregon (Thous)	20.7	18.1	20.6	20.3	21.8	22.4	22.4	22.3	22.6	22.7	22.8	22.7
% Ch	5.7	(12.4)	13.5	(1.3)	7.3	3.0	(0.2)	(0.5)	1.7	0.2	0.4	(0.3)
U.S. (Millions)	1.3	1.4	1.6	1.4	1.3	1.3	1.3	1.3	1.3	1.2	1.2	1.2
% Ch	3.6	8.1	12.6	(8.7)	(6.2)	(1.4)	(0.8)	(2.5)	(2.2)	(0.7)	(0.4)	(1.4)
Other Indicators												
Unemployment Rate (%)												
Oregon	3.7	7.6	5.8	5.1	4.0	3.9	4.0	4.1	4.1	4.1	4.1	4.1
Point Change	(0.3)	3.9	(1.8)	(0.7)	(1.1)	(0.1)	0.1	0.1	0.0	0.0	0.0	0.0
U.S.	3.7	8.1	5.6	4.2	3.6	3.6	3.8	3.9	3.9	3.9	4.0	4.0
Point Change	(0.2)	4.4	(2.5)	(1.5)	(0.6)	0.0	0.2	0.1	(0.0)	(0.0)	0.1	0.1
Industrial Production Index												
U.S, 2012 = 100	102.3	95.0	101.1	105.9	107.5	108.8	110.4	112.1	113.8	115.5	117.3	119.2
% Ch	(0.8)	(7.2)	6.4	4.8	1.5	1.2	1.5	1.6	1.5	1.5	1.5	1.6
Prime Rate (Percent)	5.3	3.5	3.2	3.3	3.3	3.7	4.2	4.7	5.2	5.6	5.8	5.8
% Ch	7.7	(32.9)	(8.3)	0.0	2.1	10.0	13.7	12.1	10.8	9.4	1.9	0.0
Population (Millions)												
Oregon	4.21	4.24	4.26	4.29	4.32	4.35	4.39	4.43	4.46	4.50	4.53	4.57
% Ch	0.9	0.7	0.4	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
U.S.	330.4	331.5	332.0	333.1	334.7	336.4	338.1	340.0	341.8	343.6	345.5	347.3
% Ch	0.5	0.3	0.1	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Timber Harvest (Mil Bd Ft)												
Oregon	3,541.3	3,377.5	3,664.9	3,628.4	3,621.2	3,672.9	3,703.5	3,732.2	3,759.2	3,760.1	3,761.0	3,762.0
% Ch	(12.9)	(4.6)	8.5	(1.0)	(0.2)	1.4	0.8	0.8	0.7	0.0	0.0	0.0

CASE: UE 394
WITNESS: HEATHER COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 304

Exhibits in Support
Of Opening Testimony

October 25, 2021

Staff Exhibit 304 Wage and Salary Model

Is

Filed in electronic format

CASE: UE 394
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

REDACTED

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Michelle Scala. I am a Senior Utility Analyst employed in the Strategy Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Staff Exhibit 401.

Q. What is the purpose of your testimony?

A. My opening testimony discusses Staff's analysis and position on the following issues:

- Test Year expense for Customer Services (Operations and Maintenance/Non-Labor)
- PGE's proposed changes to its decoupling mechanism;
- PGE's proposed changes to its tariffs for Street and Highway Lighting
- Recovery of costs related to PGE's Fee Free Bank Card Payment Option
- House Bill 2475 Implementation

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. CUSTOMER SERVICE (O&M/NL) EXPENSE

Q. What are Customer Service expenses and what amount does PGE include in the 2022 Test Year for Customer Service O&M/NL.

A. Customer services expense is recorded in FERC Account 908, which is for "the cost of labor, materials used and expenses incurred in providing instructions or assistance to customers, the object of which is to encourage safe, efficient and economical use of the utility's service." The Company has proposed to increase total customer service O&M costs for the 2022 Test Year relative to the Company's 2020 actual costs by approximately $12.9 million. Of this amount, $2,988,769 is associated with Customer Service O&M/NL, including a $100,476 increase associated with the Company's IT allocation. The Company indicated that increased expenses associated with the Transportation Electrification (TE) program and expansion of bank card payment options are the primary drivers of increased O&M/NL costs in the Test Year.[1]

Q. Please describe the Company's Customer Service O&M/NL expenses in the Base Year.

A. For the 2020 Base Year, actual costs totaled $4,778,953.05 (excluding the $1,270,780 Base Year IT allocation associated with this account).[2] Approximately 16 percent of these costs are attributed to the Brand/Marketing/Communications; Customer Insights; VP Customer Solutions; Product Marketing; and Grid Products & Integration Department IDs.

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1 PGE/500. Bekkedahl-McFarland/7.

2 Staff/402, Scala/1, UE 394 PGE Workpapers_500 Non Conf/Cust Acct-Svcs Work paper_06.18.21.

Q. How does the amount requested in the Test Year differ from historical trends?

A. The Company's Test Year Customer Service O&M/NL expenses total $7,904,195 (excluding the $1,371,256 Test Year IT allocation associated with this account). This translates to a $2,988,769 delta between Base Year and Test Year totals for FERC account 908 NL. Costs attributed to the Brand/Marketing/Communications Department ID have increased significantly and are more than double the $729,924 three-year average between 2018 and 2020.

Other Company Departments showing significant incremental and new associated costs include: Residential Marketing Purchase Order,[3] and Transportation Electrification. In a review of historical budgets versus actuals, Staff found that the Company consistently over-projected O&M/NL expenses.[4] For example, Brand/Marketing/Communications was budgeted an average of $2.4 million in annual expenses between 2018 and 2020; compared to significantly lower actual costs, as stated above.

Q. Please describe Staff's evaluation of primary cost drivers behind the O&M/NL increase.

A. Staff reviewed the Company's Customer Services work papers and SDRs 57 and 58 to identify and verify allocation of costs as described in PGE's opening testimony. As will be described below, the $1.8 million in non-labor TE

3 According to the Company, this Department has been renamed to "Flexible Load Prod Portfolio".

4 Staff/402, Scala/2, PGE Response to OPUC DR 864, Attachment A.

program costs were allocated to FERC account 908 under the newly created department ID, 542: Transportation Electrification.[5] Staff is proposing these costs be reallocated to the appropriate FERC accounts subject to adjustments described in Staff Exhibit 1700. Staff was unable to find costs associated with the expansion of the fee free bank card program in Customer Services O&M/NL accounts and located these costs in Customer Accounts under FERC account 903, “Customer Records and Collection Expenses”, which was later confirmed by the Company.

To this end, expansion of the fee free bank card payment option is not a primary cost driver specifically for Customer Services O&M/NL. In a separate DR, Staff investigated an increase of $1.2 million associated with the Department ID 538: Residential Marketing P.O. which revealed a misclassified labor expense associated with Demand Response growth in the Flexible Load Portfolio (FLP).[6] These amounts may be subject to a correction that could shift the associated incremental expense out of Customer Services O&M/NL accounts. In communications with Staff looking to resolve this issue, the Company indicated that the FERC 908 FLP costs are reflected as outside services, but that the Company believes the program will be better served with PGE FTE despite none being requested in association with these funds at this time.

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5 See PGE/500 Bekkedahl-McFarland/16.
6 Staff/402, Scala/3, PGE Response to OPUC DR 861.

Q. Please elaborate on the increased costs associated with the TE program.

A. In the Company's opening testimony, PGE indicated that the 2022 forecast for TE is $1.8 million in incremental, NL expenses. Cited costs include planning and design, charging data management and analytics, market studies, program evaluation and equipment O&M.[7] In the Company's associated non-confidential work papers, the total of $1.8 million is shown in FERC account 908, "Customer Assistance Expenses" under Cost Element 2200, "Outside Services". In a response to Staff DR's 747 and 862, PGE provided additional value estimates and expense data for TE costs including non-labor categories: Program Operations, Outside Services, and Other Expenses. Please refer to Staff Exhibits 1700 and 1704 for further analysis of these costs.

Q. Please describe the increased costs associated with bank card payment options.

A. The Company attributes incremental costs in the 2022 Test year to the expansion of electronic payment options available to customers, expanding the fee free bank card payment option to nonresidential customers, and increased FFBC adoption rates among residential and nonresidential customers.[8] For additional detail on costs associated with FFBC expansion and adoption rates, please see Staff Exhibit 400, Issue 4, Fee Free Bank Card Payment beginning on page 27.

[7] PGE/500, Bekkedahl-McFarland/16.
[8] PGE/500, Bekkedahl-McFarland/17.

Q. Please describe the Company's 2022 Test Year forecast for bank card payment adoption.

A. The Company forecasted the number of residential bank card transactions to increase at a rate of 0.2 percent each month in 2022.[9] For the number of nonresidential bank card transactions, the Company forecasts a month over month increase of 5 percent.[10]

Q. How does the forecast compare to historical adoption rates of the bank card payment option?

A. The residential forecast for transactions is lower than historical trends for month-to-month adoption (2.37 percent) but reflects a higher initial penetration rate commensurate with actual transaction volumes provided to Staff.[11] The nonresidential forecast for test year transactions is higher than historical adoption rates (2.12 percent) but lower than average month to month growth since the Company began offering the fee free option to nonresidential customers (9.5 percent). For additional detail, please see Staff Exhibit 400, Issue 4, Fee Free Bank Card Payment on pages 27-31.

Q. How does Staff propose to adjust forecasted adoption rates?

A. Staff does not propose any changes with regard to the residential forecast for FFBC adoption. Staff does propose to reduce the forecasted rate of monthly

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9 Staff/402, Scala/4, PGE Response to OPUC DR 855 Attachment A - Revised.

10 *Id.*

11 Staff/402, Scala/5-6, PGE Response to OPUC DR 158, Attachment A and DR 855, Attachment A - Original. The "Original" version of the Company's response to OPUC DR 855 Attachment A provides total transactions using bank card for commercial customers in column H which was corrected to just show transaction fees in the "Revised" response.

adoption by nonresidential customers from approximately five percent to three percent and further, limit cost recovery for the nonresidential FFBC program to $567,000. Staff is concerned the Company's five percent month over month transaction growth forecast is an over projection that does not reflect historical adoption growth in this class of customers.

Further, Staff notes that the forecast is used to calculate per transaction costs and this value is expected to change as a result of Staff's second recommendation to limit the Company's nonresidential FFBC recovery to Schedule 32 transaction costs only. Staff derived the proposed $567,000 cap on nonresidential FFBC cost recovery by averaging the estimated transaction costs from two methods. Both methods approximated Schedule 32 participation in bank card payments using 2022 revenues and bank card transaction forecasts. Please refer to Staff Exhibit 400, Issue 4 on pages 39-41 for details on Staff's discussion on limiting nonresidential FFBC program expense.

Q. Does Staff have any other concerns associated with the Company's proposed Customer Services O&M/NL expense?

A. Yes. Staff is continuing to investigate non-labor expenses the Company has allocated to various marketing department IDs to determine whether the costs are appropriate for FERC account 908. Staff does not see an obvious linkage between the allocated costs and the Code of Federal Regulations description of Account 908 (Customer assistance expenses).[12] In response to a Staff request, PGE attributed increased non-labor costs in Brand/Marketing/Communications expense to outside services, including the reorganization of $300,000 from Segment Marketing.[13] The response did not identify the activities associated with the cost elements, nor did it provide sufficient detail for Staff to conclude that the expenses were correctly categorized by FERC account. To this end, Staff may recommend additional changes to these expenses after further discovery.

Q. Please summarize Staff's proposed adjustment to PGE's Customer Service O&M/NL expense.

A. Staff recommends the Commission:

1. Reduce expenses allocated to Department ID 915: Brand/Marketing/Communication by $889,043 to revise 2022 Test Year expenses to the 2018-2020 three-year average of actual costs.
2. Direct the Company to reallocate, for regulatory purposes, TE related expenses that do not fall within the scope of FERC account 908 to the appropriate accounts and cost categories with amounts subject to the proposed Staff adjustments described in Staff Exhibit 1704.

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12 FERC Uniform System of Accounts, 18 C.F.R. 367.9080 – Account 908, Customer assistance expenses. Available at: https://www.law.cornell.edu/cfr/text/18/367.9080

13 In the Company's original response to OPUC DR 861, Staff/402, Scala/3, PGE stated that the transfer of funds was from Department ID 537, Segment Marketing, which conflicted with the Company's response in OPUC DR 861, Attachment A, where the transfer was said to originate from Department ID 534, Product Marketing. In a revised response, submitted on October 20, 2021, the Company indicated that the Attachment was incorrectly included in the response and should be disregarded.

Q. Does this conclude your testimony on Customer Service O&M/NL expense?

A. Yes.

ISSUE 2. DECOUPLING

Q. Please summarize the Company's proposed changes related to its decoupling mechanism.

A. In its opening testimony the Company requests to extend its Decoupling Mechanism (Schedule 123) thru December 31, 2025, which would otherwise sunset at the end of 2022 in the absence of Commission action. PGE has also proposed two structural changes to Schedule 123. First, PGE proposes to apply the SNA to Schedules 38/538, 47, and 49/549. The Company stated that expanding the SNA to the additional schedules would have the SNA cover all customers 200 kW or less, other than lighting.[14] Second, PGE proposes to allow the company to carry over any amounts exceeding the "two percent limiter" associated with SNA surcharges to the subsequent year or years. PGE stated that allowing the amounts to carry-over will provide symmetry and price change stability as the sur-credit amount is not subject to a limiter the way the surcharge is.

Q. Please describe PGE's Schedule 123 Decoupling Mechanism.

A. The Company provides a description of the SNA and Lost Revenue Recovery Adjustment (LRRA) decoupling mechanisms in its opening testimony.[15] The SNA applies to Schedules 7, 32/532, and 83. The mechanism compares actual weather-adjusted distribution, transmission and fixed generation revenues collected on a volumetric basis with hypothetical revenues that would

[14] PGE/1200, Macfarlane-Tang/41.
[15] PGE/1200, Macfarlane-Tang/40-41.

have been collected with a fixed per customer monthly charge of $71.45 for primary customers and $49.30 for secondary customers under Schedule 7; $111.66 for Schedule 32 customers; and $790.34 for Schedule 83 customers.[16]

The difference between hypothetical and volumetric revenues is collected monthly in a balancing account throughout the calendar year. Balances in the balancing account accrue interest at the modified blended treasury rate. The comparison is intended to allow the Company to recover, where actuals are less than the target-allowed revenues, or refund, where actuals are greater than the target-allowed revenues, the prior calendar year's ending balance in the balancing account. The LRRA is applied to schedules not subject to the SNA and is linked to the reduced kWh sales that result from incremental Energy Efficiency (EE) savings generated through the Energy Trust of Oregon (ETO) programs directed to nonresidential customers other than Schedule 32.[17]

Nonresidential Lost Revenue Recovery amounts will be equal to the reduction in distribution, transmission, and fixed generation revenues due to the reduction in kWh sales as reported to the Company by the Energy Trust of Oregon, resulting from EEMs implemented during prior calendar years attributable to EEM funding incremental to Schedule 108, adjusted for EEM

[16] Dollar values of fixed per customer charge may change as a result of Commission revenue requirement determinations; proposed Schedule 123 revisions include higher monthly fixed charges for all applicable rate schedules.

[17] PGE/1200, Macfarlane-Tang/40.

program kWh savings incorporated into the test year load forecast used to determine base rates.[18] The Lost Revenue Recovery Adjustment may be positive or negative. A negative Lost Revenue Recovery Adjustment for a given test year will occur if kWh savings reported by the ETO, plus the energy savings associated with the conversion to LED street lighting in Schedule 95, are less than those estimated in setting base rates on a per customer basis multiplied by the number of customers.[19]

Q. Please describe the two percent limiter.

A. The Company provides a description of the two percent limiter in its opening testimony.[20] The Company's currently approved Schedule 123 describes the limiter as a special condition where no revision to any SNA or LRRA Adjustment Rate will result in an estimated average annual rate increase greater than two percent to the applicable SNA or LRRA rate schedule, based on the net rates in effect on the effective date of the Schedule 123 rate revisions. Rate revisions resulting in a rate decrease are not subject to the two percent limit.

Q. What happens to the monies that are above the two percent limiter cap that would otherwise be collected in rates?

A. Those monies are not collectible and are removed from the decoupling balance.

Q. How has the Commission approached decoupling historically?

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18 PUC Oregon No. E-18 Ninth Revision of Sheet No. 123-2, PGE Schedule 123.
19 *Id.*
20 PGE/1200, Macfarlane-Tang/41.

A. As states around the country pursued EE as an energy resource, attention was drawn to the unintended disincentive for utilities to promote end-use efficiency because revenues are directly tied to the throughput of electricity and gas sold. Even with incentives to conserve electricity, the utility retained the incentive to sell more electricity.[21] This led several states, including Oregon, to consider alternative approaches that would align utility financial interest with the delivery of cost-effective EE programs.

Decoupling has been perceived as a mechanism that may remove throughput incentives for utilities to sell electricity while maintaining other programs, such as the Energy Trust in Oregon, to promote EE.[22] A properly designed revenue decoupling mechanism should better align the interests of the Company with the energy policies of the Commission and the State.

In 2009, under the authority provided by Commission Order No. 09-020, PGE decoupled revenues from volumetric sales utilizing the balancing account structure of the approved SNA and LRRA mechanisms. During the proceedings prior to the Commission's order, Staff opposed the mechanisms and contended that that PGE will most likely over-collect its fixed costs with the SNA and asserts that the SNA mechanism shifts risk historically borne by shareholders to ratepayers.[23]

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21 Decoupling was first championed by former Maine PUC Commissioner David Moskovitz who observed that with California's fuel cost recovery mechanism, the utilities increased their profits with each additional sale of energy regardless of the cost of additional fuel/energy costs.

22 2007 NARUC Decoupling for Electric and Gas Utilities: FAQ, Available at: Microsoft Word - NARUCDECOUPLINGFINAL.doc.

23 See Docket No. UE 197, Order No. 09-020, at p. 26, https://apps.puc.state.or.us/orders/2009ords/09-020.pdf.

Similar observations had been made by the 2002 Commission around decoupling in general when PGE proposed decoupling in Docket No. UE 362.[24] In Docket No. UE 197, Staff also argued that it was unlikely the removal of the disincentive for efficiency would change PGE's behavior because the ETO functions as the primary entity for encouraging efficiency and conservation separate from utilities.[25] In the order, the Commission stated that PGE could still influence individual customers through direct contacts and referrals to ETO and felt the need to provide incentives for PGE through decoupling.[26] The Commission agreed that under the SNA PGE may be able to recover more than its fixed cost if customer growth exceeds what was assumed in setting rates and conditioned approval on a ten-basis point reduction of the Company's ROE.[27]

In Docket No. UE 215, the Commission approved a stipulated agreement providing a three-year extension of PGE's decoupling mechanism. At that time, the parties also agreed PGE would hire a consultant to evaluate the mechanism during the fifth year.[28] In PGE's 2018 general rate case, docketed as UE 335, PGE proposed to modify its decoupling mechanism to include sales variation associated with weather, eliminate the LRRA, expand the SNA to

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24 See Docket No. UE 126, Order No. 02-633, at p. 5, https://apps.puc.state.or.us/orders/2002ords/02-633.pdf.
25 See Docket No. UE 197, Order No. 09-020, at p. 26, https://apps.puc.state.or.us/orders/2009ords/09-020.pdf.
26 See Docket No. UE 197, Order No. 09-020, at p. 27, https://apps.puc.state.or.us/orders/2009ords/09-020.pdf.
27 See Docket No. UE 197, Order No. 09-020, at p. 28, https://apps.puc.state.or.us/orders/2009ords/09-020.pdf.
28 PGE Response to OPUC DR 362, Attachment A; see Docket Nos. UE 215 and UM 1644, UE 215, COMPLIANCE, 6/6/2013 (state.or.us).

those schedules, and remove the limiter.[29] The Company wanted to remove the weather adjustment from the SNA to allow the full differences in use per customer to be refunded or charged to customers.[30] The changes were opposed by Staff and several intervenors to the rate case, which argued that the proposal did not provide any benefit to customers and shifted risks from the company to ratepayers.[31] The Commission determined the proposal was not sufficiently justified and rejected the Company's proposed changes except to move Schedule 83 customers under the SNA mechanism who were determined to have similar load profiles to customer groups on the SNA.[32] Commission opposition to the recovery of margin losses associated with usage deviations caused by weather in decoupling mechanisms can also be found in Docket No. UE 126, Order No. 02-633.[33]

Q. Is decoupling still needed?

A. The original impetus behind decoupling was to make utilities indifferent to sales by providing them a preapproved level of per customer revenues, regardless of volumetric sales. As described earlier, decoupling removes the throughput disincentive for utilities associated with traditional cost of service regulation in the interest of promoting EE. In the wake of aggressive decarbonization goals,

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29 See Docket No. UE 335, Order No. 18-464, at p. 15, https://apps.puc.state.or.us/orders/2018ords/18-464.pdf
30 *Id.*
31 *Id.*
32 UE 335, Order No. 19-129 at page 16, https://apps.puc.state.or.us/orders/2019ords/19-129.pdf.
33 See Docket No. UE 126, Order No. 02-633, at p. 6, https://apps.puc.state.or.us/orders/2002ords/02-633.pdf.

EE remains paramount and decoupling helps to ensure utilities remain active partners in these efforts.

Q. Please elaborate on how decoupling may promote the State's clean energy goals?

A. According to the Regulatory Assistance Project (RAP),[34] decoupling supports decarbonization through both EE and electrification. Specifically, RAP argues that decoupling prevents utilities from pursuing inefficient electrification by dis-incentivizing increased sales. Decoupling also ensures that customers benefit from the extra revenue associated with electrification. Absent decoupling, additional revenues earned through electrification would not be returned in sur-credits to customers until a subsequent rate case.[35]

Q. Do the benefits associated with additional revenues earned through electrification include increased TE adoption?

A. Yes. To the extent the transition to TE does not fully materialize in fixed per customer charges, decoupling allows customers to receive the benefit from increased volumetric sales resulting from TE and EV adoption.

Q. Which peer utilities currently have a decoupling mechanism in place?

A. Avista Utilities, Cascade Natural Gas Company, and Northwest Natural Gas Company currently have decoupling mechanisms in Oregon. Pacific Power

[34] The Regulatory Assistance Project is an independent, non-partisan, non-governmental organization comprised of former utility and environmental regulators, industry executives, system operators, and other policymakers and officials who provide expertise to energy industry decision-makers and stakeholders on power sector policy, regulation, markets, and more.

[35] https://www.raponline.org/blog/with-the-shift-toward-electrification-decoupling-remains-key-for-driving-decarbonization/

and Idaho Power do not currently have decoupling in Oregon but have mechanisms in other states for which they provide retail service.

Q. Please describe customers that would be impacted if the Company's proposal is approved.

A. Schedule 38 large nonresidential time-of-day standard service is an optional schedule to large nonresidential customers under Schedule 83 Large Nonresidential Standard Service. Any nonresidential customers meeting the following applicable terms can sign up for Schedule 38: 1) served at Secondary Demand Voltage whose Demand has not exceeded 200 kW more than six times in the preceding 13 months and has not exceeded 4,000 kW more than once in the preceding 13 months, or with seven months or less of service has not had a Demand exceeding 4,000 kW; or 2) who were receiving service on Schedule 38 as of December 31, 2015. The customers who sign up for Schedule 38 prefer volumetric energy charges due to low load factors (low energy use relative to demand). Approximately 370 customers receive service under Schedule 38.

Schedule 47 had 2,614 customers as of July 2021. This schedule is applicable to small nonresidential customers for irrigation and drainage pumping and may include other incidental service if an additional meter would otherwise be required. A small nonresidential customer is a customer who has not exceeded 30 kW more than once within the preceding 13 months, or with seven months or less of service has not exceeded 30 kW.

There were 1,437 customers under Schedule 49 as of July 2021. This schedule is applicable to large nonresidential customers for irrigation and drainage pumping and may include other incidental service if an additional meter would otherwise be required. A large nonresidential customer is defined as having a monthly demand exceeding 30 kW at least twice within the preceding 13 months, or with seven months or less of service exceeding 30 kW on any occasion.

Q. Please describe Staff's opposition to PGE's proposal to expand the SNA to Schedules 38/538, 47, and 49/549.

A. In analyzing usage data provided to Staff in a DR,[36] Staff found that of the proposed Schedules to be added to the SNA, approximately 10 percent of the customers comprise approximately 50 to 70+ percent of kWh usage attributed to the schedule. Schedule 538 currently serves two customers, one of whom makes up 73 percent of the usage. There are no customers in Schedule 549. Staff has illustrated the usage distribution of customers receiving service under Schedules 38, 47 and 49 in Staff Exhibit 402, Scala/8.[37]

Staff is concerned that given the billing distributions of customers under these schedules, volatility in usage among high consumption customers amplifies the potential of shifting risk from the Company to the relatively smaller-use customers. This risk could be exacerbated by customers moving between Schedule 47 and 49. In PGE's proposal Schedule 47 has a monthly

[36] Staff/402, Scala/7, PGE Response to OPUC DR 356, Attachment B.
[37] Staff/402, Scala/8, Average kWh usage among PGE Rate Schedules proposed for decoupling.

fixed charge of $89.68 while Schedule 49 is $431.93. PGE indicated that between 2010 and 2020, between two to five percent (61 to 146) of Schedule 47 customers migrated to Schedule 49 each year. The number of customers that migrated each year has generally decreased over the decade, along with the total number of customers on Schedule 47.

During that same period, between five and ten percent (70 to 150) of Schedule 49 customers migrated to Schedule 47 each year. The number of customers that migrated each year, while varied, has not shown a trend up or down. Among the customers who migrated at least once between the two irrigation schedules (1,021), about 60 percent migrated more than once over the 10-year period.[38] To the extent that PGE derives an average fixed cost per customer based on usage, movement of high usage customers will likely result in surcharges for customers remaining on the original Schedule. Given the usage distribution among customers under these schedules, the SNA may effect greater volatility in year over year rates for customers.

This issue is of even greater concern if the Commission were to approve PGE's request to allow for carry over amounts in excess of the two percent limiter on SNA rate increases. Staff argues that including irrigation and drainage schedules in the SNA mechanism does not seem to align with the intended effect of decoupling to remove the throughput disincentive for utilities in the interest of EE. It is Staff's opinion that expanding the SNA to these

[38] Staff/402, Scala/9, PGE Response to OPUC DR 363.

schedules should be rejected as it unnecessarily shifts risk from the Company to customers.

Q. Please describe Staff's opposition to PGE's proposal to allow the carryover of balances associated with SNA under-collections in excess of the two percent limiter, for recovery in subsequent year(s).

A. To remove the two percent cap represents a large shift in risks from the company to customers for such things as a recession. The Company is better able to manage that financial risk than customers.

Additionally, the financial risk is not symmetrical in practice. Based on the Company's testimony, work papers, and relevant DR responses, the likelihood of a surcharge exceeding the limiter is more likely to occur than a sur-credit greater than two percent of annual revenues. Below is a historical look at SNA-related annual percentage rate change and change in revenues:[39]

[39] Staff/402, Scala/10, PGE Response to OPUC DR 364 edited by Staff to reflect 2022 AUT for 2022 revenues.

Table 1. SNA-related annual percentage rate change

Schedule 7	SNA Revenues Collection/(Refund)	SNA Change in Revenues year to year	Total PGE Revenue for Sch 7	Annual % of revenues
2022	$ (16,322,201)	$ (29,817,449)	$ 1,007,609,406	-1.62%
2021	$13,495,248	$9,173,841	$990,265,811	1.36%
2020	$4,321,407	($10,816,429)	$962,612,052	0.45%
2019	$15,137,836	$14,454,810	$919,737,731	1.65%
2018	$683,026	$8,805,885	$895,368,029	0.08%
2017	($8,122,859)	($4,173,437)	$896,272,803	-0.91%
2016	($3,949,422)	($6,517,975)	$819,116,797	-0.48%
2015	$2,568,553	($5,284)	$842,550,702	0.30%
2014	$2,573,837	$2,192,988	$854,204,599	0.30%
2013	$380,849	($3,492,505)	$798,365,078	0.05%
2012	$3,873,353	$12,169,483	$805,712,674	0.48%
2011	($8,296,130)	($8,296,130)	$826,418,008	-1.00%
Schedule 32	**SNA Revenues Collection/(Refund)**	**SNA Change in Revenues**	**Total PGE Revenue for Sch 32**	**Annual % of revenues**
2022	$ 4,013,760	$ 2,454,038	$ 200,687,980	2.00%
2021	$1,559,722	$2,138,755	$189,566,199	0.82%
2020	($579,033)	$1,691,054	$176,047,726	-0.33%
2019	($2,270,086)	($1,139,195)	$179,822,142	-1.26%
2018	($1,130,891)	$322,016	$181,401,021	-0.62%
2017	($1,452,907)	($135,136)	$181,008,170	-0.80%
2016	($1,317,771)	($416,678)	$173,607,884	-0.76%
2015	($901,093)	$1,493,381	$171,963,891	-0.52%
2014	($2,394,474)	$33,142	$169,333,805	-1.41%
2013	($2,427,616)	($4,693,859)	$155,078,953	-1.57%
2012	$2,266,243	$589,903	$160,078,420	1.42%
2011	$1,676,340	$1,676,340	$160,612,801	1.04%
Schedule 83	**SNA Revenues Collection/(Refund)**	**SNA Change in Revenues**	**Total PGE Revenue for Sch 83**	**Annual % of revenues**
2022	$ 5,703,319	$ 2,985,678	$ 285,165,973	2.00%
2021	$2,717,641	$2,717,641	$267,380,667	1.02%

As can be seen in Table 1, SNA collections have not been impacted by the two percent limiter until now. The economic effects of the COVID-19 pandemic on nonresidential usage significantly impacted volumetric revenues in 2020. The SNA associated with the 2020 ending balance are recovered in 2022. 2022 SNA collections triggered by the lower volumetric revenues in 2020 for Schedule 32 and Schedule 83 have been highlighted in Table 1. In the absence of the limiter, actual 2020 decoupling results would have resulted in approximately $10 million to be collected from Schedule 32 customers and $7.8 million from Schedule 83 customers. Table 2 shows a comparison of Schedule 32 and Schedule 83 authorized recovery under the SNA with and without the limiter.

Table 2. Comparison of Schedule 32 and Schedule 83 SNA recovery

	SNA Revenues Collection	SNA Change in Revenues	Total PGE Revenue for Sch 32	Annual % of revenues
Schedule 32	$ 4,013,760	$2,454,038	$ 200,687,980	2.00%
Schedule 32	$10,075,100	$2,454,038	$ 200,687,980	**5.02%**
Schedule 83	$ 5,703,319	$2,985,678	$ 285,165,973	2.00%
Schedule 83	$ 7,807,542	$2,985,678	$ 285,165,973	**2.74%**

Staff notes that PGE clarified that if the carryover were authorized, the two percent rate adjustment cap would apply to amortization amounts on an individual schedule basis, and that any amount collected from a schedule subject to the decoupling mechanism in any given year would never exceed two percent.[40]

Nonetheless, this assurance from the Company is narrow as carryover balances would remain in the balancing account and continue to earn interest at the modified blended treasury rate and could potentially subject customers to prolonged bill increases or offset refunds that would have been credited had the limiter disallowed carryover into years where over-collections were returned. As PGE indicated in its opening testimony, the limiter is intended to

40 Staff/402, Scala/11, PGE Response to OPUC DR 638.

be a “circuit breaker.” Staff agrees with this characterization and finds the limiter is still an appropriate inclusion in the mechanism.

Q. Please explain why Staff supports extending the decoupling mechanism thru 2025.

A. Staff recognizes there are continuing benefits to the mechanism to the extent it continues to remove the Company’s incentive to increase volumetric sales and deemphasize energy efficiency investments. Staff also acknowledges the benefit decoupling affords to low-income rate payers who receive the sur-credits associated with over-collections from TE adoption. To this end, Staff is supportive of continuing the mechanisms, as currently structured, thru 2025.

Q. Please summarize Staff’s proposed adjustment to PGE’s changes to the Company’s Sales Normalization Adjustment (SNA) Decoupling mechanism.

A. Staff recommends the Commission:

1. Approve PGE’s request to extend Schedule 123 thru December 31, 2025.
2. Reject PGE’s proposal to apply the Sales Normalization Adjustment (SNA) to Schedules 38/538, 47, and 59/549.
3. Reject PGE’s proposal to allow the Company to carry over charges in excess of the 2 percent limiter for recovery in subsequent years.

Q. Does this conclude your testimony on Decoupling?

A. Yes.

ISSUE 3. LIGHTING

Q. Please summarize the Company's Street and Area Lighting pricing proposal.

A. PGE has requested to update Schedule 15, Outdoor Area Lighting Standard Service Cost of Service (COS) and Option A[41] and Option B[42] for Schedule 95, Street and Highway Lighting New Technology COS to create wattage buckets for Light Emitting Diode (LED) lighting options. The proposed wattage buckets mirror Schedule 95's Option C[43] LED buckets. The Company has also proposed corresponding buckets based on the cost of light and maintenance for the purposes of non-energy charge per bulb. This would only impact LED bulbs.

Q. Please describe Staff's review of PGE's proposal.

A. Staff investigated several elements of the proposal, including, but not limited to the types of actual customers receiving service under the affected Schedules[44]; the methodology used by the Company to create the wattage buckets[45]; bill and revenue impacts[46]; and LED conversions across Oregon municipalities[47]. Staff did not identify any concerns in its investigation and found PGE's

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41 Option A provides electricity service to luminaires that are purchased, owned, and maintained by the Company with attachment to Company-owned poles at the monthly Option A rate applicable to the installed type of light.

42 Option B provides electricity service to Customer purchased and owned luminaires at the monthly Option B rate applicable to the installed type of light. The Company provides for maintenance only to luminaires and related equipment at the applicable monthly Option B rate.

43 Option C provides electricity service to luminaires that are purchased, owned and maintained by the Customer and installed on non-Company owned poles or Company-owned distribution poles.

44 Staff/402, Scala/12, PGE Response to OPUC DR 441

45 Staff/402, Scala/13, PGE Response to OPUC DR 446.

46 Staff/402, Scala/14, PGE Work papers Exhibit 1100, 2022GRC Street & Area Light model.

47 Staff/402, Scala/15, PGE Response to OPUC DR 653, Attachment A.

proposed changes favorable to simplifying rates for customers receiving service under these schedules.

Q. What is the methodology used by the Company to create wattage buckets under these Schedules?

A. The wattage buckets mirror the ones used in the currently approved tariff for Schedule 95 Option C customers. The methodology is based on lights that have a similar lumen output and the same material and maintenance cost. The buckets did not lead to any redistribution of maintenance or fixture costs.[48]

Q. What are the advantages of utilizing wattage buckets for LED bulbs?

A. The proposed change will eliminate the need for PGE to continually add new lights to the Company's billing system, asset management system, and tariff.[49] Efficiencies in LED technology are rapidly reducing wattages for the same number of nominal lumens. Creating buckets will allow the approved tariff to remain relevant amid wattage efficiencies and simplify the number of billing options for customers, thus reducing the complexity of their monthly statement.

Q. Does the Company's proposed changes demonstrate the attributes of a sound rate structure?

A. Yes. When considering the reasonableness of the proposal, Staff looked at how the proposal might align with attributes identified by James C. Bonbright in *Principles of Public Utility Rates.* In the text, Bonbright states that rates should have practical attributes, including simplicity, understandability, public

48 Staff/402, Scala/13, PGE Response to OPUC DR 446.
49 Staff/402, Scala/16, PGE Response to OPUC DR 442.

acceptability, and feasibility of application. Staff finds that for the reasons discussed earlier in this testimony, PGE's proposal to create wattage and maintenance buckets for LED bulbs promotes these attributes to the benefit of both customers and the utility.

Q. Please summarize Staff's proposed adjustment to PGE's changes to Street and Area Lighting pricing.

A. Staff is not recommending any changes to the Company's Street and Area Light proposal at this time.

Q. Does this conclude your testimony on Street and Area Lighting?

A. Yes.

ISSUE 4. FEE FREE BANK CARD PAYMENT OPTION

Q. Please summarize the Company's FFBC proposal.

A. PGE has asked to expand fee free bank card payment options to nonresidential customers. The Company wants to update Customer Accounts expense to reflect: (1) increased adoption in the residential FFBC program; and (2) expansion of the FFBC option to commercial customers.

Q. Please describe the increased costs associated with bank card payment options.

A. In the Company's opening testimony, PGE indicated that the increased adoption costs associated with bill payments made by bank cards is approximately $0.5 million attributed to the residential program and $1.1 million to expand the program to all commercial customers. However, in the Company's response to OPUC DR 382, PGE revealed that it had misstated the total increase associated with both the residential and commercial programs.[50] The costs associated with increased adoption in the residential program is $0.4 million and expansion of the commercial program has incremental costs of $1.3 million. Adoption forecasts were developed in partnership with the Company's vendor, utilizing peer utility adoption curves; and PGE's 2020 and 2021 actual adoption rates with 2020 forecasts.[51]

Q. Please describe the Company's 2022 Test Year forecast for bank card payment adoption.

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[50] Staff/402, Scala/17, PGE Response to OPUC DR 382.
[51] PGE/500, Bekkedahl-McFarland/20.

A. The Company forecasted the number of residential bank card transactions to increase at a rate of 0.2 percent each month in 2022.[52] For the number of nonresidential bank card transactions, the Company forecasts a month over month increase of five percent.[53] PGE forecasts FFBC costs for residential adoption in 2022 to be $2,209,000 and nonresidential adoption approximately $1,474,000.

Q. How does the forecast compare to historical adoption rates of the bank card payment option?

A. The forecasted costs associated with the FFBC program represent a $345,000 and $1,306,000 increase from the 2020 Base Year for residential and nonresidential FFBC costs, respectively. For the adoption rate forecast, Staff reviewed bank card payment activity among residential and nonresidential customers between 2014 and the Test Year 2022. The number of residential bank card transactions reported in the Company's response to OPUC DR 158 show that the number of residential transactions fluctuate month over month but have generally increased since the fee free program's inception at the end of November 2014.[54] Month over month increases in residential transactions for the Base Year 2020 averaged 3.47 percent, which is significantly higher than the 0.2 percent Test Year forecast. Nonresidential bank card transactions in the Base Year 2020 averaged 7.2 percent thus exceeding the Test Year forecast.

52 Staff/402, Scala/4, PGE Response to OPUC DR 855, Attachment A - Revised.
53 *Id.*
54 See PGE UE 262 and UE 283.

Staff considered that social distancing and business closures associated with the COVID-19 pandemic may have caused adoption rates to exceed historical averages in 2020 and found that the three-year average growth rate for residential transactions between January 2017 and December 2019 was 1.36 percent. For nonresidential transaction, this same time frame yielded a three-year average of 1.78 percent.[55] The Company's forecast for residential bank card transactions assumes the growth in 2020 and 2021 does not recede to pre-pandemic values but reduces month to month adoption rates below historical averages. Staff finds this approach reasonably reduces the risk of over forecasting adoption rates in the Test Year.

Staff Exhibit 402, Scala/18 provides PGE residential and nonresidential historical actuals and Test Year projections.[56] In the larger chart in the exhibit, PGE's forecast appears above historical trends, however, if the same analysis is applied to adoption rates over the last three years, starting in January of 2019, as is done in the smaller chart, the residential forecast appears reasonably consistent with growth pre, mid, and post pandemic.

Nonresidential transactions are more challenging to forecast because the Company's offering of the FFBC option to nonresidential customers and the pandemic occurred at the same time. PGE is forecasting aggressive adoption rates in 2022 compared to nonresidential use of the program historically. In opening testimony, the Company indicated that the lack of a fee free bank card

55 Nonresidential PGE customer bank card transactions were subject to a fee prior to March of 2020.

56 Staff/402, Scala/18; PGE Bank Card Transactions.

transactions has frequently been a source of frustration for some nonresidential customers.[57] Further, bank card payment adoption among nonresidential customers has likely increased due to the same pandemic related conditions faced by residential customers.

To these ends, a higher adoption rate for nonresidential customers in the FFBC program does not contradict recent trends. That being said, Staff is cautious of a five percent month to month increase in nonresidential transactions, particularly given the tendency by utilities to over project adoption rates in bank card transactions and the return to pre-pandemic business practices by many nonresidential customers.

Q. Does Staff find the bank card payment adoption rates for residential customers reasonable?

A. Historically, the Company has over-projected bank card transactions by residential customers.[58] However, according to information provided by the Company, actual monthly residential bank card transactions have exceeded projections since January 2020. As indicated earlier, Staff attributes a degree of increased adoption to the need for customers to utilize electronic payment as a means to pay their bills amid social distancing regulations and preferences associated with the COVID-19 pandemic.[59]

Further, Company closures of in-person pay stations further limit alternative means of payment. In materials provided to Staff, **[BEGIN HIGHLY**

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57 PGE/500, Bekkedahl-McFarland/18.
58 Staff/402, Scala/5, PGE Response to OPUC DR 158, Attachment A
59 https://link.springer.com/article/10.1057/s41264-021-00104-1

CONFIDENTIAL] [redacted][60] **[END HIGHLY CONFIDENTIAL]** Staff recognizes that the world is still in the midst of the pandemic. The risks associated with COVID-19 and highly contagious variants of the virus continue to foster interest in alternatives to in-person transactions and money handling.[61]

To this end, Staff finds it reasonable for the Company to assume customers will continue to adopt bank card payment options at an increasing rate. This rate is likely to slow as the economy continues to recovery and more individuals return to in-person settings, however because the forecast is lower than historical averages, Staff finds this rate reasonably approximates increased adoption and limits the risk of over projecting. As such, Staff does not oppose PGE's Test Year forecast of a 0.2 percent month over month increase in residential customer bank card transactions

Q. Does Staff find the per transaction fee for residential customers reasonable?

Staff confirmed that the transaction fee of $1.07 **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** at the residential customer account level is consistent with the Company's executed agreement with its third-party payment processing vendor.

60 Staff/404, Scala/1-5, PGE HIGHLY CONFIDENTIAL Response to OPUC DR 849.
61 https://link.springer.com/article/10.1057/s41264-021-00104-1

Historically, per transaction costs for residential bank card transactions were approximately $1.49. The executed agreement with the third-party processor is lower, however Staff notes that this cost is born by all customers rather than just those utilizing the bank card payment option. A rough estimate of residential use of bank card payment options can be derived by assuming one transaction per customer divided by the total number of residential customers. As of April 2021, that methodology would indicate a penetration rate of 19.23 percent.

That being said, residential customer adoption is expected to increase and the fee free payment option has been available to customers for almost seven years. As such, Staff does not recommend any changes to the residential program and finds the $1.07 per transaction cost to be reasonable.

Q. Does Staff find the bank card payment adoption rates for nonresidential customers reasonable?

A. PGE did not forecast nonresidential bank card payments prior to PGE's decision to offer the fee free option in 2020. To this end, Staff was unable to compare historical deltas between projected nonresidential transactions and actual nonresidential transactions. Performing a similar rough estimate of program penetration by dividing the number of bank card transactions by the most recently available number of nonresidential customers, Staff observed a very slow uptake in nonresidential use of bank cards for payment with adoption at less than two percent through April of 2020.

However, nonresidential bank card transactions increased more consistently and rapidly over the next 12 months. This can likely be attributed to a combination of the aforementioned COVID-19 pandemic effects on in-person and paper transactions as well as the expansion of the fee free option to nonresidential customers. Between May of 2020 and April of 2021, penetration estimates increased from approximately 2 percent to almost 6 percent.

Q. **When did the Company begin offering fee free bank card payments to nonresidential customers?**

A. The Company did not begin offering fee free bank card payment options to nonresidential customers until March of 2020. The Company began offering the fee free option to nonresidential customers as a means of alleviating financial stress during the COVID-19 recession, for nonresidential customers.[62] Prior to this offering, nonresidential customers were required to pay a $4.95 fee to pay with a bank card.

In materials provided by the Company, **[BEGIN HIGHLY CONFIDENTIAL]** [redacted].[63] **[END HIGHLY CONFIDENTIAL]**

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[62] PGE/500, Bekkedahl-McFarland/18.
[63] Staff/404, Scala/6-37, PGE Highly Confidential Response OPUC DR 852-A.

Q. What are the terms of the executed agreement between PGE and the third party payment processor as it relates to effective date and fees?

A. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted].

[redacted].[65] **[END HIGHLY CONFIDENTIAL]**

Q. Which nonresidential schedules are eligible for fee free bank card payments?

A. Per the negotiated contract with Visa payment processor, PGE must treat all commercial customers under a single payment fee structure. As a result, fees are not specific to commercial customers schedules and all commercial rates are charged the same fee.[66]

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64 An overview of PGE's Electronic Payment Redesign vendor selection process prior to executing an agreement with **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** can be found in Staff/403, Scala/1-6, PGE's response to OPUC DR 414, Attachment A.

65 Staff/404, Scala/6-37, PGE HIGHLY CONFIDENTIAL Response OPUC DR 852-A.

66 Staff/402, Scala/19, PGE Response to OPUC DR 381.

Q. Did the Company receive Commission approval to expand the fee free option to nonresidential customers?

A. No. Commission Order No. 15-356 states, "Parties agree that PGE would not launch a commercial FFBC program in 2016 and would notify Staff no less than forty-five days before launching a commercial FFBC program."

Q. Did the Company abide by the previously-mentioned agreement to notify Staff 45 days prior to launching a commercial FFBC program?

A. No. Although it appears that PGE may have notified a PUC Staff via a phone call, it was not until after the Company began offering the fee free option to nonresidential customers.[67] In Staff's review of the Company's response to OPUC DR 849, Staff did not find evidence that PGE did not initiate communications with Staff about expanding the program. At best, Staff found that the Company mentioned fee free options being made available to nonresidential customers in response to a separate line of questioning posed to the Company from Staff in May of 2020.[68] In response to a separate DR, PGE indicated that due to the urgency of the recession caused by COVID-19, PGE could not give advance notice of the program.

The Company could have notified Staff when it began discussions with the Vendor, or when the Company decided it was going to contact the vendor,

[67] We have polled PUC Staff members and only Phil Boyle of Consumer Services vaguely remembers a call about this subject. No one else was notified: not counsel, the Utility Program Director nor OPUC COO Michael Dougherty. Staff could not find anything in writing beyond a tangential reference to the FFBC expansion to nonresidential customers in a reply the Company provided to a broad line of questioning from OPUC Consumer Services.

[68] Staff/404, Scala/1-5, PGE HIGHLY CONFIDENTIAL Response to OPUC DR 849, Attachment A.

but PGE did not. Staff was not contacted until after the Company had executed an agreement with the Vendor. Further, PGE did not discuss with Staff whether Staff had any concerns with executing a five-year agreement for a service yet to be authorized by the Commission.

Q. Is the Company pursuing recovery of the costs associated with the advanced offering of FFBC payment options to nonresidential customers in response to the pandemic?

A. No. The Company indicated that because the program was initiated between general rate case proceedings, the costs of the program were born by the shareholders, not ratepayers.[69]

Q. Could the Company benefit from offering the Commercial Fee Free Program even if it absorbed the fee payment charges?

A. Potentially yes. It is unclear how many commercial customers would have simply not paid their bills had they no credit card option. If customers were able to pay their bills by using the credit card option, the Company was better off in that alternative even absorbing the credit card payment fee.

Q. How does the Company typically recover costs associated with the FFBC program?

A. Currently, the costs of the fee free bank program are included in rates charged to all retail customers. The costs are allocated across all customers based on the percentage of customers enrolled in paperless billing. The program costs are weighted toward customer classes enrolled in paperless billing.

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[69] Staff/402, Scala/20, PGE Response to OPUC DR 380.

Residential and small nonresidential customers are allocated the majority of the costs with approximately 93 percent of the costs being allocated to Schedule seven customers and approximately six percent being allocated to Schedule 32 customers.[70]

Q. Does the Company propose to change the cost recovery practices to reflect greater nonresidential adoption?

A. No. PGE proposes to allocate the costs of the commercial fee free bank program in the same manner as the existing program.[71]

Q. Does Staff find this cost recovery practice appropriate?

A. As FFBC program costs increase relative to nonresidential adoption, Staff finds current recovery practices are no longer equitable across residential and nonresidential customers. The reduced nonresidential adoption rate assumptions proposed by Staff and referenced above in the discussion of Customer Service expense are intended to capture some of the volatility seen in historical adoption rates while following the trend line associated with growth in the last three years, beginning January 2019. The recovery cap is intended to limit the rate impacts on residential and nonresidential customers.

As discussed earlier in this testimony, PGE's nonresidential program was initiated prior to Commission notice and approval despite the requirement memorialized in Commission Order No. 15-356. Expansion of the FFBC program has tripled per transaction costs associated with nonresidential use.

[70] Staff/402, Scala/21, PGE Response to OPUC DR 376.
[71] Staff/402, Scala/22, PGE Response to OPUC DR 378.

Staff does not find recovery of these associated costs in rates equitable to residential and smaller nonresidential customers who would be expected to share the higher transaction fees. Staff also lacks sufficient evidence from the Company warranting the spike in transaction costs relative to historic actuals.

Q. Does Staff have any other concerns it wishes to express regarding this program?

A. Yes. In a response to Staff's inquiry as to the types of FFBC users, the Company provided "Significant Attributes of Fee-Free Bank Card Use" and "Uncommon Attributes of Fee-Free Bank Card Users" tables submitted in the Program's 2015 report, updated for 2020.[72] Staff found that customer characteristics typically associated with low-income customers (e.g. TPA, EA, blue collar occupations) had low representation among users. Staff also found that representation of these characteristics among users decreased between the 2015 report and the 2020 update.

To this end, Staff wishes to point out that costs associated with the program are spread across all customers, including low-income customers that, based on this data, may be less likely utilize bank cards for payment and benefit from the fee free offering. Should that be the case, the program would effectively provide a subsidy to non-low income customers, thanks to low-income customers, by spreading the costs across all customers, including low-income, non-users.

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72 Staff/402, Scala/23-24, PGE Response to OPUC DR 373.

Q. Is Staff proposing any changes to the residential FFBC program in response to the aforementioned equity concerns?

A. Yes. The fee free charge program should be spread across all customer classes on an equal percent of revenue basis. To the extent this program avoids non-bill payment, and thereby reduces the rate of uncollectibles, it benefits all customers. Staff remains concerned that this program harms low-income customers. However, with the change to allocate the costs across all schedules on an equal percent of revenues basis, this should reduce the harm to low-income customers.

Q. What is Staff's proposal regarding the FFBC program expansion?

A. As outlined earlier in testimony, Staff is proposing to limit recovery associated with nonresidential FFBC adoption to $567,000. This amount is intended to reflect a three percent month to month adoption rate in the Test Year and recover only those costs associated with Schedule 32 customers. Staff calculated the $567,000 cap on nonresidential FFBC cost recovery by rounding up the average the estimated transaction costs from two Staff generated methods.

The first calculates an average number of transactions per month using the three percent growth forecast by Staff and comparing that value (9,059) to the number of Schedule 32 customers reported by the Company in the 2022 AUT (94,649). The resulting 9.57[73] percent is then used as a proxy value for

[73] Staff notes that the 9.57 percent value was calculated using a numerator based on a forecast of all nonresidential bank card transactions; however the Company was unable to distinguish

Schedule 32 bank card payments. The 9.57 percent is multiplied by the percentage by the 2022 AUT Schedule 32 revenues ($200,687,980) for an estimate $19,208,673 in Schedule 32 revenues paid using bank card. The transaction fee of **[BEGIN HIGLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** in forecasted transaction fees.

The second approach begins similarly, up through the calculation of Schedule 32 revenues paid using bank card. It then extrapolates Staff's three percent growth forecast from number of transactions to total transaction dollars, for a Test Year total of $44,659,076 nonresidential payments by bank card. Using the dollar value of Schedule 32 bank card transactions as a percentage of total nonresidential transactions, Staff computed 43.01 percent. Staff then took the Company's forecasted $12.12 per transaction cost and multiplied by the forecasted annual transactions for the test year (9,059 x 12 = $1,317,541). This amount represented total nonresidential transaction costs and was multiplied by 43.01 percent to derive the Schedule 32 share of transaction costs, resulting in $566,714. The average of Staff's two approaches is approximately $567,000.

Staff also believes the Company should limit the fee free program recovery Schedule 32 transactions within a $1,500 limit[74] and a velocity of one

[74] Per UE 394 PGE Response to OPUC DR 849 the $1,500 limit will capture **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL].**

payment per month. However, at the time this testimony was written, the Company had not been able to provide Staff with nonresidential bank card transaction data by Schedule and indicated that nonresidential transactions could not be parsed out in such a way. To this end, Staff does not have a distribution of Schedule 32 transactions that would provide sufficient information to estimate the effect of a $1,500 limit on transaction costs. Staff also notes that PGE has entered into an executed agreement with the third party vendor, prior to review and approval by the Commission, where the transaction limits differ from Staff's recommendations and the vendor does not distinguish between nonresidential rate schedules.[75] Staff acknowledges that the executed agreement may limit FFBC programmatic changes in the near term; however Staff points out that its recommendation is directed at what costs the Company may recover in rates and does not necessarily impact the services PGE has agreed to offer in advance of Commission approval.

In addition to the aforementioned recovery limit, Staff recommends the Commission require PGE to notify the Commission of any proposed changes to the FFBC program with the Commission for approval. This will afford the Commission the opportunity to understand the terms under which PGE plans to offer FFBC payment options to customers.

Q. Please summarize Staff's proposed adjustment to PGE's proposed expansion of the FFBC program.

A. Staff recommends the Commission:

[75] Staff/402, Scala/26-27, PGE Response to OPUC DR 852.

1. Reduce the Company's proposed 2022 Test Year expense for nonresidential FFBC program by $907,000 to limit the Company's recovery for nonresidential transaction fees to $567,000.
2. Limit future PGE recovery of nonresidential fee free bank card payments to once per billing period with a payment cap of $1,500.
3. Limit PGE recovery of nonresidential fee free bank card payment options to Schedule 32 customers
4. Require the Company to notify the Commission any proposed changes to the FFBC program in advance of implementation.
5. Change the method of allocating the costs of the FFBC program from allocating the costs across all customers based on the percentage of customers enrolled in paperless billing to across all customer classes on an equal percent of revenue basis.

Q. Does this conclude your testimony on FFBC payment options?

A. Yes.

ISSUE 5. HB 2475 IMPLEMENTATION

Q. Please briefly describe House Bill 2475.

A. House Bill 2475 was signed into law in 2021, creating new provisions and amending ORS 756.010, 757.072, and 757.230 to include definitions for "environmental justice" and environmental justice communities" in ORS governing the Commission and utilities it regulates. Section 2 of the act amends ORS 757.230 to allow consideration of differential energy burdens on low-income customers and other economic, social equity or environmental justice factors that affect affordability for certain classes of utility customers in rate design.

Section 3 of the act provides intervenor funding agreements for organizations that represent low-income residential customers and residential customers of environmental justice communities. Section 7 of the Act allows the Commission to address the mitigation of energy burdens through bill reduction measures, including, but not limited to, demand response or weatherization.

Q. Has the Company proposed rates based on differential energy burdens?

A. PGE has not proposed and differential rate structures in UE 394 specific to HB 2475.

Q. Please summarize Staff's proposal to implement differential rates in UE 394.

A. Staff is not recommending the Commission require any action to implement equity based differential rate designs related to HB 2475 in PGE's 2022 General Rate Case, UE 394.

Q. Why has Staff not made a recommendation for differential rates in its proposal?

A. Staff wishes to highlight the intentionality of HB 2475 to include energy justice communities in consideration of differential rates for energy burdened customers. The Act does not specify to what extent differential rates may address energy burden nor the method in which differential rates should be administered. Staff recognizes the significance of this legislation and the opportunity it provides to bring broad stakeholder and community voices to the table in a joint effort to meaningfully address energy burden in Oregon.

At this time, intervenor funding is not available to stakeholders and representatives of the energy justice community. Action taken in advance of this funding, limits participation in a process that should exemplify equity and inclusion. Further, action taken in advance of intervenor funding, forces stakeholders to react to decisions or proposals developed in their absence rather than giving the community the opportunity to play a meaningful role from start to implementation.

Q. Does Staff have a plan outside of UE 394 to begin HB 2475 implementation?

A. As indicated earlier in Staff's testimony, the desire is for stakeholders to have a voice at the table start to implementation. To this end, Staff plans to schedule a workshop with the utilities and stakeholders to inform next steps and to create a timeline and workflow for implementation to begin in January, 2022. In the event advocates and stakeholders express a desire to take immediate action, interim or otherwise, in advance of a broader implementation process, Staff will work responsively to develop a plan that accommodates this preference. The initial meeting is meant to be limited to the discussion on process and pathways forward. Staff intends to reserve material discussions on differential rate design and program principles and standards until when stakeholders and the EJ community are able to participate fully.

Q. What types of data does Staff believe is necessary to design impactful rates for energy burdened communities?

A. Staff's work in Docket No. UM 2114, the investigation into the economic impacts of the COVID-19 pandemic on utility customers, revealed a number of gaps in data available to analyze affordability and levels of need in Oregon. Staff will work with the utilities and EJ community do determine the necessary data requirements to ensure programs are targeted and the impacts of the rate design are measurable. At a minimum, Staff anticipates the need for household income levels, housing type, number of dependents and demographic data such as race and age. Other data points might include highest level of education achieved and/or a socioeconomic status metric, broadly.

At this time, Staff is not implying that some or all of this data should come directly from the utilities or that we must have all the data before any action takes place. There are a number of public and private organizations that collect such data points and in the interest of HB 2475, it may be appropriate to start looking at how the Commission, utilities, and EJ community might leverage their positions to partner with these organizations and access said data. Beyond customer data, it will be essential that process participants have a full understanding of rate implications associated with a variety of differential design options. Staff envisions a matrix of cost/benefit analyses to compare the degree of assistance provided to the level of cost required to implement and administer. To this same end, a qualitative view of various program designs will be valuable in determining how prescriptive to be prior to utilities filing differential rate designs.

Q. What are Staff's expectations around HB 2475 in 2022?

A. Staff anticipates that stakeholders will provide meaningful insight at the initial planning workshop in terms of pathways forward. That being said, Staff has heard and considered issues including but not limited to, provisions for interim relief in the near term, partnerships with research organizations to allow for a full-scale investigation on Oregon energy burden and differential rate design, cost containment and exploration of rate impacts, and bundling discounts with energy efficiency programs.

There will likely be the need for topical workshops that begin broadly and distill down specific issues once a unified and equitable set of goals, standards, and limitations have been established. It is not Staff's intention to protract the implementation of HB 2475 beyond what is necessary to collaboratively design foundational elements of differential rates that meaningfully address energy burden.

Q. Does this conclude Staff's testimony on HB 2475 implementation as well as your testimony in general?

A. Yes.

CASE: UE 394
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME: Michelle Scala

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Strategy Integration Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: BA Economics, University of Hawaii, Manoa; Honolulu, Hawaii
BA Political Science, University of Hawaii, Manoa; Honolulu, Hawaii

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since July 2020 as a Senior Utility Analyst. I initially began work at the Commission in the Energy Rates, Finance and Audit Division and later transitioned to the Strategy Integration Division upon its inception. I have over eight years of experience in policy analysis and program evaluation for state and local government. My work prior to the Commission included serving as a Senior Fiscal Analyst at the Oregon Department of Human Services and Economist at the Oregon Employment Department. Prior to that I was employed at the Hawaii State Legislature as the Senior Analyst to the Senate Committee on Ways and Means.

CASE: UE 394
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support of Opening Testimony

October 25, 2021

**“PGE Workpapers_500 Non Conf/
Cust Acct-Svcs Work paper_06.18.21”**

is filed in electronic format

“PGE Response to OPUC DR 864 Attachment A”

is filed in electronic format

October 5, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 861
Dated September 21, 2021

Request:

Please describe any relevant changes or growth in Company marketing activities that tie to increased costs observed in FERC account 908 (NL), under the following department IDs:

a. 915 Brand/Marketing/Communications;
b. 538 Residential Marketing P.O.;
c. 534 Product Marketing; and
d. 537 Segment Marketing.

Response:

a. The majority of increases in department 915 account for labor and labor loadings as well as costs for limited duration employees hired to attract labor in a tight labor market. Additionally, approximately $300,000 of costs were transferred from department 537 – Segment Marketing to this department due to reorganizations in the company.
b. The growth observed in FERC account 908 (NL) for department 538 is related to the Flexible Load Portfolio. As the Demand Response portfolio triples from 2020 to 2024, more staff will be needed to support current as well as new offerings such as Energy Partner growth, Single Family Water Heaters, Transportation Electrification Residential Demand Response, New Construction and Retrofit electrification bundles, and growth in Time of Use, Peak Time Rebates, and Thermostat Programs. For further information, please see PGE direct testimony, Exhibit 500.
c. The growth in Department 534 is associated with our Electric Transportation projects. For further information, please see PGE's response to OPUC Data Request No. 747.
d. See part a above.

“PGE Response to OPUC DR 855 Attachment A - Revised”

is filed in electronic format

“PGE Response to OPUC DR 158 Attachment A”

is filed in electronic format

**“PGE Response to OPUC DR 855
Attachment A - Original”**

is filed in electronic format

**"PGE Response to OPUC DR 356
Attachment B"**

is filed in electronic format


Average kWh usage among PGE Rate Schedules
Proposed for decoupling
Rate Schedule
49
47
38
100
50,000
125,000
kWh (Usage)
RATE
38
47
49

August 20, 2021

To: Paul Rossow
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 363
Dated August 6, 2021

Request:

For the time period 2010 through 2020, please provide the following:

a. The number of customers that migrated from Schedule 47 to 49.

b. The number of customers that migrated from Schedule 49 to 47.

Response:

Between 2010 and 2020, between 2-5% (61 to 146) of Schedule 47 customers migrated to Schedule 49 each year. The number of customers that migrated each year has generally decreased over the decade, along with the total number of customers on Schedule 47.

During that same period, between 5%-10% (70 to 150) of Schedule 49 customers migrated to Schedule 47 each year. The number of customers that migrated each year, while varied, has not shown a trend up or down. Likewise, the number of customers on Schedule 49 has been more consistent year-over-year, compared to Schedule 47.

Among the customers who migrated at least once between the two irrigation schedules (1,021), about 60% migrated more than once over the 10-year period.

Attachment A provides the detailed calculation.

“PGE Response to OPUC DR 364 Attachment A (Staff edits)”

is filed in electronic format

September 17, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 638
Dated September 3, 2021

Request:

What is the maximum percentage increase in rates, taking into account charges from any SNA balancing account amount and any previous carry-over(s)? For example, is the 2 percent limitation applicable separately to the current SNA balance and any carry-over amounts, or is it the maximum percentage rate change a rate schedule may experience associated with the proposal inclusive of all related charges?

Response:

The 2 percent rate adjustment cap applies to amortization amounts on an individual schedule basis. It applies to the current SNA balance and any carry-over amount inclusive of interest. For example, the decoupling amount collected from Schedule 7 customers via Schedule 123 in any given year would never exceed 2 percent.

August 27, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 441
Dated August 13, 2021

Request:

For customers receiving service under Schedules 15, 91, or 95, please:

a. Describe significant customer characteristics under each schedule; e.g.
    i. Composition and diversity of multiple bulb types under a single account;
    ii. Expected monthly kWh usage by bulb type; and
    iii. Type(s) of entities that receive service under each of these schedules

Response:

Schedule 15 customers tend to be residential customers with area lights on their property or commercial customers with area lighting in parking lots or other areas. Schedule 91 and 95 customers are municipalities or agencies of federal or state governments, and they have a mix of both Schedule 91 and 95 lights. This is because Schedule 91 represents old lighting technologies (i.e., anything that is not an LED light), and Schedule 95 is exclusively LED lighting. Municipalities tend to have a mix of these lights that is unique to each customer, so there is not a customer that is representative of each rate since these customers have a unique mix of both rates and lighting options. The expected monthly kWh usage is listed in the tariff by light type and is based upon a burning hours study that estimates the amount of time that the light will be on based on the number of daytime and nighttime hours throughout the year. Expected monthly kWh usage by bulb type can be found in the work papers to PGE Exhibit 1100 in the file titled “2022GRC Street & Area Light Model” in tabs “Exh-p2-p4" and “Exh-p7.”

August 27, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 446
Dated August 13, 2021

Request:

Referring to PGE/1200 Macfarlane-Tang/36 starting at line 5;

a. Please provide additional detail explaining the methodology PGE proposes to use to create buckets based on the cost of light and maintenance for the purposes of the non-energy charge per luminaire.

b. Please specify the work paper file name and tabular location(s) of the proposed cost of light and maintenance buckets.

c. Please explain if/how the non-energy charge buckets work with and/or correspond to the wattage buckets proposed.

Response:

a. The methodology PGE is proposing to use to create buckets is based upon lights that have a similar lumen output and the same material and maintenance cost.

b. The maintenance and light costs can be found in the work papers named “2022GRC Street & Area Light Model” located in the non-confidential work papers for PGE Exhibit 1100. The tabs labeled “wp-page5” and “wp-page15-21” show the investment rate for the fixture, as well as the maintenance rate and the energy rate. The numbers in these files come from the maintenance and investment cost studies which may also be found in the non-confidential work papers for PGE Exhibit 1100.

c. The non-energy charge buckets work with the wattage buckets because the buckets are based on lights that have the same fixture and maintenance costs. The buckets did not lead to any redistribution of maintenance or fixture costs.

**“PGE 2022GRC
Street & Area Light Model”**

is filed in electronic format

"PGE Response to OPUC DR 653 Attachment A"

is filed in electronic format

August 27, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 442
Dated August 13, 2021

Request:

Please describe how the proposed change will affect PGE operations and procedures with regard to offering and managing service under Schedules 15, 91, and 95.

Response:

The proposed change will eliminate the need to continually add new lights to PGE's billing system, asset management system and tariff. This will not materially change any existing operations, just eliminate the need for additional work in the future. Additionally, there is no impact to Schedule 91 as these are old lighting technologies and are no longer being deployed in the field.

August 23, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 382
Dated August 9, 2021

Request:

Referring to PGE/500, Bekkedahl-McFarlane/20, lines 13-21,

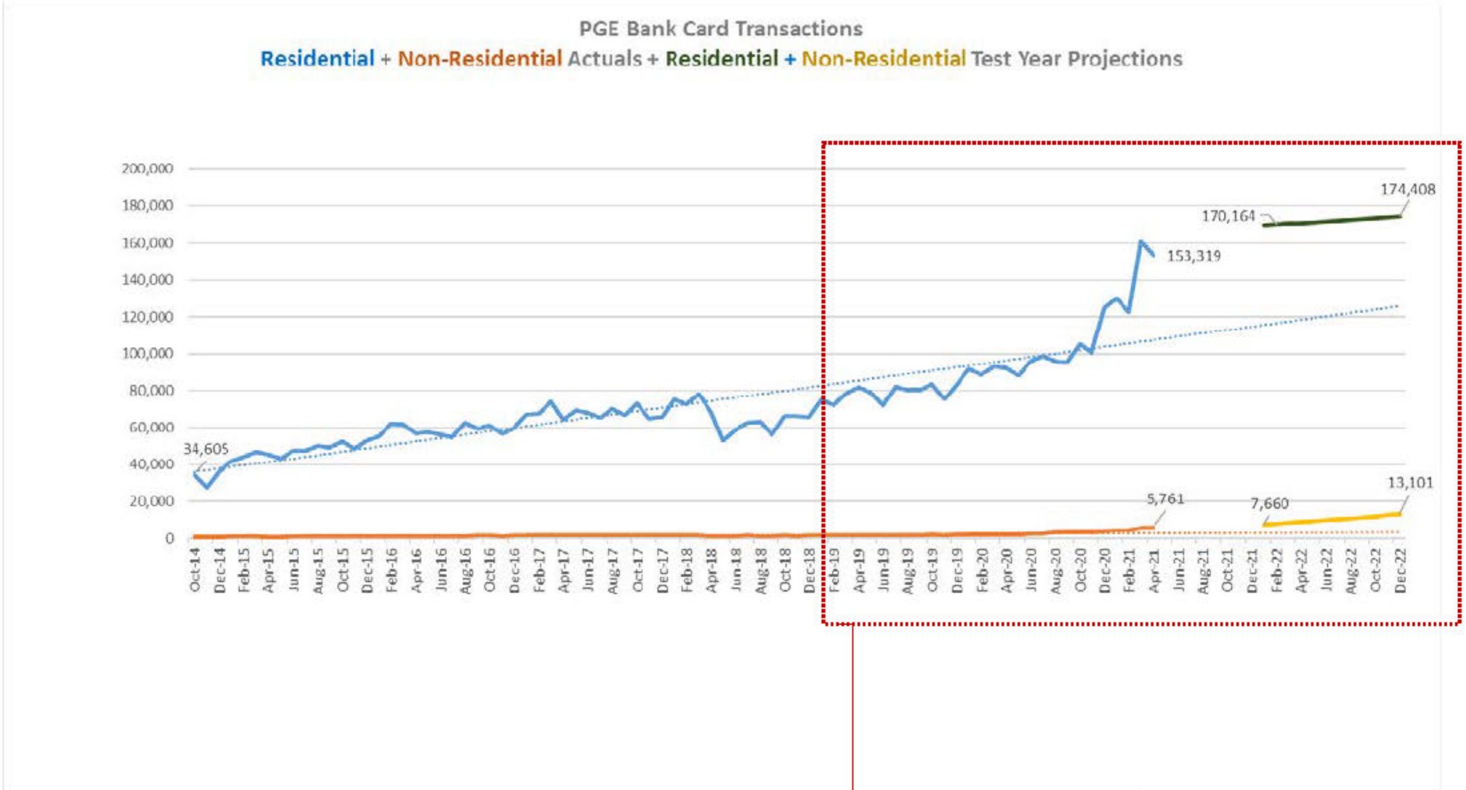
a. Please provide a detailed breakout of the incremental costs associated with:
   i. Increased adoption of the residential program ($0.5 million).
   ii. Expanding the program to commercial customers ($1.1 million).
b. Please provide the data, including associated reports and work papers, PGE used to forecast the user adoption rates for residential and commercial customers.

Response:

a. PGE misstated the total increase associated with each, residential and commercial programs. The increased adoption rate for residential programs is $0.4 million and expansion of the commercial program has incremental costs of $1.3 million. Please see PGE's response to OPUC Data Request No. 381 for the breakdown of commercial costs.

FFBC Costs (in thousands)			
	2020	**2022**	**Delta**
Residential	$1,856	$2,209	$354
Commercial	$168	$1,474	$1,306
Total	**$2,024**	**$3,683**	**$1,659**

b. Residential card fee increases are forecasted using PGE's historical trends. Please see Attachment 158-A for the adoption rates. Commercial card fees increase using PGE's historical trends from the 2014 rollout of residential card payments. Additionally, PGE's goal adoption rate of 15% for commercial customers was based on NW Natural's experience. PGE and NW Natural have many of the same customers.


PGE Bank Card Transactions
Residential + Non-Residential Actuals + Residential + Non-Residential Test Year Projections
200,000
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
34,605
153,319
170,164
174,408
5,761
7,660
13,101
Oct-14
Dec-14
Feb-15
Apr-15
Jun-15
Aug-15
Oct-15
Dec-15
Feb-16
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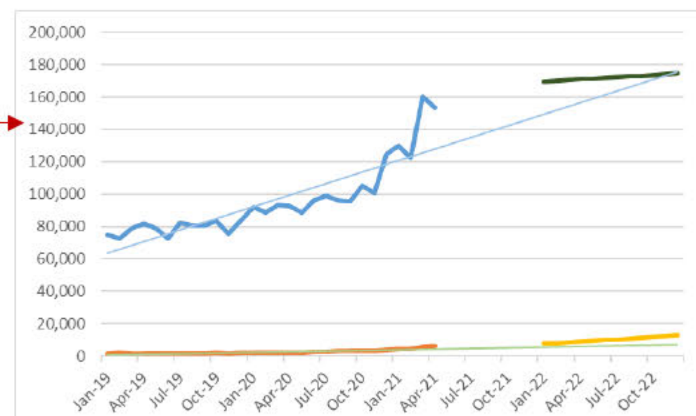
Aug-22
Oct-22
Dec-22


200,000
180,000
160,000
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
Jan-19
Apr-19
Jul-19
Oct-19
Jan-20
Apr-20
Jul-20
Oct-20
Jan-21
Apr-21
Jul-21
Oct-21
Jan-22
Apr-22
Jul-22
Oct-22

August 23, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 381
Dated August 9, 2021

Request:

Referring to PGE/500, Bekkedahl-McFarlane/19, lines 7-12,

a. For each month of the test year, please provide the projected number of small commercial fee free and other commercial customer users and costs of the proposed small commercial program.

b. Besides Schedule 32, what other commercial customers and respective schedules is PGE proposing to have available a fee-free bank card payment offering. If none, please explain why.

c. What tariff or rule language covers this option and where is it located in PGE's filing?

Response:

a. Please see attachment 381-A for the forecast of non-residential fee free bank card users. Please note, this forecast was developed in 2020 and PGE is already seeing higher adoption rates and fees than originally projected.

b. Per the negotiated contract with Visa payment processor, PGE must treat all commercial customers under a single payment fee structure. As a result, fees are not specific to commercial customer schedules (all commercial rates charged the same fee), instead PGE has a limit on card payments applicable to all schedules. The limit for a single fee free card transaction for any customer type is $5,000 per PGE account.

c. Please see PGE's response to OPUC Data Request No. 380, part a, for further details on the authority to offer this option.

August 23, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 380
Dated August 9, 2021

Request:

Referring to PGE/500, Bekkedahl-McFarlane/18, beginning at line 13, and with reference to footnote 13 on that page:

a. What agreement with Staff or approval from the Commission was obtained to expand the fee free program beyond the residential class of customers or does PGE believe notifying OPUC staff is sufficient?
b. Please provide a narrative explaining part "a" above in greater detail.
c. Once PGE decided to offer the fee free payment options to all other non-residential customers, did PGE decline to any customer the option to pay by credit card? If yes, please explain.
d. In what accounts did PGE record the costs of offering this option, and are the costs included in any deferral account?
e. Please provide a breakout of the costs associated with this offering, including type and dollar amount.

Response:

a. Commission Order No. 15-356 states "The parties agree that PGE would not launch a commercial FFBC program in 2016 and would notify Staff no less than forty-five days before launching a commercial FFBC program." In accordance with this order, PGE notified Staff of the inception of the FFBC program for commercial customers at the end of March 2020.
b. Due to the urgency of the recession caused by COVID-19, PGE could not give advance notice of the program. However, because the program was initiated between general rate case proceedings, the costs of the program were born by the shareholders, not ratepayers.
c. PGE established dollar limits on program participation and did not decline any customer this option if their bill was within the established limits.
d. PGE records the expenses related to all Fee Free Bank Cards in Account 9030001: CustAcct-CustRecords&Collect. None of the program expenses were included in any deferred accounts.
e. Please see PGE's response to OPUC Data Request no. 158, Attachment 158-A for monthly costs associated with non-residential customers.

August 23, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 376
Dated August 9, 2021

Request:

Referring to PGE/500, Bekkedahl-McFarlane/17:

a. Beginning at line 17, for each year since the inception of the fee free bank card program, how were the costs of the program allocated across customer classes?

b. Please explain why this is a reasonable method of cost allocation.

Response:

a. The costs of the fee free bank program are embedded in the electronic bills and payments resource center. The combined costs are allocated across all customers based on the percentage of customers enrolled in paperless billing. PGE has applied this methodology going back to 2015 when costs for electronic bills were allocated to customers under 200 kW.

b. The program costs are weighted toward customer classes enrolled in paperless billing as they are more likely to benefit from the program. Residential and small nonresidential customers are appropriately allocated the majority of the costs with approximately 93% of the costs being allocated to Schedule 7 customers and approximately 6% being allocated to Schedule 32 customers.

August 23, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 378
Dated August 9, 2021

Request:

How is PGE proposing to recover/allocate the costs of a small business fee free bank card program across customers?

Response:

PGE proposes to allocate the costs of the commercial fee free bank program in the same manner as the existing program. See PGE's Response to OPUC Data Request No. 376.

August 23, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 373
Dated August 9, 2021

Request:

Please provide the most current data capturing significant and uncommon attributes for residential customers utilizing the fee free bank card program in the same or similar format as submitted in the PGE Fee Free Bank Card (FFBC) Program Report, 2015 shown here:

Significant Attributes of Fee-Free Bank Card Use

Profile is for data of FFBC users as of Fdecember 31, 2014

Attribute	Profile %[1]	Reference %[2]
Renter	71%	43%
Education (Acxiom[3]): High School-VoTech	62%	51%
15-Day Notice(s) Past 12 Mo. (CIS)[4]	35%	24%
PGE Segment (Acxiom): Continually Connected[5]	49%	14%
Account Years: Under two years	47%	26%
PGE Credit: Not Excellent (CIS)	27%	15%
5-Day Notice(s) Past 12 Mo. (CIS)	25%	14%
Low-Income (Acxiom): Under $40,000	38%	26%
Occupation (Acxiom): Blue Collar	21%	14%
Time-Payment Agreement (TPA)	7%	2%
Agency Assistance Past 12 Mo. (CIS)	4%	3%

Uncommon Attributes of Free-Free Bank Card Users

Attribute	Profile %	Reference %
Affordability Level (Acxiom): High	30%	53%
Education (Acxiom): College	29%	34%
High-Income (Acxiom): $75,000 plus	30%	42%
Homeowner	29%	57%
Account Years (CIS): 6+ years	27%	52%
Education (Acxiom): Graduate School	9%	15%

Response:

Attachment 373-A provides the requested information, from which a low-income determination can be made. Axiom data in this response uses methodology similar to the 2014 example provided by Staff. Axiom is a third-party contractor, and their data does not provide full income data for individual customers, as a result other observable data was used to identify lower income as referenced in PGE's response to OPUC Data Request 371.

“PGE Response to OPUC DR 373 Attachment A”

is filed in electronic format

October 5, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 852
Dated September 21, 2021

Request:

Referring to PGE's response to OPUC DR 381(b), please:

a. Provide the date(s) that PGE executed or otherwise agreed to terms with a payment processer company relating to commercial customers fee free card payments.
   i. How do the date(s) provided in subpart (a) of this DR compare to the date PGE notified Staff PGE would begin offering the fee free option to commercial customers?
   ii. Include as an attachment: the contract with the Visa payment processor.
b. Describe how PGE solicited or connected with the Visa payment processor;
c. Explain why the terms of the contract require PGE to treat all commercial customer schedules under a single payment fee structure;
d. Specify what the per transaction fee (including any flat fees and percentage of bill amounts) is, and where it 12 is detailed in the contract provided to subpart (a) of this DR;
e. Please explain how commercial customers are defined; and
f. Please explain why or why not industrial customers are included in the answer to subpart (e) of this DR.

Response:

a. PGE had a phone call with the Energy Rates, Finance and Audits Administrator in March 2020 to notify OPUC of the offering to non-residential customers. Because the notification was via a telephone call, PGE does not have a record of the specific date of the call. PGE began offering fee free card payments to non-residential customers on April 7, 2021.

   Please see highly confidential attachment 852-A for the executed payment contract and contract modifications.

b. PGE engaged in the RFP process as established by PGE internal policy. Please see Confidential Attachments 852-B and 852-C for more information.

c. Visa® Merchant Operating Rules do not permit “tiered pricing” when a consumer is paying any portion of the ‘Convenience Fee.’ It must be a fixed or flat fee regardless of payment amount. Given this operating rule, we cannot offer a “tiered” price to some commercial customers but not all commercial customers.

d. Please see PGE’s response to OPUC Data Request No. 375.

e. The definition of a commercial customer can be found in ORS 757.602(2) and OAR 860-038-0005. For the purposes of this program, the participants are differentiated by residential and non-residential accounts only.

f. Please see part e. above.

Attachment 852-A contains confidential information and is subject to Modified Protective Order 21-237.

Attachment 852-B and 852-C contains protected information and is subject to General Protective Order No. 21-206.

CASE: UE 394
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

REDACTED

Confidential Exhibits in Support of Opening Testimony

Protected Information Subject to General Protective Order No. 21-206

October 25, 2021

REDACTED

"PGE Response to OPUC DR 414"

This Exhibit is Confidential and Subject to General Protective Order No. 21-206

CASE: UE 394
WITNESS: MICHELLE SCALA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 404

REDACTED
Highly Confidential Exhibits in Support of Opening Testimony

Protected Information Subject to Modified General Protective Order No. 21-237

October 25, 2021

REDACTED

"PGE Response OPUC DR 849"

This Exhibit is Highly Confidential and Subject to Modified General Protective Order No. 21-237

REDACTED

"PGE Response OPUC DR 852-A"

This Exhibit is Highly Confidential and Subject to Modified General Protective Order No. 21-237

CASE: UE 394
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

REDACTED

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Brian Fjeldheim. I am a Senior Financial Analyst employed in the Rates, Finance and Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. I present Staff analysis in the general categories of non-labor administrative and general expenses (A&G), information technology (IT) and IT projects, physical and cyber security, working capital, employee health insurance, other insurance, amortization expense, the Colstrip decommissioning date, and the Trojan Nuclear Decommissioning Trust.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. A&G EXPENSES (NON-LABOR)

Q. Please summarize Staff's adjustment for A&G expense.

A. Staff recommends three separate adjustments to 2020 non-labor A&G expenses totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Staff finds that the Company has failed to fully provide the required minimum level of detail necessary to establish the business necessity and prudence of the expenditures in question and has failed to exclude discrete labor expenditure data from their responses to SDR 057 and 058(b).[1] After engaging with the Company multiple times via email, phone, and Microsoft Teams, the Company submitted three subsequent revisions to SDR 058,[2] as well as a single revision to SDR 057.[3]

Despite the efforts from Staff to obtain from the Company the minimum level of detail required, there remain 760 individual line entries in SDR 057 for 2020 A&G expenditure data with no transaction description, vendor

[1] The instructions for SDR 057 read as follows: "Please provide transaction summaries for Non-Labor costs recorded in all FERC Accounts for the Base Year. Please place in MS Excel and for each transaction include: a. Total amount charged, and as applicable, any subtotals assigned to Non-Utility/Total Company Allocation and/or OR-Allocation; b. Description of cost; c. Name of vendor (if applicable); d. Business Unit (Profit Center) being charged; e. Service provided (e.g., reports to stockholders, lease, etc.)."
The instructions for SDR 058(b) read as follows: "Please provide a separate table in Excel for each subpart:

a. For all FERC Accounts, please provide all of the information in the format as shown in Attachment 58 A or B2. If the requested information is not relevant to the Company's operations, please enter "N/A" in the appropriate cell.
b. Please provide the same information requested in a. above except EXCLUDE Labor Expense, from all entries." (Emphasis added)[2] Staff/502, Fjeldheim/1-4. PGE revised responses to Staff SDR 058.

[2] Staff/502, Fjeldheim/1-4. PGE revised responses to Staff SDR 058.
[3] Staff/503, Fjeldheim/2-3. PGE revised response to Staff SDR 057.

information, or any specific means of determining the nature of the expenditures in question. There are also more than 7,400 entries for 2020 A&G expenditure data labeled **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and 12 entries for 2020 A&G expenditure data labeled **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** that are labor or labor loading related.[4] Staff cross referenced PGE's confidential SDR 057 response to the revised SDR 058 responses and confirmed these entries are also present in the SDR 058 non-labor A&G totals for 2020. Staff recommends all identified A&G expenditure dollar amounts be adjusted out of the 2020 Base Year and disallowed for the 2022 Test Year.[5]

Q. What are A&G expenses?

A. Administrative and general (A&G) expenses include human resources, accounting and finance, insurance, contract services and purchasing, corporate security, regulatory affairs, legal services, and information technology (IT), research and development (R&D), employee benefits and incentives, support services, and regulatory fees that fall within the Federal Energy Regulatory Commission's (FERC) definition of A&G.[6]

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[4] Staff/503, Fjeldheim/3, PGE's confidential response to Staff SDR 057 – Attachment B. Excel file "UE 394_OPUC DR 057_Attach B_CONF_", worksheet "Transaction Data", Excel column N, submitted on August 27, 2021 via Huddle.

[5] Staff/503, Fjeldheim/4-6, PGE's confidential response to Staff SDR 057 – Attachment B. Excel file "UE 394_OPUC DR 057_Attach B_CONF_", worksheet "Transaction Data" with Staff data filters.

[6] Code of Federal Regulations (CFR), title 18, Chapter I, Subchapter C, Part 101 - Uniform System of Accounts (USOA) Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Accounts 920 – 935. Available at: https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101.

Regarding non-labor A&G expenses, several members of Staff performed individual analysis on various subcomponents of A&G. In my testimony, I address the following A&G subcomponents: office supplies and expenses (FERC 921), administrative expenses transferred – credit (FERC 922), outside services employed (FERC 923), duplicate charges – credit (FERC 929), miscellaneous general expenses (FERC 930.2), rents (FERC 931), and maintenance of general plant (FERC 935). I also review a few categories of labor A&G in subsequent sections of my testimony.

Expenses for customer service, customer assistance, management deferred compensation plan, supplemental executive retirement plan, corporate image advertising, memberships, dues, cash contributions and donations, research and development (R&D), and directors and officers (D&O) insurance are addressed by other members of Staff in opening testimony.[7]

Q. Please summarize the Company's overall request for A&G expense.

A. In the Company's filing, PGE reports actual A&G expenditures of $193.0 million in 2020, budgeted expenditures of $205.6 million in 2021, and a forecasted 2022 Test Year amount of $186.9 million.[8] According to PGE, the primary drivers of the $6.1 million decline in Test Year A&G expenses (from 2020 actuals to the 2022 Test Year) are:[9]

7 Staff/300, Cohen – addresses all manner of wages, salaries, and compensation accounts; Staff/400, Scala – addresses customer service accounts; Staff/600, Dloughy – addresses pensions and post retirement health accounts; Staff/1100, Moore – addresses D&O accounts; and Staff/1600, Kim – addresses R&D accounts.

8 PGE/401, Ajello-Batzler/1.

9 PGE/400, Ajello- Batzler/6 at Table 1 and PGE/401, Ajello-Batzler/1.

- Elimination of severance expenses ($0.0 in 2022 compared to $8.4 million in 2020);
- Reduced incentives expense by $15.4 million ($13.7 million in 2022 compared to $29.9 million in 2020);
- Increased insurance expense of $5.4 million ($17.9 million in 2022 compared to $12.6 million in 2020);
- Increased benefits costs of $7.2 million ($59.6 million in 2022 compared to $52.3 million in 2020);
- Corporate cost reduction of $4.4 million ($0 in 2020).

Q. Does Staff analyze A&G expense in the same way as the Company?[10]

A. No. The Company does not separate labor from non-labor to forecast its A&G expense. The Company uses a combination of labor and non-labor expenses to derive their Base Year and Test Year A&G expenses and rolls these costs into Company specific cost centers.[11]

In contrast, Staff analyzes the labor and non-labor components of A&G separately and by FERC account rather than the Company-created "cost centers." Labor expenses receive specific Staff review and analysis are addressed by Staff witness Heather Cohen in Staff/300. Additionally, certain labor loading expenses (i.e. pension and retirement benefits, payroll taxes, incentive pay, etc.) are analyzed separately by various Staff.

10 A&G dollar amounts provided in PGE/200, Tooman – Batzler/6 at Table 1; PGE/400, Ajello-Batzler/2 at Table 1; and PGE/401, Ajello-Batzler/1 include components of labor and/or labor loading expenses, such as benefits, incentives, and paid time off (PTO).

11 *Id.*

To determine the reasonableness of the Company's Test Year forecast for non-labor A&G, Staff often relies on its analysis of actual A&G expense in previous years and compares Base Year actuals to the Company's forecasted Test Year expense. To do this, Staff reviews PGE's expenses by FERC account. OAR 860-027-0045 specifies that PGE must adhere to the Uniform System of Accounts (USOA) adopted by FERC for accounting. Under USOA, expense for A&G is recorded in FERC accounts 920-935.

To facilitate its review of the labor and non-labor components of A&G, Staff created Standard Data Requests (SDRs) that each utility must answer at the time it files a general rate case (GRC). SDR 057 requires the Company to provide all of its actual non-labor expenses and revenues, by FERC account, for the Base Year. SDR 058 requires the Company to provide forecasted summaries of expense for the Test Year, by FERC account. SDR 058 also requires the Company to provide all expenses and revenues, by FERC account, for the Base Year and the preceding two years. SDR 057 instructs that only non-labor expenses be reported, and SDR 058 instructs utilities to separately report labor and non-labor expenses.

Q. How did Staff review PGE's non-labor A&G costs at issue in testimony?

A. Staff relied on PGE's actual expenses recorded in the FERC accounts to review year-to-year changes in non-labor expenditures for major functional areas by FERC account. Staff also relied upon the Company's responses to SDR 057 to verify SDR 058 Base Year non-labor dollar figures for 2020 and to investigate expense recorded in A&G accounts by line item cost detail information using individual cost elements (CE).

This review process was not simple. The Company submitted three revisions to SDR 058 after its initial filing as well as a single revision to SDR 057. The revised filings were generally prompted by Staff inquiries by phone, e-mail, and Microsoft Teams attempting to understand discrepancies or lack of specified information in the SDR responses. Notwithstanding the revisions at Staff's prompting, the revised SDR 057 response still contains **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** individual A&G transaction line items with blank entries for expenditure "line description"[12] and "vendor"[13] totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. PGE's 2022 Test Year is based on its forecasted costs. Why is it relevant that PGE's FERC accounts for actual A&G expense in 2020 include unidentified expense?

A. Staff compared PGE's forecasted expense for the same FERC accounts for 2021 and 2022. PGE's forecasted expense is consistent with its historic actual expense. Meaning it appears that the expense PGE is planning for in 2022 is the same type of expense it incurred in 2020. Accordingly, Staff is unable to ascertain the reasonableness of unidentified expense.

Q. Did you find other expenses in PGE's historic actual non-labor expense that is not appropriate for recovery in the Test Year?

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12 Staff/503, Fjeldheim/4. PGE Excel file "UE 394_OPUC DR 057_Attach B_CONF_", worksheet "Transaction Data", Excel column N = "blank".

13 *Id.*, Excel column Q = "blank".

A. Yes, Staff found that PGE recorded labor expense as non-labor expense in the data provided in its responses to both SDR 057 and 058. Recovery for labor expense is addressed separately and presumably included in other components of PGE's revenue requirement reviewed by Staff witness Cohen. Labor expense should not be recovered as non-labor A&G, or else it is likely it would be double recovered. Despite the Company's assistance with identifying and filtering specific cost elements (CE)[14] associated with labor and labor loading expenses from PGE's revised SDR 057 response, Staff identified additional transactions with labor descriptions, either in Excel column I titled "Cost Elm Description" or Excel column N titled "Line Description". Using a description of "gross earnings" as a filter criteria in Excel column N, Staff identified just over **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** transactions that are labor related, totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[15] Staff further identified 12 transactions using a description of "LL-Postretirement Service Cost" as a filter criteria in Excel column N that are labor related, totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[16]

Q. How did Staff exclude labor expenses from SDR 057 data?

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[14] Per phone conversations and email correspondence with PGE representatives, CE series 13XX = paid time off (PTO); CE 2903 = payroll taxes; and 51XX = labor loading and overheads. All of these CEs were filtered out as part of Staff's analysis.

[15] Staff/503, Fjeldheim/5. PGE Excel file "UE 394_OPUC DR 057_Attach B_CONF_", worksheet "Transaction Data", Excel column N = [redacted].

[16] Staff/503, Fjeldheim/6. PGE Excel file "UE 394_OPUC DR 057_Attach B_CONF_", worksheet "Transaction Data", Excel column N = [redacted].

A. Staff started with the 2020 actuals included in PGE's response to SDR 057. Staff then used data filters to exclude labor and labor-related loading expenses from the expenditure details to build an accurate non-labor expense data set for the 2020 Base Year.

Staff excluded the following CEs: 13XX – Paid time off and vacation holiday account (VHA) and earned time off (ETO); 2903 – payroll taxes; and 51XX series – which includes expenses such as pension service cost, incentive overhead, allocated payroll taxes, etc.[17] Overall, Staff excluded employee benefits (net of capital allocations) of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, incentives of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, and paid time off (PTO) of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. All of these are labor or labor loading expenses.

[17] Staff/502, Fjeldheim/9-10. PGE response to SDR 078, PGE Attach A. Note: PGE made a small typographical error in their response title to SDR 078. The Company refers to SDR 070 instead of SDR 078. The narrative content and associated Attachment A respond to SDR 078.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. What adjustment did Staff make based on this analysis?

A. Staff excluded these expenses because they are labor expenditures and should have been excluded from the Company's responses to SDRs 057 and 058(b), which should only include non-labor expenditure data.

Q. How does Staff know the labor expenses excluded by Staff's adjustment are included in PGE's forecasted Test Year expense?

A. PGE's 2022 Test Year forecast for the FERC accounts at issue is consistent with the 2020 historic actuals *before* Staff's adjustments to remove the labor expense and unidentified expense. Unless PGE replaced these unidentified and labor expenses recorded in 2020 with other expenses of relatively equal value, the labor expenses remain in PGE's A&G projections for 2022.

Q. Please summarize Staff's adjustments to the Test Year forecast for non-labor A&G expense?

A. Staff proposes three separate A&G adjustments.

Adjustment #1. Remove **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of unidentified expense.

Adjustment #2. Remove **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of "gross salary", which is a labor related expense.

Adjustment #3. Remove **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of "LL-Postretirement Service Cost," which is also a labor expense.

ISSUE 2. INFORMATION TECHNOLOGY (IT)

Q. Please summarize Staff's adjustments for IT projects.

A. Staff proposes three separate adjustments for IT related rate base totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

Adjustment #1. Reduce the 2020 desktop/laptop computer replacement project by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to reflect a three-year annual average for 2018, 2019, and 2021 expenditures. On average, PGE spent approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per employee for computer hardware and accessory replacement.[18] [19]

Adjustment #2. Dis-allow PGE customer mobile app expenditures of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. PGE is building and migrating to a new, mobile enabled Company website. The customer app projects appear duplicative in light of the mobile enabled functionality of PGE's customer facing website.

Adjustment #3. Reduce the Physical Access Control System (PACS) by $3.02 million, resulting in an average price of $10,000 per door/access point versus **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per door/access point.

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[18] Staff/503, Fjeldheim/9-10. PGE response to Staff DR 461, Confidential Attachment A.
[19] Staff/503, Fjeldheim/14-16. PGE response to Staff Confidential DR 791, Confidential Attachment A.

At this time, the Company has not yet fully responded to Confidential Staff DR 790. Due to the Company's pending response, Staff reserves the right to further investigate the IT projects listed in DR 790 and may make future adjustment(s) to any of the IT projects listed therein.

Q. Please summarize PGE's "IT Projects" included in this rate filing and what they do.

A. In PGE's response to Staff data DR 461, the Company identified **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** individual IT projects with costs exceeding $250 thousand. These projects consist of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, for a combined total IT capital project addition of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Out of these projects, Staff identified four groups of projects totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** that prompted additional analysis and investigation:

Group 1. This group includes the desktop/laptop life cycle replacement expenditures for the past four years totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[20] These expenditures result from replacement of employee desktop computers **[BEGIN**

[20] Staff/503, Fjeldheim/9-10. PGE response to Staff DR 461, Confidential Attachment A. PGE projects **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** and laptop/tablet computers **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** as well as associated computer accessories (monitors, keyboards/mice, headsets, etc.). The Company's median cost for replacement computers (and associated peripherals) is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per desktop computer and **[BEGIN CONFIDENTIAL]** [redacted] **END CONFIDENTIAL]** per laptop/tablet computer. Based on PGE's response to confidential Staff DR 791, the Company is spending approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per employee for computing devices and computer related expenses, with the exception of 2020. In 2020, the Company's desktop/laptop expenses nearly doubled compared to 2019 actuals and the amount budgeted for 2021.[21]

Group 2. This group includes the mobile app projects developed and deployed for PGE's customer mobile application, which allows customers to **[BEGIN CONFIDENTIAL]** [redacted]

[21] Staff/503, Fjeldheim/14-16. PGE response to Staff Confidential DR 791, Confidential Attachment A.

[redacted] **[END CONFIDENTIAL]**[22] The Company spent **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to develop, deploy, and enhance the customer app. In light of the Company's development and deployment of a new, mobile enabled website, the costs associated with these projects appear to be duplicative and unnecessary.

Group 3. This group includes the buildout out of PGE's new website, migration from the old website to the new platform, and coordination with other IT projects, including the Mobile Web project. The new website **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[23]

Group 4. This group includes the PACS project, which is a "Replacement of PGE's outdated and unsupported physical access control system (AMAG). The new **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[24] Per PGE's response to Confidential Staff DR 792, the PACS project upgrades **[BEGIN**

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22 Staff/503, Fjeldheim/9-10. PGE confidential response to Staff DR 461, Confidential Attachment A. PGE projects **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
23 *Id.*, projects **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
24 *Id.*, project **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**.

Q. How did Staff review and analyze the Group 1 – 4 IT Projects?

A. Staff reviewed Mr. Ajello's and Mr. Batzler's testimony, noting in particular their statements that the Company is "continuing to be increasingly reliant on evolving technology. This increases our need for more resilient, secure, and reliable systems with which to conduct operations and provide customer service." [25] However, most of the testimony provided deals with operations and maintenance (O&M) costs and not the underlying IT projects. Staff issued a series of data requests to gain a better understanding of the functionality and underlying business need for these IT projects, why they are needed now, and what steps the Company took to achieve least cost/least risk solutions.[26]

Q. Please discuss Staff's analysis of the desktop/laptop replacement projects (Group 1).

A. Staff reviewed four years of summary expenditure data pertaining to desktop/laptop replacement expenses and observed that 2020 desktop/laptop expenditures effectively doubled compared to 2018 and 2021. Staff also requested the Company provide a description and the price point for a "median" desktop and laptop configuration. Staff then compared these median

[25] PGE/400, Ajello-Batzler/pages 24-28.
[26] Staff/503, Fjeldheim/14-24. PGE responses to Confidential Staff DRs 789 and 791-792.

systems against other commonly available systems with similar performance/features.[27]

<u>Figure 1</u> **[BEGIN CONFIDENTIAL]**

[redacted]

[END CONFIDENTIAL].

Because the 2020 expenditures are significantly higher than the other three years reviewed, Staff proposes to reduce the permissible 2020 expense using a three-year average for 2018, 2019, and 2021 of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Why does Staff believe its proposed Test Year expense is more reasonable than the amount proposed by the Company.

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27 Staff/503, Fjeldheim/14-16. PGE response to Confidential Staff DR 791, Confidential Attachment A. Staff also used pricing for Dell desktop systems available from CDW accessed here: https://www.cdw.com/search/computers/desktops/mini-pcs/?w=CA2&ln=0&b=DLE&filter=af_processor_type_ca2_ss:(%22Core+i5%22)&maxrecords=72 The laptop configuration in use by PGE appears to be no longer offered by Dell or CDW, but Staff was able to identify a product review conducted by pcworld.com, including a 2019 price point, accessed here: https://www.pcworld.com/article/397631/dell-latitude-7400-2-in-1-review.html.

A. Based on the four year average spend for computing devices of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per employee, the Company is spending the equivalent of a midrange priced laptop or an upper end priced desktop computer every two years. This dollar amount does not comport with the Company's stated lifecycle replacement program for laptop and desktop computers.

Q. Please discuss Staff's analysis of the mobile app and new website projects (Groups 2 and 3).

A. Staff reviewed a number of online resources to determine the relative price points for corporate web apps, to include design, development, implementation, and ongoing maintenance and upgrades costs. Unfortunately, Staff identified only broad pricing metrics and generic descriptions for these types of projects. Staff also analyzed and compared the general project capabilities provided in PGE's response to Confidential Staff DR 461,[28] and it appears that most of the customer-facing capabilities of the mobile app projects are duplicated in the new website's mobile enabled features.

Staff downloaded and attempted to test PGE's mobile app on an Android cellphone and an Apple iOS cellphone. On both devices, the PGE app required an immediate user id and password and there was no app functionality without first logging in. In comparison, the Company's website appears to be mobile enabled and there was a wealth of information available

[28] Staff/503, Fjeldheim/9-10. PGE confidential response to Staff DR 461, PGE Attach A CONF, projects **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

without needing a user id or password login. Staff tested the mobile functionality of the website by turning off high-speed internet connection and using 4G and 4G LTE mobile data connections. Staff did not notice any undue system lag or web page latency that could not be explained by a 4G and 4G LTE data connection. Due to the fact that the Staff member is not a PGE customer, we were unable to further login and test customer specific features. Based on the website's main menu options, it appears that customers can: start/stop/move service; access their account, billing and online payments; report outages; contact customer support; and obtain information about various PGE programs and news. In short, the new website appears to be fully functional in a mobile environment.

Staff also researched online resources for general pricing and development metrics used in commercial app development. Unfortunately, due to the wide range of app complexity, the number of possible app features available, the options for compatibility with multiple device types, and scale of app functionality that can be designed, Staff was unable to identify specific cost or feature metrics with regard to how much a mobile app should cost compared to its feature content.

Based on the customer service features available and the relative speed with which the Company's website can be accessed using a mobile connection, it appears the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** devoted to the mobile app development is duplicative and should be removed from the rate case.

Q. Please discuss Staff's analysis of the PACS project (Group 4).

A. Staff researched access control systems online to learn how these systems work, the basic parameters of an access control system, product types and offerings, and the general development process for a large company corporate access system.[29, 30] Based on this research, it appears there is a range of remote access security systems available, from single door installations with simple numeric key pad or electronic key card access to multi-site high security systems using biometric and multi factor authentication entry access devices. For most corporate level access systems, it appears that installation and equipment costs, along with any first year software license expenses, ranges from $1,500 to $10,000 per door, depending on the sophistication of the security features at each access point, and whether the primary electronic control system uses a physical server on premises or a third party remote cloud solution.

Per PGE's response to Confidential Staff DRs 461 and 792, the PACS project will secure **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Based on Staff's research, the most expensive door systems use biometric scanners, electronic locking systems,

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[29] "How Much Does Access Control Cost Per Door?" Acme Locksmith Security Blog accessed here: https://www.acmelocksmith.com/blog/how-much-does-access-control-cost/ and Staff 502/Fjeldheim/11-19.

[30] "How Much Do Access Control Systems Cost?" Vizpin Access Control Pricing blog accessed here: https://vizpin.com/blog/access-control-pricing/ and Staff 502/Fjeldheim/20-22.

dedicated software integration, and system installation at a per door price ranging from $2,500 - $10,000.[31]

Staff would like to note that one of the drivers on the upper end door pricing involves the degree to which electrical cabling needs to be installed between the door site and the primary control system. Installation costs tend to be more expensive when access controls systems are a retrofit to doors without a previous system installed or when installed after building construction is complete. Due to the fact that PGE's integrated operations center (IOC) is new construction, it is Staff's position that the door costs should be significantly lower than retrofitting doors at the already-constructed World Trade Center offices or other existing PGE offices and locations.

Based on the apparent premium paid per door/access point, Staff recommends that the PACS project be adjusted by $3.02 million, which would drop the per door price from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Is Staff proposing any adjustments for IT projects?

A. Yes. Staff recommends three separate adjustments to IT project rate base totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**

Adjustment #1. Reduce the 2020 desktop/laptop computer replacement project by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to reflect a three year annual average for 2018, 2019, and 2021 expenditures;

31 *Id.*

Adjustment #2. Dis-allow PGE customer mobile app expenditures of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. PGE is building and migrating to a new, mobile enabled Company website.

Adjustment #3. Reduce the Physical Access Control System (PACS) by $3.02 million, resulting in an average price of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per door/access point.

ISSUE 3. SECURITY (PHYSICAL AND CYBER)

Q. Please summarize Staff's adjustments for physical and cyber security projects.

A. Staff does not recommend an adjustment for costs related to either physical or cyber security at this time.

Q. Please summarize PGE's security expenditures in this rate filing.

A. Regarding PGE's physical security expenditures, physical door/access point control expenditures are addressed in the preceding IT issue testimony. Regarding cyber security, a portion of the Company's cybersecurity investments appear to be included in PGE's construction of the new IOC. PGE testifies that its "IOC will better allow us to bring together grid control, and cyber, physical, and network security into one center."[32] The Company provides an overview of its business continuity and emergency management (BCEM) projections for increased costs in the Test Year.[33] PGE's testimony reflects the security component of BCEM is projected to increase $300,000, or 10.5 percent, from 2020 to the 2022 Test Year. The Company notes:

> The primary driver behind increasing security costs in 2022 is the additional labor needs to staff our Integrated Security Operations Center (ISOC). We are developing a more centralized capability as we move into the Integrated Operations Center (1 IOC) and taking on additional monitoring responsibility across the system. Specifically, we are expanding our coverage in the ISOC to have 24/7 on-site monitoring and response capability. Further, PGE's World 4 Trade Center (WTC) downtown offices have experienced a trend of increasing encounters with individuals engaged in civil

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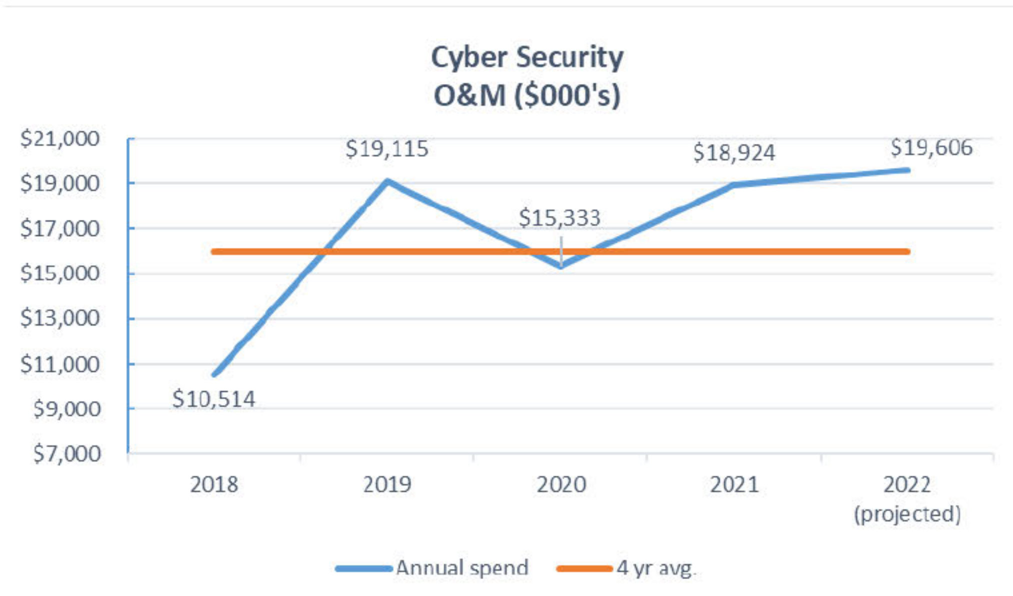
32 PGE/800, Bekkedahl – Jenkins/ at page 15.
33 PGE/400, Ajello-Batzler/ at pages 12-13, Table 4.

unrest, requiring additional investment in our security organization.[34]

The Company spends on average approximately $15.97 million on cyber security O&M (this spending is independent of capital project spending).[35] Beginning in 2019, the Company began to significantly increase cyber security operational spending.

Figure 2



Q. How did Staff review cyber security and physical security spending?

A. Staff issued a series of DRs requesting additional information on Company cyber security spending and narrative details on any data breaches or cyber intrusions in the past five years.[36] PGE responded that it has not suffered a data breach nor has it suffered any damage to its systems as a result of an

34 PGE/400, Ajello-Batzler/at pages 15-16.
35 Staff/502, Fjeldheim/26. PGE response to Staff DR 451.
36 Staff/502, Fjeldheim/23-25. PGE's responses to Staff DRs 449-450.

external cyber intrusion during this time period.[37] Additionally, the Company has not received any notification from the North American Electric Reliability Corporation (NERC) of a Critical Infrastructure Protection (CIP) violation(s) related to cyber security during this time period. The Company noted that it self-reported potential CIP violations to the Western Electricity Coordinating Counsel (WECC) during this time period.[38] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[39]

Q. Does Staff recommend an adjustment(s) for physical or cyber security projects?

A. No. Staff does not recommend an adjustment for either physical or cyber security at this time. Staff continues to review PGE's response to Staff DR 790 and may alter this recommendation in a later round of testimony.[40]

[37] Staff/503, Fjeldheim/24-26. PGE's confidential response to Staff DR 453, PGE Confidential Attachment A.
[38] *Id.*
[39] *Id.*
[40] PGE provided a voluminous response to Staff DR 790 on October 4, 2021.

ISSUE 4. CASH WORKING CAPITAL

Q. Please summarize Staff's adjustments for cash working capital (CWC).

A. Staff recommends using a historical average using the working cash factor calculated in the current filing lead/lag study and the working cash factor lead/lag calculation from the prior two rates cases.[41] This results in an adjustment of $5.565 million to rate base, and a working cash factor reduction of 0.3259 percent (Staff adjusted CWC rate of 3.8905 percent versus Company filing of 4.2164 percent)[42] for Company adjusted revenue requirement, based on adjustments from Staff and Parties Opening Testimony.

Q. Please provide a summary of the Company's filed proposal for CWC.

A. The Company provided a copy of their most recent lead/lag study, conducted for 2019. Based on this lead/lag study, the Company applied the resultant CWC factor of 4.216 percent to the projected Test Year operating expenses of $1,736.3 million. This resulted in PGE's calculated CWC Test Year need of approximately $73.2 million.[43]

Q. Please describe the components of PGE's lead/lag study and how it is used in the Company's rate case.

A. Generally, a utility provides service to customers prior to receiving payment (revenue lag). When a utility purchases goods and services, there is normally a billing delay for the payment to the vendor/seller (expense lead). Calculating

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41 See Docket Nos. UE 335 and UE 319.
42 CWC in rate base = CWC factor % x projected TY operating expenses.
43 PGE/200, Tooman – Batzler/page 24 at 13-18; PGE work paper, Excel file "Lead-Lag Working Cash Factor_2022"; and PGE/200 work paper, Excel file "Exhibit Support 2022", tab "Rev Req Base".

an appropriate level of CWC relies on two components, 1) the number of days of revenue lag and expense lead the utility experiences in a Test Year; and 2) the dollar amounts for each.

To determine lead/lag days, transactions for the year are sampled and analyzed. In the 2019 study, PGE grouped these transactions into six major groups: revenues, fuel, purchased power, labor, overhead and maintenance (O&M), and taxes.

Once the lead/lag days are determined, the annual dollar amounts for each of the six major groups are multiplied by the lead/lag days to calculate "total dollar days." The total revenue lag is calculated by dividing the total dollar days by the "annual dollars." The same relationship is also true for calculating total expense lead. The difference between the revenue days and expense days is divided by 365 days in a year to determine the lead/lag factor. This factor is then multiplied by the total projected O&M expense to estimate cash working capital needed in the Test Year.[44]

Q. Please describe Staff's analysis of the Company's proposed Test Year CWC factor.

A. Staff first compared the Company's proposed lead/lag factor of 4.216 percent against the lead/lag factor proposed in its previous five general rate cases (GRCs) as shown in Figure 3 on the following page. In the third column, Staff

[44] UE 394 PGE Work papers\UE 394 PGE Work Papers_200_Non Conf, Excel File "Lead-Lag_Working Cash Factor_2022".

notes whether the lead/lag factor proposed was the result of a new lead/lag study or based on an order from a prior docket.

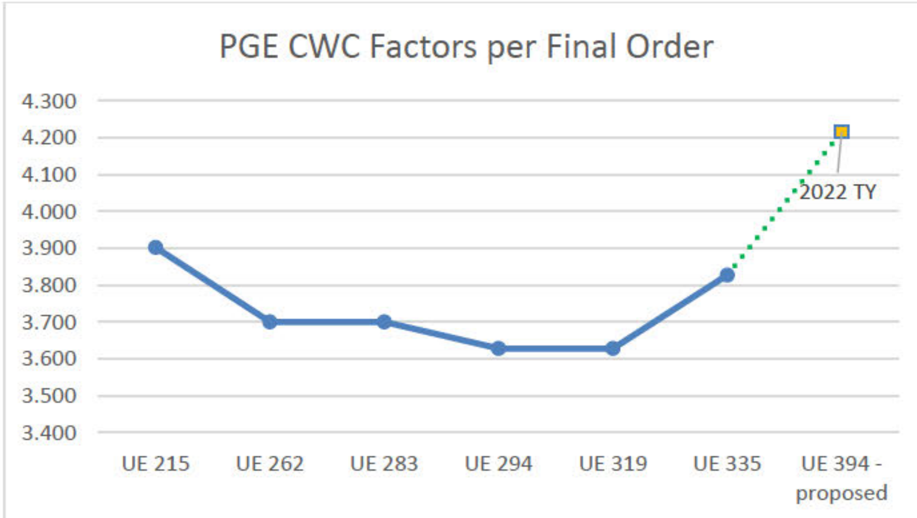
Figure 3

Docket No. (A)	Proposed PGE CWC Factor (%) (B)	New Lead/Lag Study (C)	CWC Factor - Final Order (D)
UE 262	3.980	Yes	3.700
UE 283	3.700	No. UE 262	3.700
UE 294	3.628	Yes	3.628
UE 319*	3.789	Yes	3.628*
UE 335	4.063	Yes	3.827
UE 394 - proposed	4.216	Yes	n/a
*During Docket No. UE 319, the Company completed a newer lead/lag study, which Staff incorporated into its final analysis for Docket No. UE 335.			

Q. Is PGE's proposed CWC factor of 4.216 percent reasonable?

A. In Figure 4, Staff presents PGE's proposed CWC factors as well as the CWC factors from five previous rate case filings. Compared to PGE's prior lead/lag studies, the proposed 4.216 percent CWC factor is well outside of the norm.

Figure 4



Q. Has Staff determined why the most recent lead/lag study used in UE 394 results in a working cash factor that is significantly higher than the CWC in PGE's previous GRC?

A. Yes. Staff compared the six major groups and determined between the lead/lad studies used in UE 335 and UE 394, that all six major groups saw significant changes in their relative dollar amounts and their relative dollar days The increased CWC factor for UE 394 results primarily from a 2.4 percent increase in total revenues, as compared to a 14.6 percent increase in total expenses in the study time period. In particular, labor expenses increased 31.3 percent, total O&M expenses nearly doubled, and total taxes increased 34.6 percent.

Figure 5

Lead/lag studies	UE 394 ($000's)	UE 335 ($000's)	Delta ($000's)	Delta (%)
Total Revenues	**1,778,044**	**1,732,696**	**45,349**	**2.6%**
Total Fuel	261,771	219,433	42,338	19.3%
Purchase Power	444,608	514,121	(69,513)	-13.5%
Total Labor	449,237	342,049	107,188	31.3%
Total Misc O&M	144,493	74,924	69,570	92.9%
Total Taxes	125,144	92,941	32,202	34.6%
Total Expenses	**1,425,252**	**1,243,468**	**181,784**	**14.6%**

Combining this with a slight increase in revenue lag days (1.44 days) and slight decline in expense lag days (negative 1.17), results in the PGE's proposed working cash factor of 4.216 percent.

Q. Does Staff have an explanation for the increase in the six major groups underlying the revenue/expense lag days in the Docket No. UE 394 study?

A. PGE did not provide a rationale for the increase in the six major groups. However, based on Staff's analysis described in testimony above, Staff believes that this increase is anomalous and does not represent PGE's on-going state of operations. For example, in the 2019 study, Federal taxes declined slightly, which makes sense in light of corporate tax rate reductions resulting from the Federal Tax Cuts and Jobs Act in 2019. However, it is unclear why Oregon state income taxes increased nearly fourfold beginning in 2019. One possible explanation is Oregon's corporate activity tax (CAT) was signed into law in 2019,[45] but no justification is provided by PGE regarding the

[45] 2019 Oregon House Bill (HB) 3472A, beginning on page 29, available at https://olis.oregonlegislature.gov/liz/2019R1/Downloads/MeasureDocument/HB3427/Enrolled.

increased Oregon taxation expense and whether it should be expected on a going forward basis.

Q. What is Staff's recommendation regarding the CWC rate?

A. Staff recommends using the same methodology Staff used in PGE's prior rate case and averaging the Company's prior three CWC factors calculated for each of PGE's most recent general rate cases, which were Docket Nos. UE 319, UE 335, and UE 394. This results in an average CWC factor of 3.8903 percent. Staff proposes this adjustment to the CWC factor because

- The CWC factor for the Test Year forecasts cash working capital in rate base not for a single year but for the period of time rates are in effect;
- As demonstrated, the increasing revenue lag, significant increase in operating expenses between studies, and the modest declining expense lag result in a moderate impact to the CWC factor; and
- The revenue lag days, the projected UE 394 CWC factor, and the growth in expenditures without offsetting revenue growth appear to be anomalous when compared to the prior studies

Q. What is Staff's recommendation regarding the amount of CWC to include in PGE's Test Year revenue requirement?

A. Staff's recommendation is to apply the average CWC factor of 3.8903 percent to the final O&M expenses included in the Commission final order. Based on Staff's opening testimony, Staff proposed Test Year O&M expenses are $1,736.3 million. Applying a 3.8903 percent CWC factor to

PGE's proposed O&M expenses of $1,736.3 million results in $66.416 million CWC in rate base; a reduction to the Company's Test Year CWC in rate base of ($5.568) million.

ISSUE 5. EMPLOYEE HEALTH INSURANCE

Q. Please summarize Staff's adjustments to Test Year expense for health insurance.

A. Staff proposes no adjustment for these expenses.

Q. Please summarize the Company's proposed Test Year expenses for health insurance benefits.

A. The following table illustrates the Company's medical benefit costs[46] and additional employee benefit coverages for the Base Year, the preceding two years, and the Test Year Pro Forma amounts.

Figure 6

Benefit Description	a-Dec - 2018	a-Dec - 2019	a-Dec - 2020	Dec - 2021 budgeted	Dec - 2022	$ change 2020 to 2022	% change 2020 to 2022
Benefits Administration	481,868	565,810	787,059	764,336	786,168	(890)	-0.1%
Employee Assistance Program	69,604	55,819	93,890	85,320	85,320	(8,570)	-9.1%
Employee Wellness Program	368,404	198,980	91,039	241,701	244,399	153,359	168.5%
Group Life Insurance	1,058,377	1,223,537	1,335,046	1,600,939	1,605,427	270,381	20.3%
Health & Dental Plan	47,270,077	51,765,226	47,619,945	49,871,449	53,316,637	5,696,692	12.0%
Health Reimbursement Account	3,204,489	2,383,002	2,024,970	2,323,152	2,332,272	307,302	15.2%
Long Term Disability Benefits	1,016,575	1,735,049	2,114,003	1,894,926	2,238,534	124,531	5.9%
Short Term Disability Insurance	657,288	680,004	651,090	664,400	726,800	75,710	11.6%
Total	**54,126,682**	**58,607,427**	**54,717,043**	**57,446,223**	**61,335,557**	**6,618,514**	12.1%

Q. How did Staff analyze PGE's expense?

A. In previous rate cases, Staff have used a range of historical data to perform trend analysis and determine reasonable Test Year expenditure levels. To determine the reasonableness of PGE's proposed Test Year, Staff calculated a three-year historical average for non-labor expenses with a year-over-year

46 Staff/502, Fjeldheim/5-8. PGE response to Staff SDR 063. Health and dental costs are combined in a single line item in Figure 6.

medical care inflation/escalation factor. For annual medical care inflation/escalation rates, Staff used the Kaiser Family Foundation (KFF) 2020 annual Employer Health Benefits Survey results[47] and Pricewaterhouse Cooper's (PwC) Health Research Institute (HRI) annual Medical cost trend: Behind the numbers reports for 2021 and 2022.[48] [49] In this case, the Company supplied 2020 and the two prior years of historical health benefits expenditure data. Staff reviewed the Company's data and methodologies used for this issue with no concerns noted.

Staff performed a year-to-year trend analysis of health coverage expense data provided in SDRs 063-067. In general, the current and ongoing COVID-19 pandemic likely skewed recent historical medical care costs and continues to weigh on projected 2022 medical cost growth. However, 2021 medical cost inflationary pressures were only slightly higher than in recent years, increasing 7.0 percent over 2020,[50] and the medical cost annual growth rate for 2022 is projected to decline modestly to 6.5 percent.[51] Because of COVID-19's impact on health care costs, the use of historical trends is less useful in this instance. Based on Staff research using KFF and PwC HRI data, it appears PGE's projected health care costs for the Test Year are in line with 2021 and 2022

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47 KFF 2020 Employer Health Benefits Survey available at https://www.kff.org/health-costs/report/2020-employer-health-benefits-survey/.

48 PwC HRI Medical cost trend: Behind the numbers 2021 available athttps://www.pwc.com/us/en/industries/health-industries/library/assets/hri-behind-the-numbers-2021.pdf.

49 PwC HRI Medical cost trend: Behind the numbers 2022 available at: https://www.pwc.com/us/en/industries/health-industries/library/behind-the-numbers.html.

50 *Id*. at pages 3 and 5.

51 *Id.*

medical cost growth projections. Additionally, it does not appear that 2020 medical costs were out of line with the Company's medical cost expenditures in recent years. Staff did note that in 2019, the Company **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[52]

In aggregate, the Company's projected 2022 Test Year health and dental insurance expense is $54.1 million, a $5.7 million (11.8 percent) increase over 2020 actuals, which translates to a health care cost growth rate over the two year period of approximately 5.9 percent/annually.

Q. What is Staff's recommendation?

A. Staff proposes no adjustment for this issue.

[52] Staff/503, Fjeldheim/7-8. PGE confidential response to Staff SDR 064, Confidential Attachment A.

ISSUE 6. OTHER INSURANCE

Q. Please summarize Staff's adjustment for other insurance.

A. Staff proposes no adjustment for this issue.

Q. What is included in other insurance?

A. Other insurance generally includes expenses for property and casualty, liability, workers compensation, cybersecurity, terrorism, and other insurable risk coverage.

Q. Please summarize the Company's proposed Test Year expenses for other insurance, to include property/casualty and liability premiums and uninsured loss provisions.

A. The Company provided four years of property/loss damages and injuries and damages data to derive their Test Year projections. The following table illustrates the Company's other insurance coverage premiums as well as the loss deductible by coverage type.[53]

Figure 7 - Confidential

[BEGIN CONFIDENTIAL]

[redacted]

[53] Staff/503, Fjeldheim/7-8. PGE confidential response to Staff SDR 064, Confidential Attachment A.

[END CONFIDENTIAL]

Q. What is the Commission's treatment of insurance expenses in a general rate case?

A. In previous rate cases, Staff have used a range of historical data to perform trend analysis and determine reasonable Test Year expenditure levels. In this case, the Company supplied four years of premium and retained risk data for injuries and damages, property damages, and several layers of liability coverage. Staff reviewed the Company's data used for this issue with no concerns noted.

Q. Please discuss Staff's analysis of this issue.

A. Staff performed a three year and four year trend analysis of the insurance expense data provided in SDRs 068-072. However, recent property and auto losses triggered by Hurricanes Henry and Ida are prompting significant rate hikes by major insurers across the country, which are affecting coverage premium rates in the Pacific Northwest. In my former professional experience as an insurance regulator, large flooding events resulting in water damage to hundreds of thousands vehicles often leads to a surge in insurance premiums for private and commercial auto coverage, even in geographical regions far removed from where the actual losses occurred. This trend appears to be holding up in the 2022 Test Year, with significant increases forecast for general and auto liability coverage.

In aggregate, the Company's projected other insurance expense is **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**.[54] Staff noted main all-risk property insurance premiums increased approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, while the Company's projection for general and auto liability **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Beginning in 2019, the Company **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. What is Staff's recommendation?

A. Staff proposes no adjustment for this issue.

[54] *Id.*

ISSUE 7. AMORTIZATION EXPENSE

Q. Please summarize Staff's adjustment for amortization expense.

A. Staff proposes no adjustment for this issue here.

Q. Please provide a summary of the Company's filed proposal for amortization expense.

A. The Company describes amortization as follows:

> Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life. Amortization relates to intangible assets, such as computer software and regulatory assets. As with depreciation expense, the unamortized balance of the associated assets generally appears in rate base and earns a return at the allowed rate.[55]

The Company also provided additional details of their amortization protocols in their Capital Accounting Policy provided in response to Staff SDR 080.[56] For certain intangible plant (e.g. FERC hydroelectric plant licenses), costs are amortized over the useful life of the plant. For internal use computer software, the Company normally amortizes capital costs for these assets over a period of five years. However, software assets with high dollar value and longer useful lives receive an extended amortization period up to ten years. Examples of intangible software assets included with the rate case include the 2020 Vision program, comprised of a new customer information system, meter data management system, finance and supply (FSRP) chain replacement project, and Maximo Mobile scheduling.[57]

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55 PGE/200, Tooman – Batzler/page 15, the
56 PGE Capital Accounting Policy updated December 4, 2020, pages 5, 12-13, and 17. Provided in the Company's response to Staff SDR 080.
57 PGE/200, Tooman – Batzler/page 16 at lines 1-6

Q. Why did Company amortization expense decline in the Test Year?

A. Test Year amortization declined in part due to the Company's old FSRP system, commissioned in 2011, aging out in 2021 after reaching the end of its 10 year amortization period. This produced a subsequent $4.1 million decline in software amortization expense for the Test Year.[58]

Q. How did Staff analyze amortization expense in this filing?

A. Staff primarily relied upon accounting summary data provided in the Company's response to Staff SDR 058(b). Specifically, Staff reviewed FERC account 404 - Amortization of Limited-Term Electric Plant for evidence supporting the Company's assertion that amortization expenses will decline $4.1 million in the 2022 Test Year.[59] [60] Staff noted in the many iterations of the SDR 058(b) response that beginning in 2021, the FERC account 404 expense budget declined by $1.8 million, supporting the Company's statement that amortization expense for a large intangible asset, such as the old FSRP system, did roll off in 2021.

Q. Did Staff review the Company's specific depreciation and amortization methodology in this filing?

A. No. Staff is not reviewing the Company's depreciation and amortization methodology in this rate case. Staff is reviewing these issues separately in Commission Docket No. UM 2152.

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58 Per PGE/200, Tooman – Batzler/page 16 at lines 7-12.

59 Staff/502, Fjeldheim/9-10. Per PGE response to SDR 078, the Company uses account 4040001 for software amortization.

60 PGE/204, Tooman – Batzler/page 1 at line 1.

Q. What is Staff's recommendation?

A. Staff proposes no adjustment for this issue here.

ISSUE 8. COLSTRIP DECOMMISSIONING DATE

Q. Please summarize the Company's position on the Colstrip Decommissioning Date.

A. The Company recommends moving up the Colstrip depreciation date to 2027 from 2030. This would result in an increase in annual depreciation expense of $11.3 million.[61]

Q. Is this issue addressed in any other dockets?

A. Yes. This issue is addressed in UM 2152, the Company's most recent depreciation case.

Q. What is the status of UM 2152 as of the filing of Staff's opening testimony in this docket?

A. The Company, Staff, and CUB (Stipulating Parties) have settled and filed testimony in support of the stipulation. However, AWEC objected to the stipulation, and filed opening testimony on October 1, 2021. All Stipulating Parties have filed their reply testimony, and hearings have occurred. Closing briefs are due November 10, 2021, and a Commission order is expected mid-December, 2021, prior to the due date for the second round of testimony in this case.

Q. What is Staff's position in UM 2152?

[61] Staff/502, Fjeldheim/27. PGE response to Staff DR 866.

A. In testimony in support of the stipulation, the Stipulating Parties recommend that the decommissioning date for Colstrip be moved up from the 2027 date proposed by the Company to 2025.[62]

Q. Does it appear that any other parties oppose moving the Decommissioning date up to 2025 in UM 2152?

A. No. In its opening testimony, AWEC did not appear to oppose moving the Colstrip decommissioning date up to 2025. However, AWEC recommends the Commission transfer excess theoretical reserves from other accounts to Colstrip to buy down Colstrip's undepreciated investment.[63] Stipulating Parties oppose this recommendation on the basis that the remaining life technique is the one currently used by Staff and recommended by NARUC.[64]

Q. Please summarize the overall Staff position on the Colstrip Decommissioning date.

A. Staff joined the Stipulating Parties in support of moving the Colstrip decommissioning date up to December 2025 and adjusting all depreciation costs accordingly using the remaining life technique that is the standard in depreciation cases.

Q. What is Staff's recommendation?

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[62] Staff/502, Fjeldheim/28-30. Testimony excerpt from UM 2152/Stipulating Parties/100/10-13.
[63] Staff/502, Fjeldheim/31-33. Testimony excerpt from UM 2152/AWEC/100/29-30.
[64] Staff/502, Fjeldheim/34-53. Testimony excerpt from UM 2152/Stipulating Parties/200/3-22.

A. Staff witness Peng is addressing depreciation expense in Staff/1500. Ms. Peng is waiting until the Commission issues a ruling on the UM 2152 filing to propose an adjustment to PGE's depreciation expense.

ISSUE 9. TROJAN NUCLEAR DECOMMISSIONING TRUST

Q. What is the Trojan Nuclear Decommissioning Trust (Trojan NDT)?

A. The Trojan NDT was established to provide financial assurance for the decommissioning obligations for a nuclear generating unit.[65] In particular, the Trojan NDT established and maintains a fund that is segregated from PGE's assets and outside of its administrative control to ensure that there will be sufficient funds to pay radiological decommissioning costs.

Q. What does the Trojan NDT pay for in particular?

A. The Trojan NDT pays for a variety of expenses related to radiological decommissioning. These costs include:

- Building demolition and site restoration once all the spent nuclear fuel has left the site,
- Infrastructure costs associated with transferring spent fuel to rail cars for transportation to a Department of Energy facility,
- Long-term management of spent fuel before it is transferred to a Department of Energy facility, and
- A contingency amount for any unexpected variation in future costs.

Q. What is the Company requested expense regarding the Trojan NDT?

A. The Company is requesting $1.9 million in amortization expenses for the Trojan NDT.[66] This is a slight increase over 2020 actuals but maintains the same accrual rate used in the past.[67]

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[65] Staff/502, Fjeldheim/54. Company's reply to Staff DR No. 749.
[66] PGE/200, Tooman – Batzler/15.
[67] PGE/200, Tooman – Batzler/16-17.

Q. Please summarize Staff's analysis of this issue.

A. Staff analyzed the assets included in the trust and the Company's financial assumptions about the trust. The trust contains 100 percent Fixed Income investments including Corporate bonds, Government bonds, Municipal bonds mortgage-backed securities, and cash.[68] These assets provide a predictable stream of income for the trust.

Q. What analysis did Staff perform the financial assumptions used for the Trojan NDT?

A. Staff examined the workpapers the Company included in its confidential attachment to Staff DR No. 754.[69] In calculating the amortization expense, the Company had to make assumptions on the inflation rate, treasury yields, the Federal Funds rate and mortgage rates, and many other commonly used financial indicators.

Assumptions around future financial indicators are bound to vary depending on the source and granularity of the data, the horizon over which the Company forecasts, and the data sources. Staff allowed for this when examining the Company's workpapers, and limited the examination to large outliers relative to today's markets. Staff found no notable outliers in the financial assumptions used by the Company.

Q. What is Staff's recommendation concerning amortization expense for the Trojan NDT.

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[68] Staff/502, Fjeldheim/55, PGE response to Staff DR No. 752.
[69] Staff/503, Fjeldheim/11-12. PGE confidential response to Staff DR No. 754, Confidential Attachment A.

A. Staff proposes no adjustment for the Company's Trojan NDT.

Q. Have you prepared a table showing the proposed adjustments in your testimony addressing all of the issues you have written about?

A. Yes.

[BEGIN CONFIDENTIAL]

Summary of Staff/500 Adjustments

(dollar amounts in 000's)	Company Filing	Staff	Adjustment
Issue 1 - A&G Expenses (Non-Labor) EXP	[redacted]	[redacted]	[redacted]
Issue 2 - Information Technology (IT) RB	[redacted]	[redacted]	[redacted]
Issue 3 - Security (Physical and Cyber) EXP	$ 21,506	$ 21,506	$ -
Issue 4 - Cash Working Capital (CWC) RB	$ 71,984	$ 66,419	$ (5,565)
Issue 5 - Employee Health & Life Insurance EXP	$ 54,717	$ 54,717	$ -
Issue 6 - Other Insurance EXP	[redacted]	[redacted]	[redacted]
Issue 7 - Amortization Expense EXP	$ 59,713	$ 59,713	$ -
Issue 8 - Colstrip Decommissioning Date EXP	$ 338,741	$ 338,741	$ -
Issue 9 - Trojan Nuclear Decommissioning Trust EXP	$ 1,900	$ 1,900	$ -
Subtotal	**$ 726,234**	**$ 666,483**	**$ (59,751)**

[END CONFIDENTIAL]

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Exhibits in Support
Of Opening Testimony

October 25, 2021

WITNESS QUALIFICATION STATEMENT

NAME:	Brian Fjeldheim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Science, Business Accountancy Regis University, Denver, CO Bachelor of Science, Aviation Technology Metropolitan State College of Denver, Denver, CO
EXPERIENCE:	I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since May of 2018 in the Energy, Rates and Finance Division. I currently perform a range of financial analysis duties related to natural gas and electric utilities, with a focus on rate case, operational audit, and annual Purchased Gas Adjustment (PGA) filings. I have participated in utility general rate cases and power cost filings in the following dockets: Cascade Natural Gas – UG 347, Avista Utilities – UG 366, NW Natural – UG 388, PacifiCorp – UE 374, Avista Utilities – UG 389, Cascade Natural Gas – UG 390, PacifiCorp – UE 390, and PGE – 391. I have nine years of professional level financial analysis and accounting experience. I was previously employed as a Budget and Fiscal Analyst with the Oregon Department of Justice (DOJ), where I was responsible for the budget build and ongoing budget execution of four legal divisions with 165 staff members and a biennial budget of $75 million. Prior to DOJ, I was employed as a Senior Budget Analyst with the Oregon Department of Administrative Services (DAS) and was responsible for the budget build, ongoing budget execution and cash flow analysis for the state data center with a biennial budget of $165 million. Prior to DAS, I worked as a Financial Analyst for the Insurance Division of the Department of Consumer and Business Services (DCBS), where I performed financial analysis and solvency surveillance of nine Oregon insurers with annual revenues of $1.4 billion and assets of $1.1 billion.

CASE: UE 394
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

October 25, 2021

September 28, 2021

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE *Third Revised* Response to OPUC Standard Data Request 058
Dated March 10, 2015

Request:

Please provide a separate table in Excel for each subpart:

a. For all FERC Accounts, please provide all of the information in the format as shown in Attachment 58 A or B. If the requested information is not relevant to the Company's operations, please enter "N/A" in the appropriate cell.

b. Please provide the same information requested in a. above except EXCLUDE Labor Expense, from all entries.

Response:

Initial Response (dated July 19, 2021):

PGE objects to this request on the basis that it is overly broad and unduly burdensome. Without waiving that objection, PGE responds as follows:

PGE's budget methodology uses the best information available to forecast operating financial results. This is performed through one sided entries as PGE does not forecast (budget) most balance sheet accounts. Because PGE's test year forecast is created to generate a revenue requirement, there are a number of components that will not match actual accounting for historical years:

- PGE does not budget a full balance sheet.
- Only a portion of the costs comprising a balance sheet are included in rate base for the revenue requirement.
- Not all accounts from the income statement are included in the revenue requirement.
- Certain lines on the revenue requirement represent revenue sensitive costs that are calculated rather than budgeted.
- The forecast for retail revenue is calculated by the revenue requirement but PGE performs additional modeling by rate schedule and not FERC account.

Detail for PGE's test year forecast is provided in the file Exhibit Support.xlsx in work papers to PGE Exhibit 200.[1] Ultimately, the individual forecasted amounts in Exhibit Support.xlsx sum to each line item of the revenue requirement. For historical years, PGE's Regulated Results of Operations report (ROO) provides all of PGE's regulated costs and revenue.

Attachment 058-A provides the following information:

- Column B of Tab 1 provides PGE's filed 2022 revenue requirement forecast for all income statement FERC accounts, with revenue sensitive costs and costs not forecasted in PGE's accounting system provided at the bottom.
- Columns F through J of Tab 1 provide all of PGE's income statement costs for 2017 actuals through 2022 forecast as recorded in PGE's accounting system, with FERC account, labor/non-labor, and utility/non-utility/other designations.
- Tab 2 provides trial balances for the balance sheet accounts (not included in Tab 1) along with detail pertaining specifically to rate base components.
- Tab 3 provides budgeted income statement amounts for 2020 by FERC account.

Revised Response (dated August 5, 2021):

Attachment 058-A inadvertently excluded 2020 actual data for the following FERC accounts: 409.1, 409.2, 410.1, 410.2, 411.1, 411.2, 426.5, 433, 920, and 923, and 930.2. Attachment 058-A *Revised* includes these data.

Supplemental Response (dated September 10, 2021):

Following a September 7, 2021 discussion with OPUC Staff, Attachment 058-B supplements PGE's revised response to OPUC Standard Data Request No. 058, Attachment 058-A Revised to include a separate column for actual amounts before adjusting items and a separate column for adjustment amounts, which sum to amounts previously provided. Additionally, PGE has described each adjustment by FERC account and included a new tab listing each PGE cost element and description.

Revised Response (dated September 23, 2021):

Attachment 058-A and Attachment 058-B inadvertently provided 2022 forecast data, prior to PGE finalizing the 2022 test-year revenue requirement. As such, Attachment 058-C corrects the following FERC accounts, which now align with PGE's filed revenue requirement: 407.4, 553, 571, 580, 583, 588, 592, 593, 908, 924, and 930.2. Additionally, Attachments 058-A and 058-B included amounts in column B (i.e., 2022 Filed RevReq) of tab "SDR 058 FERC 403-935" for accounts not included in PGE's filed 2022 revenue requirement. These accounts have been set to zero in Attachment 058-C. Attachment 058-C, tab "SDR 058 FERC 101-283" also revises columns D and E to reflect balances, rather than activity and recategorizes FERC Account 158.1 as Fuel Stock, consistent with PGE's Results of Operations reporting.

Revised Response (dated September 28, 2021):

Attachment 058-D revises PGE's response to OPUC Standard Data Request No. 058, Attachment 058-C to include PGE's 2022 forecast uncollectibles expense (as filed in PGE's 2022 test year revenue requirement) in FERC account 904.

PGE's Response to Staff Standard Data Request 58
Attach A-D

Is

Filed in electronic format

July 19, 2021

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Standard Data Request 063
Dated March 10, 2015

Request:

In the following table format, please provide medical benefit costs for the Test Year, Base Year, and the three years prior to the Base Year. Please also explain if the amounts reflected in the Company's response are before or after employer/employee sharing. For the Test Year estimates, please explain the assumptions relied upon (i.e. increased employees, specific escalation factor to premiums, etc.) in arriving at the forecasted amounts.

	Test Year	Base Year	Base Year - 1	Base Year - 2	Base Year - 3
Medical					
Dental					
401(k)					
Group Life Insurance					
Retiree Life Insurance					
Long-Term Disability					
Other (*Please Label*)					
Total					

Response:

Attachment 063-A provides detailed benefit costs after employer/employee sharing. Note that the categories are slightly different than requested because PGE groups benefit costs into different categories. The assumptions relied upon for test year estimates are described below.

Health & Dental:
Premiums for active union health insurance are based on a forecasted premium increase of approximately 8% for 2022. Union retiree medical expense for 2022 is based on a discount rate of 2.46% and an assumed Expected Return on Assets (EROA) of 7.0%.

Health insurance premiums for active non-union employees are based on the following rate increase forecasts for 2022 provided by Mercer:

- Kaiser Medical: 7.2%
- Kaiser Dental: 2.0%
- Providence: 7.2%
- MetLife Dental: 2.0%

Non-union retiree medical expenses for 2022 are based on a discount rate of 2.48% and an assumed EROA of 4.84%.

Employee Assistance Program:

The 2022 forecast is based on the current vendor contract(s) cost schedule.

Health Reimbursement Account (HRA):

The 2022 test year forecast assumes PGE continues to fund the union HRA trust. The union HRA forecast is based on a discount rate of 2.62% and an assumed EROA of 6.0% The non-union HRA is based on a discount rate of 2.53% and an assumed EROA of 2.25%.

Short-Term Disability:

Assumes 2022 union wages increase 3.5% and STD premiums increase 5%. Non-union short-term disability costs are included in wage and salary costs.

Long-Term Disability (LTD):

Forecasts of LTD medical costs assume a discount rate of 2.12%, number of current participants, demographics of the population, and projections of usage based on history. The forecast also includes LTD insurance for the union population which assumes a 3.5% wage increase and a premium increase of 10%.

Retiree Life Insurance:

Costs are based on an average discount rate of 2.74% and assumed EROA of 3.30%.

401(k):

Assumptions used for the 401(k) are based upon the employee demographics as of August 2020. Additional assumptions include wage increases for exempt, nonexempt, and union employees.

Pension:

The assumptions used for pension costs are a 2.70% discount rate and a long-term rate of return of 7.0%. Please refer to Section V of PGE Exhibit 400 for more detail on how these assumptions are derived.

Administration:

Assumptions are based on historical costs and program offerings.

Education:

Assumptions are based on projected usage rates, program costs and the maximum payout per participant.

Severance:

Forecast for 2022 is $0.

Miscellaneous:

Assumptions are based on current employee demographics and recent actual experience.

PGE's Response to Staff Standard Data Request 063, Attach A

Is

Filed in electronic format

July 19, 2021

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Standard Data Request 070
Dated March 10, 2015

Staff note: This is PGE's response to SDR 078

Request:

Please provide a table in the format below (See Table 1) of all internal accounts used by the utility. Organize the list so that the FERC account numbers are listed in numerical order and each internal account assigned to that FERC account is also in numerical order. For each internal account number include the description provided to employees to assist them in allocating the item to the appropriate internal account(s). Please also provide a cross-reference document that lists all internal account numbers in numerical order and indicates to which FERC number they are assigned (See Table 2).

Table 1

FERC Account	Internal Account Number	Description of Internal
908	XXXX1	
908	XXXX2	

Table 2

Internal Account	FERC Account
XXXX01	90X
XXXX02	59X

Response:

Attachment 078-A provides the requested account listing (i.e., for Table 1, see "Accounts" tab). Because PGE's accounts are FERC-based, there is no additional detail for Table 2.

PGE's Response to Staff Standard Data Request 78 Attach A

Is

Filed in electronic format

How Much Does Access Control Cost Per Door?

ACME Locksmith Commercial Door Hardware & Security, Keyless Entry / Access Control, Safety & Security Blog

Are you considering access control for your business? Let me start by saying that an access control system and a keyless entry system are just two different terms for the same thing. They are interchangeable. There are many advantages to access control systems, and I am often asked, "What will it cost to install access control?" The answer usually starts with, "What do you want the system to do?" There are many variable to pricing of keyless entry and this article is going to break them down for you.

If you are in Arizona, and would like a quote for your access control system, fill out our Access Control Estimate Request online.

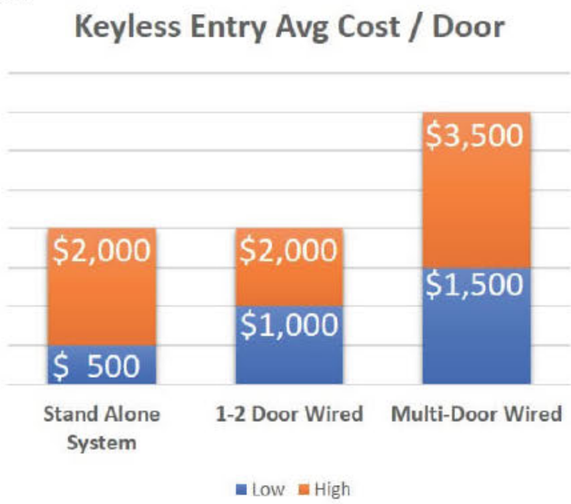
What Does Access Control Cost?

Access control prices vary dramatically based on the type of system. As a Locksmith company, we deal mainly with small businesses.

For small businesses, access control for a single door can be as little as $500 for an isolated, stand alone system. A wired access control system meant for 1-2 doors will be between $1000 and $2000 per door. Cost for access control is very feature

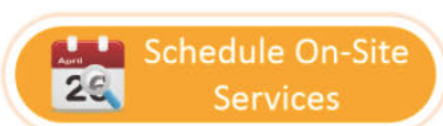
dependent. Systems can climb into several thousand per door for large-scale commercial businesses.

This cost per door graph quickly breaks down the low to high cost for a given type of keyless door entry.



How Much is an Access Control System in Arizona?

Access control systems in the Phoenix, AZ market run about 5-10% less than the above prices. This is due to the favorable cost of living in Arizona. If you are in the Phoenix Arizona market, you can schedule an Access Control Estimate with ACME Locksmith online.



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Quick Answers to Frequent Questions

Is There a Difference Between Residential & Commercial Keyless Entry −

Yes, commercial grade locks are built to withstand heavy use and have anti-vandal, anti-tamper capabilities. Many can also be installed outside on gates as they are weatherproof on both sides. This article talks about commercial access control cost.

What is the Cost per Door for Keyless Entry? +

What Types of Access Control Systems are Available? +

Can I Save Cost by Installing Keyless Entry Myself? +

What are the Types of Door Access Control Systems?

There are primarily three major categories of access control systems.

Traditional Wired System – The Most Expensive.

The first is the more traditional wired system. In a wired system you typically have a power supply, a controller that triggers whatever releases the door, and a software program so that you can add codes, cards or FOBs to access the door.

Wired keyless entry systems are the most expensive Access Control Systems because of the wiring, multiple electrical components and labor/installation cost. They can cost up to several thousand dollars per door and need to be installed by a security professional such as your local locksmith company.

But, complete wired systems are very beneficial if you have a large number of doors to access and you want to program/control all of those doors from one central location or online from any computer/phone with internet.

Standalone Access Control – The Most Affordable

The second category, and very popular with small businesses, are Standalone Access Control Systems. Usually everything needed for the system is contained within one device, such as a lock installed on the door, that allows programming for pin code and/or FOB access done at the lock itself.

Though the stand-alone-system locks are pretty expensive (ranging anywhere from $400 to over $1,500 in a commercial application with commercial grade locks), the cost savings comes from the fact that installation is much more simple. You don't have nearly as many components as you do in a wired system. In fact, you typically only have one component, the lock. So it's the lock itself that drives most of the expense.

The least expensive keyless entry is stand-alone keyless entry and for commercial grade product you can get pin-code access for as low as around $500 per door.

The standalone locks can look big and clunky, but that is because they are usually a commercial grade 1 lock (learn about lock grading) and since the can save you hundreds and even thousands of dollars, most of our customers prefer them.

The main disadvantage of this category is that it really is only good for a few doors. This is because each lock needs to be independently programmed at the lock itself and cannot all be controlled from one location. As you add doors, it can become an issue keeping them all up to date.

There are a few new solutions that will allow the locks to be programmed over the internet but as with all systems, this increases the price per door for the access control

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system.

My favorite stand alone products can be found on Amazon through the following links: Alarm Lock Trilogy (see on Amazon), Marks I-Qwik (see on Amazon) or Schlage NDE (see on Amazon), and Yale (see on Amazon). Note: Yale, Schlage NDE and Alarm lock have options that allow for control from one location. In some cases additional components are necessary. Talk to your local locksmith for options.

Wired Keyless Systems for 1-2 Door

In recent years a third category has emerged. Especially effective for small businesses it is a hybrid of the above two categories. It is similar to the stand-alone door access category in that its primary use is for a single door but similar to wired systems in that there are multiple components on the door working together, as opposed to a single lock.

This means that the components need to be wired together with someone that understands low voltage wiring. But those low voltage lines aren't run throughout a building for cost savings. In most cases, these systems can simply be plugged into an outlet near the door.

These systems really shine if there are only a few doors. One would choose these over the standalone systems because they are feature rich, offering capabilities not found in stand alone keyless systems, such as the ability to remote buzz people in with remote release feature.

The price of these keyless systems are coming down and currently only marginally higher than standalone system because while the individual components are less, the labor to install cost just a little more. Price will depend on whether it is a mag lock system or electronic strike and local city codes. **Expect to pay around $1000-$1500 per door for a single door access control system.**

You can buy a complete system as a kit through Amazon – a wide variety are available (see on Amazon).

For a more detailed description of the Components of an Access Control System and comparison of stand alone access control locks available, check out our post.

How Does Access Control Work and How Does it Affect Cost?

In a traditional door, some mechanical or physical action releases the door from the frame so that the door swings open. Typically unlocking a lock with a key. In Access Control Systems this is done electronically after credentials have been presented to the door granting someone access.

There are three main types of components that will hold/release the door so that it can be opened:


Magnetic Lock

- Magnetic locks. These hold the door closed via powerful electric magnets.
- Electronic strikes. These release the door lock so the door can swing freely even if the lock on the door has not been manually opened (turned).
- Electronic locks that release the lock from its locked state without having to have a key entered. These locks will either retract or release from the locked position electronically so the door can be opened.


Electric Strike


Electronic Lock

There are several credentials that can be used in access control to release the electrical component security the door.

- Remotes – such as a buzz in capability to let someone in. Adding this capability can increase the price of the system.
- PIN code – a 4-8 digit pin code assigned to employees to gain access.
- HID Cards or FOBS – held close to a reading device to release the door. Adding card swipe support increases the cost of the system and increases price due to the cards/FOBs provided. The more cards, the higher the cost.

In general, the more components you have to a system, the more the system will cost. How many components you need depends on which system you chose, the features you choose and the city building codes.

How do the Features of Access Control Systems Affect Price?

There are several features available to choose from for each type of keyless entry we've discussed. The more features you add, the more expensive the system. A base system is one that allows entry by user PIN code. Pin code are manually programmed at the lock that is securing the door. A pin-code only system is the cheapest access control system. From here, these features typically add cost (in approximate order of increasing cost):

- Scheduling – the lock is open or closed during specific hours / days.
- Card or FOBs instead of PIN code (the card is the credential that allows access). Both support of the card swipe feature and the cards themselves drive pricing.
- Software programming – setting up a computer that interfaces to the lock for automatic uploads, downloads, and user code / credential changes.
- Audit trail – the ability to track who entered and when via a report.
- Wireless communication with the lock – codes, audit trails, etc… can be accessed from any browser.

How do City Building Codes Impact Price?

Building codes vary from town to town. You really do need to consult with your local fire marshal, locksmith company or building inspector to find out what codes are necessary in order to install access control on a given door. Ignoring or installing a system incorrectly will result in your being liable should anything occur.

In general, everyone inside the building must have free egress (see our article What is Free Egress?) by a single motion in order to leave the building in case of an emergency.

That is, it only takes one action by a person to exit the door. For an Access Control door, this can either be through a manual action, such as pushing a panic bar or turning a lever to manually release the door, or an electronic action such as a “push to exit button” to release a magnetic lock. Every door must allow exist by every person without any key or special credential required.

Stand alone systems provide exit via mechanical means. Entry is via electronic credential (pin code or card) but exit stays mechanical. So there are no special code requirements that will alter the price.

If the exit is by an electrical means, such as the push to exit button found in many wired systems, many cities have code that requires a redundant system. This will increase the price of the system as it increases the number of components and labor cost in a wired keyless system. Stand alone access control systems have no such requirement as there will also be a mechanical exit available even if the lock fails.

Redundancy means that in a electric system should one thing fail another thing will still allow customers to exit the building. The most common method is to have a motion sensor on the inside of the door. When somebody approaches the door the motion sensor releases the electronic component securing the door. Should that fail the push to exit button is included as a backup measure to get out.

Even if your city does not require a redundant system to exit the building, it is still in your best interest to do so.

If I Install My Own Door Access Control Can I Save Money?

You can. Especially if the system is a stand alone, very basic system where you may be using just one PIN code.

But electronic systems and even the advanced stand alone systems are typical not do-it-yourself project for the inexperienced. Commercial systems are more complicated than residential and will require considerably more programming for the complex features. If all you want is a stand-alone keyless system with one user code that is accessible 24-7, then with the help of dealer installation videos or YouTube you should be able to handle the job.

When you get into scheduling, multiple users, audit trail support, etc….it’s considerably more complex even for stand alone system. Single door wired access control systems require a basic knowledge of low voltage electrical, understanding of tool usage, your city’s fire and building codes to prevent liability. Those without these skills should use or consult with a local locksmith for their access control installation. ACME Locksmith installs these all the time in Arizona and our prices are quite reasonable.

Amazon lists a large number of stand alone and complete single-door access control systems. Our favorites are:

- Stand alone: either Alarm Lock Trilogy (see on Amazon), Yale (see on Amazon), Marks I-Qwik (see on Amazon) or Schlage NDE (see on Amazon).
- Wired single door: a wide variety are available (see on Amazon).

Cost of Repair – If an Access Control / Keyless Entry System Fails?

Access control doors can be setup as either fail safe or fail secure.

Fail safe means that the electrical component holding the door will release when power is removed. In this situation there is always power at the door "holding" the door locks. When power is removed, it unlocks. If a magnetic lock were holding the door and power went out, the magnetic lock would release so you people can exit the business. In these cases, we often install a key override. Meaning doors will also be manually locked by a key so when the system fails, people with keys can still access the property, so even the system is broke and will need to be fixed, you won't be locked out and you will be able to secure the building by key. This is the most common installation required of most business by city code.

Fail secure means that the door unlocks when power is applied. So when there is no power, the door stays secure.

Which is chosen depends on the application but you should always include a mechanical method to secure the door for fail safe mode and a method to open the door mechanically for fail secure. As an example, a business may have a buzz in capability installed on their door to allow people in during the day. If power fails during the day or at night in fail safe mode the door becomes unlocked. A mechanical method of locking the door should be left in place to account for this.

As an example, for our offices we use card swipe on a electronic single door. At night the last manager leaving mechanically locks the door. In the morning the first manager arriving mechanically unlocks it. During the day, credentials are used by employees to gain access.

Repair cost will depend on what has gone wrong but will always be less than the cost of installation. Worst case for stand alone keyless door entry is the replacement of the part. Cost will be essentially the same as the original installation. You local locksmith can help diagnose and repair the components of an access control system.

Electrical, wired door access will certainly always be less than the original. Because only one component will fail and need to be replaced. Although this sounds better, because there are more electrical components, failure will likely occur more often than the stand alone keyless entry.

ACME Locksmith

ACME Locksmith is Arizona's #1 Rated Locksmith. We have been performing lock and key services in Arizona for over 20 years. In that time ACME Locksmith has serviced over 100,000 customers.

- Over 1900 5-Star Rated, Verifiable Arizona Customer Reviews
- Super Service Award Winner Eight Years Running
- Selected as an Angie List Phoenix-Best Contractor
- BBB International Marketplace Excellence Award Finalist
- BBB Ethics Award Winner – The Only Locksmith to Ever Win this Award

Details About ACME Locksmith

How Much Do Access Control Systems Cost?

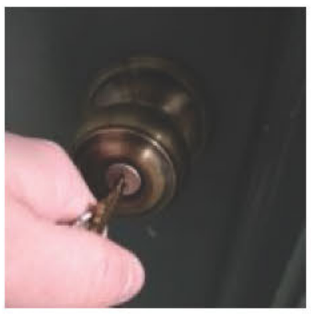
Access Control Pricing: Average Cost Per Door

A reliable, secure, and convenient access control system is a must-have for your property or facility. Today, there are a multitude of options with many different features and benefits, including keypad, biometric, and smartphone access control systems. Likewise, access control pricing can significantly vary from system to system.

No matter what access control solution you consider, remember that most solutions (other than a commercial smart lock or a traditional physical lock & key) must begin with an electric lock. With an electric lock, comes separate costs.

Here is a list of the average costs per door of popular types of access control systems:

Cost of Physical Keys/Locks for Access Control



Rekeying locks and replacing keys quickly adds up.

Keys are frequently lost, or users may leave an organization and not return their physical key. When this happens, changing the door locks or rekeying the lock is critical to ensure a safe environment.

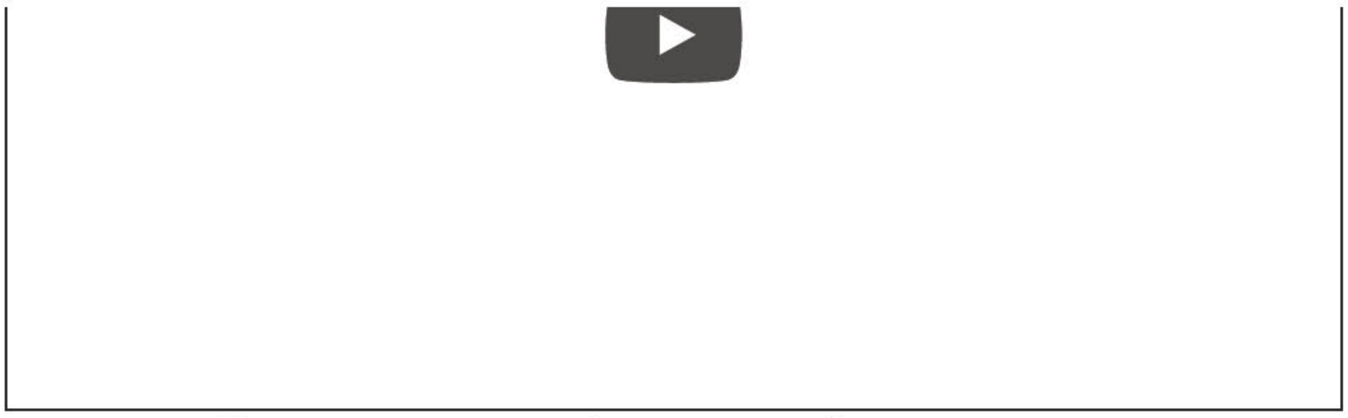
Whether you need to simply rekey the lock and purchase new keys or change out the lock hardware all together is impacted by several factors. The time it takes to rekey an individual lock is a matter of minutes, while removing the lock from the door takes longer. For an experienced locksmith, cutting a new key should take less than 2 minutes. Replacement keys can range from $2 for a simple key to $70 for a coded key. Ultimately, you're going to spend anywhere from $100 to $400 per door. If it's an emergency or an after-hours situation, expect to pay even more to get someone to your building.

Cost of Keypad Access Control Systems

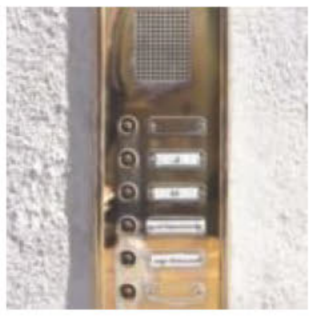
Keypad entry systems range from $400 to over $1,500 per door with hardware, wiring, and installation. Most keypad entry systems take a short time to install, but ultimately, it will depend on the wiring of your building. While keypad systems can offer one of the lowest cost options, they also present one of the least secure options. People can easily share codes with others. It's also essential to consider the physical deterioration of the numbers on the keypad. The wear on the numbers can indicate the numbers used in the code. Also, a keypad is easily hacked (watch the video below). One benefit of the keypad is the short time it takes to change the code. There's no cost (other than time) to change the code, but everyone accessing the building must commit new code to memory. Unfortunately, someone must be present to recode the keypad.

Why You Shouldn't Use a Keypad for Access Control

Need Help ?



Cost of Intercom (Buzzer) Access Control Systems



Door buzzer systems have to be actively managed.

Telephone intercom or buzzer access control systems range between $450-10,000. A building telecom entry system can start as low as $450 for the intercom and installation (a basic buzzer system). The total cost can go as high as $10,000 or more when you have high-quality video, storage, reception features, and more. Installation may take 1-2 hours per intercom, depending on the complexity of the wiring in your building. Since there's no physical card, resetting access requires about 15 minutes from an administrator. Most telephone intercom buzzer systems are older and demand someone to be onsite.

Cost of Biometric Access Control System

Biometric door access control system prices are quite high.

On average, prices for biometric access control systems range from a total of $2,500-10,000 per door when you factor in the biometric scanner, electronic locking system, software integration, and installation. Although biometric systems, which use fingerprint, handprint, or iris scanning to gain access, can be costly, there is no need to purchase and manage keycards. Installation of biometric hardware should take about 20 minutes per door. Still, the whole process will require more time to install software and connect the system to a network. Next, you'll need to allocate at least 15-20 minutes to set up biometric access and train each employee to use the system.

Cost of Key Card Entry System

People frequently share key cards, creating security gaps.

A card and reader access solution generally costs $1,500-2,500 per door. That number includes $1,000-1,500 for the reader, software and installation, $3-5 (plus shipping) per keycard, and monthly service fees that can range from $10-100. Installation is reasonably straightforward, taking under an hour per door, but that doesn't account for the hours of work required to issue key cards manually. Remote management is possible for some systems, but in most cases, someone will need to be onsite to process new key cards and manage user access.

Cost of Key Fob Access Control Systems

When it comes to a key fob and reader access control system, the installation per door is very similar to a key card: $1,500-2,500 per door. Instead of waving a key card in front of the reader, people use a key fob, allowing stored data to exchange via radio waves. Once installed, the costs don't end there. Every time the software requires an upgrade, expect another charge. On top of that, key fobs are much more costly than key cards, costing at least $5 or more per fob. Every time a key fob is lost, the property manager will need to spend time removing the lost fob and manually adding a new one to the system. One property manager estimated spending 15 minutes per tenant every year, administering the system. With a pay rate of $20/hour, a system administrator managing 200 tenants would cost an additional $1,000 per year.

Scan your phone and you're in!

or a **commercial smart lock** that's battery-powered.

The cost of **VIZpin access control reader** (connected to an electronic door lock) is $299 per reader. The VIZpin system includes a free LITE access management service including 5 keys. A paid annual PLUS service is available starting with 500 smartphone credentials, including all upgrades, for an additional yearly fee. The industry average cost for smartphone door readers and hardware averages from $600 to $1,200 per door. You can usually install a smartphone access control system for less than $1,000 per door. Installation is fast and straightforward, requiring only a door strike, power supply, and reader. Also, access can be easily granted or revoked at any time from anywhere. Because it's managed in the cloud, hardware updates are available immediately at no cost.

Smartphone-based access offers an affordable option that does not involve the purchase and management of keycards, costly hardware, or the need to connect to a local network. Many owners and managers are upgrading to a smartphone-based system to solve a variety of issues other systems leave unresolved. People offer many reasons for changing, some obvious and some you may find surprising – you can read more here.

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August 30, 2021

To: Brian Fjeldheim
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 449
Dated August 16, 2021

Request:

Regarding PGE's cybersecurity policies and procedures, please provide:

a) A narrative overview describing how the Company secures their corporate and customer data as well as their digital infrastructure.
b) A narrative description of the primary measures the Company is taking to improve and strengthen cybersecurity.

Response:

a. PGE has cyber security specific policies and standards outlining how PGE data is to be handled, transmitted, and stored based on its assigned classification and medium type. PGE continues to evaluate Information Technology (IT) and Operational Technology (OT) with ongoing risk assessments for new and existing projects. These policies and standards include:

   Policies:

   - Information Security Policy – this corporate policy sets out Management's Intent on how information and technology assets must be safeguarded at PGE. This policy provides technical requirements to meet the governance outlined in this policy.
   - Information Confidentiality Policy – explains the classifications used by PGE for protecting information and user responsibilities.
   - Technology Acceptable Use Policy - this corporate policy sets out requirements for the use of PGE-provided or approved Technology Assets for PGE operations.

   Standards:

   - Backup and Retention Security Standard – provides security requirements for the backup and restoration of a system, service, or information.
   - Cloud Computing Security Standard – provides requirements for the acquisition, development, management, and termination of Cloud Computing Solutions for PGE operations.

- Configuration Management Standard – provides requirements for implementing and managing secure configuration settings on PGE technology assets.
- Information Access Control Standard – outlines requirements for managing and limiting access to PGE technology assets and information.
- Information Confidentiality and Encryption Standard – provides requirements for the handling, sending, and disposal of PGE information based on its classification.
- Logging, Monitoring, and Auditing Standard – provides requirements for ensuring activity on PGE technology assets is monitored, recorded, and reviewed.
- Mobile Computing Standard – explains the requirements for the use of cell phones, smartphones, and tablets for PGE business.
- Network Security Standard – provides requirements ensuring a secure environment for PGE traffic, data, and activity.
- Patching and Vulnerability Management Standard – provides requirements for identification and timely remediation of security weaknesses on PGE technology assets.
- Secure Coding Standard – provides security requirements for application development.
- System and Service Lifecycle Standard – provides requirements for the development, implementation, maintenance, and disposal of PGE technology assets.

b. PGE continues to improve cybersecurity policy and standards language for both the IT and OT environments. Our project management lifecycle includes controls to avoid, detect, counteract, or minimize security risks to information, computer systems, or other assets. All projects are evaluated, and risk determinations are documented and where necessary presented to appropriate management for mitigation or acceptance.

August 30, 2021

To: Brian Fjeldheim
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 450
Dated August 24, 2021

Request:

Has PGE ever had a cybersecurity audit performed by a federal or state agency? If yes, please provide a summary of the most recent cybersecurity audit findings.

Response:

PGE has not been subject to a federal or state agency cybersecurity audit and neither is it subject to a periodic federal or state agency cybersecurity audit. PGE, however, has had audits of our compliance with North American Electric Reliability Corporation (NERC) Reliability Standards, including the Critical Infrastructure Protection (CIP) standards. Those Reliability Standards are made mandatory by the Federal Energy Regulatory Commission. Western Electricity Coordinating Council (WECC) conducts triennial audits of PGE's compliance with a subset of the NERC standards. PGE's most recent WECC audit was held in June of 2020. That audit evaluated PGE for compliance with 14 CIP requirements for the period of April 12, 2017, to March 16, 2020. The audit found one instance of potential non-compliance. The audit alleged that PGE had a potential non-compliance with CIP-010-2 Requirement 4 because PGE failed to include Sections 2.3 and 3.2.2 security objectives in its documented plan for Transient Cyber Assets and Removable Media used with its high impact BES Cyber Systems. WECC has yet to take any further action regarding this alleged violation.

August 30, 2021

To: Brian Fjeldheim
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 451
Dated August 16, 2021

Request:

On an annual basis, for each of the past five years, how much money did PGE spend on cybersecurity? Please indicate whether these expenditures were recorded as expenses or capital additions/rate base.

Response:

Expenses in the table below identify cybersecurity O&M expenses. Please see PGE's response to Data Request No. 461 for capital investment in cybersecurity.

2018	2019	2020	2021	2022
$ 10,514	$ 19,115	$ 15,333	$ 18,924	$ 19,606

October 6, 2021

To: Curtis Dlouhy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 866
Dated September 22, 2021

Request:

Refer to PGE/200, Tooman – Batzler/13 at line 15. Please provide the total depreciation expense if the Colstrip Decommissioning Date is moved from 2027 to 2025.

Response:

If Colstrip's depreciable life is moved from 2027 to 2025, the depreciation expense associated with Colstrip would increase from the $23,713,787 currently included in PGE's test year revenue requirement to $35,577,551.

for less net salvage. The Stipulating Parties agreed upon a net salvage rate of -55 percent for this Depreciation Study.

For subaccounts 370.01, Meters-AMI and 370.02, Meters-Retained, PGE recommended a net salvage rate of -5 percent, based upon expectations of future costs. Staff recommended a net salvage rate of 0 percent, based upon the limited retirement activity. The Stipulating Parties agreed to compromise on a net salvage position of -2 percent for this Depreciation Study.

D. Colstrip Probable Retirement Date

Q. Please provide depreciation information regarding the Colstrip Plant.

A. PGE owns 20 percent of two coal plants in Montana, Colstrip Units 3 and 4. On October 12, 2016, pursuant to 2016 Oregon Laws, Chapter 28 (SB 1547), Section 1, PGE proposed an automatic adjustment clause in Docket No. ADV 391, Advice 16-15 to implement the revenue requirement effects resulting from a change in the Colstrip Generating Facility (Colstrip) end-of-life of December 31, 2042 to December 31, 2030. The Commission granted PGE recovery of the Colstrip incremental depreciation and decommissioning costs via Schedule 146, an automatic adjustment clause rate schedule.

More recently, Governor Kate Brown issued Executive Order No. 20-04, calling for substantial reductions in economywide greenhouse gas emissions (GHG). To support Oregon reaching its decarbonization goals and provide increasingly clean electricity, PGE proposed an adjustment to Colstrip end-of-life from December 31, 2030 to December 31, 2027 in this Depreciation Study.

Q. Did the Stipulating Parties agree with PGE's proposed retirement date for Colstrip?

A. CUB proposed to change the Colstrip probable retirement date from December 31, 2027 (proposed in the Depreciation Study) to December 31, 2025.

Q. What is the basis for CUB's proposal to adjust the Colstrip probable retirement date from December 31, 2027 to December 31, 2025?

A. The basis for CUB's proposal is PGE's Colstrip Enabling Study, performed by PGE in 2020 in response to the Commission request for further analysis on the impact of the early removal of Colstrip from PGE's portfolio. The conclusion of the study is that the removal of Colstrip from PGE's portfolio by December 31, 2025 provides PGE's customers the greatest reduction of cost and risk in the Integrated Resource Plan (IRP) portfolio metrics. The December 31, 2025 date also aligns with Washington's Clean Energy Transformation Act (CETA) legislation that was passed in 2019, which aligns PGE with the Washington co-owners of Colstrip, Avista and Puget Sound Energy.

Setting the depreciable life to match the life used by the Washington utilities sets depreciation rates in a manner that minimizes the risk to PGE and its customers. For example, in Avista's 2019 Washington general rate case, Avista agreed to not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life beyond December 31, 2025.[3] As informed by the Colstrip enabling study, setting a depreciable life of 2025 for the plant minimizes cost and risk to PGE's customers.

Q. Are there other reasons that support a December 31, 2025 probable retirement date for Colstrip?

A. Yes. Colstrip is supplied coal from the Rosebud mine, which is owned by the Westmoreland Coal Company. In October 2018, Westmoreland Coal company declared Chapter 11 Bankruptcy. In 2019, the regulated utility owners of Colstrip signed a new six-year contract

[3] WUTC Docket UE-190334.

to supply the power plant with coal until 2025. Setting a 2025 depreciation date for Colstrip enables PGE to align its interest in the facility with the current Colstrip coal contract. Given the speculative future that the coal industry faces, it is critical that PGE not be exposed to the price fluctuations and risk that a potential future coal contract brings. By setting a depreciation date of 2025, PGE can exit the plant at a time that would mitigate this exposure. If Colstrip's depreciable life were set beyond 2025, the Company may have to negotiate a future coal supply contract where the costs and risks are uncertain and therefore may pose cost and risk to PGE's customers.

Q. Did the Stipulating Parties agree with CUB's adjustment?

A. Yes, the Stipulating Parties agreed to set the Colstrip probable retirement date to December 31, 2025. The change represents an approximate $4.5 million increase to the Colstrip annual depreciation expense as filed based on depreciable plant as of December 31, 2019.

Q. Why does Staff support CUB's adjustment to the Colstrip probable retirement date?

A. The Colstrip Units 1 and 2 were shut down in January, 2020. The Units 3 and 4 are jointly-owned by PGE, Puget Sound Energy (PSE), Avista Corp, PacifiCorp, NorthWestern Energy, and Talen. PGE has a 20 percent ownership share of Units 3 and 4. The units began operating in 1985 and 1986. NorthWestern Energy announced in December 2020 it had reached an agreement to buy PSE's 25 percent share of Unit 4 of the Colstrip plant for $1. PSE's selling decision was made after determining they could not make the units "economically viable." By May 2025, Washington's PSE will no longer be able to serve Washington load with coal-fired power.

Accordingly, Staff supported the CUB-proposed end of depreciation (retirement) date of December 31, 2025 for Colstrip power plant for the following reasons:

- PGE's enabling study concludes that PGE customers are better off with Colstrip out of PGE's portfolio by 2025;
- A longer coal power plant life is no longer financially viable;
- Currently, the net coal plant value is low, and the asset is close to being fully depreciated. However, the decommissioning cost is very high at this time compared to the period that the coal power plant was built, because of the labor costs and environmental remediation costs. Please note, decommissioning cost is included in the depreciation rate as a terminal net salvage value.

Q. Does the Stipulation represent a complete resolution of all issues in this docket?

A. Yes. All the Stipulating Parties know that the settlement reached required each one of them to make some compromises on the asset depreciation, and all parties accepted this presupposition during the settlement meetings. For settlement purposes, the Stipulating Parties all compromised and acquiesced on some issues.

Q. Please explain why the Commission should adopt the Stipulation.

A. The final adjustment decisions were made based on the combination of the considerations of PGE's plant retirement patterns and in-house engineering opinion, the industry average level, and analyst experience. Based on scientific evidence and the scientific method, the Stipulation is consistent with the asset retirement pattern and it meets energy industry expectations. The Stipulation represents a fair and reasonable level of depreciation expenses to be included in depreciation rates.

Q. Please summarize the Stipulating Parties' joint recommendations to the Commission.

A. We recommend that the Commission approve the Stipulation. We also recommend that the Commission order PGE to implement the probable retirement dates, depreciation curve-recommend that the reserves transfer to Colstrip be limited to Other Production Accounts and Transmission reserve accounts. While not identical, transmission costs are allocated to rate classes similarly to production costs, thus avoiding class allocation equity issues.

Q. DO ANY OTHER FACTORS SUPPORT YOUR RECOMMENDATION?

A. PGE occasionally transfers assets at their net book value.[46/] If PGE maintains high excess reserves, there is some risk these reserves could pass on to other utilities through a property sale.

V. REMOVAL OF COLSTRIP FROM RATES

Q. PLEASE SUMMARIZE THIS ISSUE.

A. In the second Paragraph 5 of the Stipulation (likely misnumbered), the Stipulating Parties recommend that PGE accelerate capital recovery of Colstrip to 2025. This is supported by economic analysis performed by PGE demonstrating that Colstrip is not economical to operate after 2025.[47/] However, PGE has made no commitment to retire Colstrip[48/] or remove ongoing costs and benefits of Colstrip from rates after 2025, regardless of the Company's own study demonstrating such costs to be uneconomic. I recommend that as part of accelerating capital recovery of Colstrip, the Commission preclude PGE from passing any uneconomic operating costs on to customers for more than five years after PGE has received full capital recovery. This may necessitate PGE operating Colstrip as a merchant generator.

[46/] AWEC/102 at 12 (PGE Response to AWEC DR 42).

[47/] PGE Colstrip Enabling Study, available at: https://assets.ctfassets.net/416ywc1laqmd/2AK9jf4GCmd1tyaLA8EODE/fb40144334f40fab7cc2e001676f1977/2020-colstrip-enabling-study.pdf

[48/] AWEC/102 at 11 (PGE Response to AWEC DR 38). PGE Response to AWEC DR 38 indicates PGE has not initiated an early closure vote in response to its enabling study.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. It is not fair for customers to bear both the burden of accelerated depreciation and uneconomic Colstrip generation. However, SB 1547 appears to provide PGE the opportunity to do just that. SB 1547 states that, for up to a five-year period following the date Colstrip is fully depreciated, "the commission shall authorize [PGE] … to include in the company's allocation of electricity the costs and benefits associated with [Colstrip] if: (a) [PGE] requests the commission to authorize the allocation of electricity."[49/] Consequently, the Commission appears to have no choice but to allow PGE to continue including the ongoing operating costs and power cost benefits of Colstrip in customer rates for five years after this plant is fully depreciated. Under the Stipulation, this means customers may continue to pay for Colstrip until 2030 even though PGE's own analysis shows that doing so will result in a net cost to customers.[50/]

An additional benefit of my recommendation in the previous section to transfer excess reserves to buy down Colstrip's undepreciated investment is that this will result in Colstrip becoming fully depreciated likely sometime in 2022.[51/] The five-year time limit provided in SB 1547 will then expire in 2027, removing this uneconomic resource from customer rates three years earlier than would occur under the Stipulation.

49/ ORS 757.518(4)(a).

50/ AWEC/102 at 4, 10 (PGE Response to AWEC DRs 18 and 37). PGE Response to AWEC DR 18 confirms PGE intends to pass any uneconomic costs to customers. PGE Response to AWEC DR 37 confirms that PGE intends to rely on SB 1547 provisions to remove the Commissions discretion regarding this.

51/ The specific date will depend on when the Commission issues a final order in this docket and when PGE transfers the excess reserves to the Colstrip accounts.

and supporting analysis to deviate from the estimates agreed to by the parties to the Stipulation.

II. THEORETICAL RESERVE IMBALANCE

Q. What is a theoretical reserve imbalance?

A. A theoretical reserve imbalance ("TRI" or "imbalance") is calculated as the difference between a company's book accumulated depreciation, or book reserve, and the calculated accrued depreciation, or theoretical reserve. We should note that in some proceedings in this and other jurisdictions, different terms have been used for the theoretical reserve imbalance, including "theoretical reserve variance," "excess reserve," "reserve surplus" or "reserve deficit" and "theoretical excess depreciation reserve." For this testimony we will use the term "theoretical reserve imbalance," which is consistent with the terminology used in the National Association of Regulatory Utility Commissioners' ("NARUC") publication *Public Utility Depreciation Practices*. Terms such as "excess reserve," and "reserve surplus" can be misleading, since they imply that the theoretical reserve is a more precise figure than it is. These terms also suggest that accumulated depreciation represents a pool of money or funds that can be used for various financial objectives, which is not the case.

Q. What is the book reserve?

A. The book reserve, also referred to as the "book accumulated depreciation" or the "accumulated provision for depreciation," is a running total of historical depreciation activity. It is equal to the historical depreciation accruals, less retirements and cost of removal, plus historical gross salvage. The book reserve also represents a reduction to the original cost of plant when calculating rate base.

Q. What is the theoretical reserve?

A. The theoretical reserve is an estimate of the accumulated depreciation based on the current plant balances and depreciation parameters (service life and net salvage estimates) at a specific point in time. It is equal to the portion of the depreciable cost of plant that will not be allocated to expense through future whole life depreciation accruals based on the current forecasts of service life and net salvage. The theoretical reserve is also referred to as the "Calculated Accrued Depreciation" or "CAD."

Q. How is the theoretical reserve calculated?

A. Using the average service life procedure employed for this study, the theoretical reserve is calculated for each vintage in each depreciable group using the following formula:

Theoretical Reserve = (Original Cost - Net Salvage) x (1-Remaining Life/Average Service Life)

The remaining life and average service life are determined for each vintage (year of installation) based on the survivor curve estimate (life and dispersion pattern). The theoretical reserve for an account is equal to the sum of the theoretical reserve amounts for each vintage.

Q. Why is it called theoretical?

A. The reserve is called theoretical because it is not based upon actual recorded depreciation resulting from the application of depreciation rates used by the Company and approved by the Commission. Instead, it is an estimate based on the formula described previously.

Q. Why does one calculate a theoretical reserve?

A. A theoretical reserve is calculated as an analytical tool or benchmark to identify how current estimates compare to the provisions using previous estimates in calculating annual depreciation. It can also be used as a basis to allocate the book reserve to accounts, subaccounts or vintages of plant. A theoretical reserve calculation provides a snapshot of the reserve, valid only at the time it is calculated, since any changes in the proposed parameters or plant and reserve activity will change the theoretical reserve.

Q. Mr. Kaufman argues that the difference in the book and theoretical reserve represents an "excess" in the accumulated provision for depreciation. Is that accurate?

A. No. While there is a difference between book accumulated depreciation and the theoretical depreciation reserve, this amount is not an "excess." It is simply a theoretical calculation of the difference between the actual accumulated depreciation, based on the Company's historical experience and Commission-approved depreciation rates, and a theoretical amount based solely on the proposed depreciation parameters. Depreciation is a prospective calculation, and thus changes as life and net salvage parameters change in future studies. As the Company moves through time with varying experience, this difference can change positively or negatively.

There are also reasons that we might expect the theoretical reserve imbalance to decrease in the future. The electric industry in Oregon and neighboring states is going through a significant transition from fossil fuels to other energy sources. It is very possible that, as the electric system is updated to incorporate these fuel sources, assets will be replaced at a more rapid pace than has occurred historically. Further, PGE has, in recent years, made significant investments to their Transmission and Distribution systems, and its service territory continues to experience the effects of climate change and severe weather (wildfires in 2020 and a major ice storm in 2021) which result in unanticipated damages to those systems.

Given these circumstances, the theoretical reserve imbalance will decrease and could even become a negative amount. If Mr. Kaufman's proposal to effectively reduce this amount to zero over the next ten years were adopted, it is very likely that the theoretical reserve imbalance would be negative in future depreciation studies.

Q. Is the theoretical reserve imbalance harmful to current customers?

A. No. In fact, current customers benefit from the existence of a theoretical reserve imbalance in two ways. The first is that depreciation based on the remaining life technique is lower than it otherwise would be. The second is that, because the book reserve is a reduction to the original cost of plant, rate base is lower and customers pay a lower return on rate base. Current customers are not harmed from a theoretical reserve imbalance that developed over many years.

Q. What is Mr. Kaufman's proposal in this case related to the theoretical reserve imbalance?

A. Mr. Kaufman is proposing (1) to transfer "excess" reserve from accounts in various functions to the steam production accounts to equal the future accruals expected for Colstrip and (2) to amortize the remaining portion of the theoretical reserve imbalance over a ten-year period.

Q. Is Mr. Kaufman's proposal a common practice in the industry?

A. No. Most utilities, Commissions and depreciation texts agree that theoretical reserve differences frequently exist and are best resolved using the remaining life technique. The remaining life technique is the most widely accepted approach and should be used unless unique and significant circumstances otherwise warrant deviation from this practice. While Mr. Kaufman discusses at length the size of the theoretical reserve imbalance, he does not provide any unique circumstances that would require addressing the reserve imbalance more quickly than occurs from using the remaining life technique. The theoretical reserve imbalance is developed over many years and is based on estimates of the future. It, therefore, should not be resolved in a short period of time, as Mr. Kaufman proposes. It is more appropriate to allocate costs through depreciation over the remaining time the Company's assets will be in service using the remaining life technique. Mr. Kaufman's amortization approach is a short-term subsidy for current customers that will result in increased costs for future customers.

Further, his proposal to transfer reserve across functions is not appropriate. While he minimizes such issues in his testimony, there are cost allocation issues and potential jurisdictional issues with transferring reserves from other functions such as transmission and distribution to generation. For this reason, the Federal Energy Regulatory Commission ("FERC") has not typically allowed transfers of reserves across functions.

Q. Has the Commission accepted the use of the remaining life technique for PGE in the past?

A. Yes. The Company has used the remaining life technique for developing depreciation rates for many years. The remaining life technique has been accepted by the Commission for other utility companies in Oregon as well. To our knowledge, Mr. Kaufman's approach has not been approved in Oregon.

Q. Referring to authoritative sources, what does the National Association of Regulatory Utility Commissioners (NARUC) say regarding this issue?

A. NARUC makes several comments regarding theoretical reserve imbalances in its publication *Public Utility Depreciation Practices*. On page 189, NARUC states:

> When a depreciation reserve imbalance exists, one should investigate why past depreciation rates, average service lives, salvage, or cost of

> removal amounts differ from the current estimates. Care should be taken to analyze these effects before correcting for the reserve imbalances. Instances occur where subsequent experience shows the original estimates no longer to be appropriate. It should be noted that only after plant has lived its entire useful life will the true depreciation parameters become known.[1]

Q. Does NARUC provide additional guidance addressing the remaining life technique?

A. Yes. NARUC also notes that:

> The desirability of using the remaining life technique is that any necessary adjustments of depreciation reserves, because of changes to the estimates of life and net salvage, are accrued automatically over the remaining life of the property. Once commenced, adjustments to the depreciation reserve, outside of those inherent in the remaining life rate would require regulatory approval.[2]

Combined with the NARUC passage cited earlier urging caution, NARUC's recommendation is that for companies like PGE that use the remaining life technique, any accelerated amortization, such as proposed by Mr. Kaufman, must be based on unique circumstances that justify specific Commission approval. Despite Mr. Kaufman's claims, such circumstances do not exist for PGE, and the size of the reserve imbalance alone does not justify such treatment.

[1] *Public Utility Depreciation Practices*, NARUC, 1996, pp. 189.
[2] NARUC, p. 65.

We note that Mr. Kaufman cites this same passage in his testimony. However, he completely misinterprets the meaning of this passage, claiming that NARUC "explicitly calls out the necessity for commissions to approve depreciation reserve adjustments for utilities that rely on the Remaining Life Technique."[3] This is, in fact, the exact opposite of what NARUC says, and in no way does NARUC indicate a "necessity" for reserve adjustments when the remaining life technique is used. When one reads the full passage, it is clear that NARUC means that the reserve adjustments are not necessary if the remaining life technique is used because the remaining life automatically corrects any reserve imbalances. Any explicit adjustments would be relatively rare and, as a result, would "*require* regulatory approval" (emphasis added). That Mr. Kaufman's interpretation is incorrect is also evidenced by the fact that the vast majority of depreciation studies using the remaining life technique do not incorporate a reserve adjustment similar to what Mr. Kaufman proposes.

Q. Mr. Kaufman cites a handful of cases in which amortizations of theoretical reserve imbalances were adopted. Are these common?

A. No. Additionally, for some of the cases cited by Mr. Kaufman, subsequent depreciation studies resulted in negative theoretical reserve imbalances. That is, subsequent experience indicated that such adjustments were incorrect. For example, he cites an

[3] Kaufman at 23.

amortization of the reserve imbalance for PacifiCorp's Hunter Plant approved by the Idaho Commission. However, in PacifiCorp's more recent depreciation study this plant had a negative reserve imbalance. This illustrates the concept that reserve imbalances change over time and provides a reason why dramatic actions, such as proposed by Mr. Kaufman, are not sound policy. Additionally, PacifiCorp also files studies in Oregon and the same treatment was not adopted here as was in Idaho.

We note that Mr. Kaufman has only cited a handful of cases over the course of more than a decade in which a similar proposal to his was adopted. One case is from New York, which does not use the remaining life technique, and so is not relevant. That he has cited so few cases illustrates that such approaches are, in fact, quite rare. In the majority of depreciation studies across the country, the remaining life technique is used, and an additional amortization is unnecessary.

Notably, Mr. Kaufman has not cited any cases from Oregon. He also does not note that the FERC has rejected his approach and found that it is not consistent with the Uniform System of Accounts (USofA).

Q. Please discuss the case in which the FERC rejected an amortization of the theoretical reserve imbalance.

A. Progress Energy Florida (now Duke Energy Florida) filed its depreciation study before the FERC in Docket No. ER11-2584-000. FERC stated in its Order:

> In this regard we note that this Commission has addressed any alleged excess or deficiency in depreciation reserves through adjustment of depreciation rates that eliminate such excess or deficiency over the remaining life of a utility's plant, rather than any shorter period.[4]

In other words, an accelerated amortization of the reserve was not accepted.

Additionally, FERC further stated in Docket No. ER11-3584-000 that:

> In Order No. 618 and in the February 28 Order, the Commission stated that the cost of property used in utility operations should be allocated in a "systematic and rational manner" to periods during which the property is used in utility operations, i.e., over the property's remaining estimated useful service life. For this reason, changes in asset depreciation estimates, including cost of removal, should be made prospectively over the asset's remaining life. Florida Power proposes to adjust its depreciation reserves by $65,840,613 in 2010 and intends to adjust its depreciation reserves by varying amounts in 2011 through 2013 rather than allocating the excess depreciation reserves over the remaining service lives of the related utility plant. While these adjustments may be acceptable for retail ratemaking purposes, they do not conform to our requirements for allocating the costs of utility plant over their service lives. Accordingly, we will direct Florida Power to reinstate all such adjustments to its depreciation reserves (Account 108). Florida Power must also re-file its 2010 FERC Form No. 1 to reflect the restatement of its depreciation reserves.[5]

Q. Based on the FERC's decision cited above, does the FERC consider Mr. Kaufman's proposal consistent with the USofA?

[4] Order in FERC Docket No. ER11-2584-000, p. 10, footnote 44.
[5] Order in FERC Docket No. ER11-3584-000, paragraph 9. (Emphasis added).

A. No. The cited passages above make clear the FERC's opinion that the USofA requires that any reserve imbalances be allocated over the remaining lives of a Company's assets (e.g., by using the remaining life technique). Mr. Kaufman's proposal would not allocate the Company's costs over the service lives of its assets in a systematic and rational manner and, therefore, would not be consistent with the USofA. In addition, there is no explanation or rationale to support why a ten-year amortization period is appropriate and appears to be arbitrary. Thus, this argument lacks context and support.

Q. Mr. Kaufman claims that the theoretical reserve imbalance means that "future customers are receiving nearly free use" of assets.[6] Is he correct?

A. No. Mr. Kaufman's statement is based on one very small account that includes assets he refers to as possibly being "obsolete."[7] When one considers the rest of the Company's accounts, it is clear that Mr. Kaufman fundamentally misunderstands the Company's theoretical reserve imbalance. The theoretical reserve imbalance is developed over the entire history of the Company. It is not only the result of what current customers have paid but also many previous generations of customers. It does not mean that there have been intergenerational subsidies. Theoretical reserve imbalances arise as service life and net characteristics evolve over time and do not necessarily mean that any generation of customers "over-" or "under-paid."

[6] Kaufman, p. 11, line 16.
[7] Kaufman, p. 11, line 4.

Q. On pages 10 to 12 of his testimony, Mr. Kaufman discusses Account 373.07, Sentinel Lighting Equipment. Please address his discussion of this account.

A. Mr. Kaufman devotes a significant portion of his testimony on an account that is both unusual and represents a small fraction of the Company's assets. Specifically, the balance for Account 373.07 represents less than 0.1% of the Company's plant in service. It also has had minimal activity in recent years and has been relatively close to fully depreciated for many years. It is not reasonable to extrapolate the experience of this account onto the billions of dollars invested in other accounts that have considerably more remaining years to recover through depreciation.

Further, the specifics of the account do not support Mr. Kaufman's conclusions. For example, this account has had an accumulated depreciation reserve that is greater than the plant in service for the account since at least 2012, and remaining life depreciation rates corresponding to this have been relatively low as a result. Thus, customers have not "over-paid" depreciation in this account for many years. Mr. Kaufman's proposal would give an even greater subsidy to current customers by producing negative depreciation expense for this account for the next ten years. After that, customers would then have to pay higher depreciation rates. Yet, Mr. Kaufman observes that the assets in this account are possibly obsolete.[8] If this

[8] Kaufman, p. 11, line 5

is true today, it would make little sense for customers to pay, ten years from now, more than they have paid since 2012.

More important, a similar situation does not occur for larger accounts. Indeed, the other account Mr. Kaufman discusses – Account 356, Overhead Conductors and Devices – has over $84 million remaining to recover through depreciation expense and is, therefore, not at all comparable. In other words, the unique situation of Account 373.07 does not mean drastic measures are appropriate for other accounts. Indeed, if one were so inclined, a more targeted adjustment to Account 373.07 could be accomplished while having minimal effect on the other accounts that comprise more than 99.9% of the Company's investments. That is, Mr. Kaufman's observations about one isolated account in no way provide support for his much more significant proposal that affects every account.

Further, it should be noted that the TRI for most of the Company's depreciable plant accounts (as of the study date of December 31, 2019) is within a range that is reasonable. The TRI for depreciable plant in total is 19% and for most accounts does not exceed 30%. The select accounts that Mr. Kaufman uses to illustrate his arguments are not representative of most of the Company's accounts.

Q. Does the existence of a theoretical reserve imbalance suggest there is a problem that must be remedied?

A. No. The theoretical reserve and the theoretical reserve imbalance are the result of a calculation that incorporates many assumptions, and that the theoretical reserve itself is a simple model of the very complex history of transactions that have resulted in current accumulated depreciation balances. For this reason, the theoretical reserve almost never matches the book reserve. The mere existence of a theoretical reserve is a function of the difficulty of modeling real world utility property and forecasting service life and net salvage. The theoretical reserve should not be confused with the "correct" book reserve.

Q. If the theoretical reserve is not a perfect measurement of accumulated depreciation, why is it calculated?

A. The calculation of a theoretical reserve is not required, nor is it necessary, when using the remaining life technique and is not used in the remaining life formula. Some analysts do not even calculate the theoretical reserve when performing depreciation studies that are based on the remaining life technique.[9] While the theoretical reserve can serve as a rough benchmark as to how current estimates compare to depreciation estimates and plant and reserve activity in the past, it should not be considered the "correct" reserve. Authoritative depreciation texts are clear that the status of the book reserve as compared to the theoretical reserve is not a prescription for necessary adjustments to the reserve.

[9] Gannett Fleming's calculations use the theoretical reserve for each vintage of plant to allocate the book reserve to each vintage. However, the theoretical reserve is not used as a basis for any other remaining life calculations. Other depreciation software does not allocate the book reserve to the vintage, and thus does not use the theoretical reserve for the calculations.

Q. What do Mr. Kaufman's claims assume?

A. There are two important implicit assumptions inherent in his claims that we will discuss here. These assumptions are:

1. Estimates made today are completely accurate.
2. Previous depreciation rates for the Company, as accepted by the Commission, were "incorrect."

We will begin with the first assumption, as the problems with this assumption help to demonstrate some of the problems with the second.

Q. Is the assumption that estimates made today are completely accurate, a valid assumption?

A. No. The estimation of depreciation is a very complex and difficult task requiring the forecast of events (e.g., retirements and net salvage) that will take place in the future. Because the future contains a great deal of uncertainty, the assumption that these estimates are completely accurate is not reasonable.

Q. Do any authoritative sources support that assessment?

A. Absolutely. Again, NARUC states that:

> Instances occur where subsequent experience shows the original estimates no longer to be appropriate. It should be noted that only after plant has lived its entire useful life will the true depreciation parameters become known.[10]

[10] NARUC, p. 189.

Thus, NARUC is quite clear that estimates should not be considered completely accurate. It follows that the existence of a theoretical reserve imbalance should not be considered intergenerational inequity. Frank K. Wolf and W. Chester Fitch's *Depreciation Systems* (Wolf and Fitch) is another highly regarded, authoritative depreciation text. Wolf and Fitch also comment on the matter, stating:

> The CAD [theoretical reserve] is not a precise measurement. It is based on a model that only approximates the complex chain of events that occur in an actual property group and depends upon forecasts of future life and salvage. Thus, it serves as a guide to, not a prescription for, adjustments to the accumulated provision for depreciation.[11]

Given the complexities and uncertainties involved in estimating the future, we should not assume that the estimates in a depreciation study are completely accurate (which is an assumption inherent in Mr. Kaufman's proposal). They are the best estimates given the best information available, but we will not know for sure that they are correct until the plant has lived its entire useful life.[12] In future studies shorter lives or more negative net salvage may be appropriate, at which point a large negative theoretical reserve imbalance (or reserve deficiency) would develop if Mr. Kaufman's proposal was adopted. This would result in an even larger increase in rates (whether the

[11] *Depreciation Systems* (1994), Frank K. Wolf and W. Chester Fitch, p. 86.
[12] To put this in context, the average service life estimates in the depreciation study for many accounts are in the 50 to 60-year range. These are only averages though, and the estimates mean that some plant will last longer than 100 years. Thus, based on the service life estimates in the depreciation study, we will not know for certain if the estimates are correct for over 100 years.

remaining life technique or another reserve amortization were used). The remaining life technique provides for more stability in rates by allocating costs over the remaining lives, whereas Mr. Kaufman's approach would lead to much more volatility.

Q. Please address the second assumption inherent in Mr. Kaufman's position that prior estimates were "incorrect."

A. An understanding that the accuracy of depreciation estimates is unknown until all plant has lived its full useful life demonstrates the fallacy of the assumption that the existence of a reserve imbalance means that prior estimates were wrong and previous customers are subsidizing costs for future customers. To make such an assumption inherently assumes that today we have perfect knowledge of the future, which is an unrealistic assumption. Yet this is implicit in Mr. Kaufman's recommendation to amortize the theoretical reserve imbalance over a relatively short period of time.

Wolf and Fitch explain that the theoretical reserve is a simple model of a "complex chain of events." Many of the simplifying assumptions[13] inherent in the theoretical reserve model are not necessarily reasonable assumptions regarding actual real-world experience.

Q. What assumptions are inherent in the theoretical reserve model?

[13] The assumptions discussed here are related primarily to assumptions regarding life characteristics. However, one assumption made regarding the way net salvage is normally calculated in the theoretical reserve is that average and future net salvage are equal. This is in fact often not the case, and future net salvage is typically greater than average net salvage. The effect of this assumption is therefore normally to understate the theoretical reserve and overstate an estimated theoretical reserve "excess."

A. One key assumption is that all vintages of plant have the same life characteristics. While the depreciable groups studied in a depreciation study (based largely on the FERC USofA) are relatively homogeneous, there is variety within the accounts and not all assets, much less vintages of assets, will necessarily have the same life characteristics. For example, different materials may have been used for overhead conductors at different periods of time. If these different materials have different life characteristics, then the service life estimates will change naturally over time as the composition of types of assets in the overhead conductors account changes over time. For this reason, service life estimates today may be longer than would have been appropriate ten or twenty years ago. Because the service life estimate for the account is estimated for assets in service today, this natural change would result in a theoretical reserve imbalance due to the changing life characteristics over time. However, this does not necessarily mean that previous depreciation rates were too high, as Mr. Kaufman implies. Instead, it simply means that the life characteristics for the account are dynamic and have changed over time. In other words, given that different vintages of plant can have different life characteristics, it is incorrect to assume that the life estimates made today should have applied in the past for the entire history of the Company. Yet this is an assumption of the theoretical reserve model and an assumption Mr. Kaufman makes in his recommendation for the theoretical reserve imbalance.

Q. Are there other assumptions inherent to the theoretical reserve model?

A. Yes. Another assumption is that life characteristics do not change over time. We have explained that different vintages of plant can have different life characteristics. However, the life characteristics themselves can change over time as well. For example, operational practices, maintenance practices, and management decisions can change life characteristics over time. A good example is meters. An estimate that meters would last for 30 years was a reasonable estimate three or four decades ago. However, experience has shown that this was not a reasonable assumption ten years ago. The assets themselves did not change - the electromechanical meters 30 years ago were similar to those in service ten years ago - and the physical characteristics of these meters did not change. However, other considerations such as functionality or technology did change, which resulted in a significant change in life characteristics. This example illustrates that life characteristics do change over time and the theoretical reserve is far too simplistic an assumption from which to draw the conclusion that previous depreciation rates resulted in an overpayment.

Q. Do you have further comments related to the claim that previous depreciation rates were too high?

A. Yes. The Company's historical depreciation rates have been based on periodic depreciation studies in which the Company has presented what it considers to be the best estimates of depreciation based on the information available at the time. Other parties have also had the opportunity to present their estimates based on the same information. The Commission has concluded that the depreciation rates used by the Company were reasonable based on the information available at the time. That is, the book reserve for PGE is based on the depreciation rates that the Commission has historically recognized to be just and reasonable.

III. SERVICE LIFE ESTIMATES

Q. Does Mr. Kaufman propose changes to the service lives determined in the Stipulation?

A. Yes. He proposes changes to the survivor curve estimates for the accounts shown in the table below. The Stipulating Parties note that, with the exception of Accounts 352 and 356, these are interim survivor curve estimates, and the overall service life is also determined based on an estimated retirement date. Except for the Sullivan hydro plant, Mr. Kaufman has not recommended changes to the retirement dates for production facilities.

ACCOUNT	STIPULATION ESTIMATE	AWEC PROPOSED ESTIMATE
311	90-S1.5	98-R3
332	105-R3	120-R3
341	70-R3	80-R3
341.01	40-R4	50-S3
344.01	30-R3	38-R4
345	50-R2.5	60-R3
345.01	30-S2.5	45-S2
352	70-R2.5	75-R2.5
356	65-R2.5	70-R2.5

September 28, 2021

To: Curtis Dlouhy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 749
Dated September 14, 2021

Request:

Please provide a narrative description of the purpose of the Trojan Nuclear Decommissioning Trust (NDT).

Response:

PGE is required to provide financial assurance for decommissioning obligations for a nuclear generating unit, consistent with federal Nuclear Regulatory Commission (NRC) requirements. As allowed by 10 CFR 72.30(e)(5), PGE provides ISFSI radiological decommissioning funding assurance using the method provided in 10 CFR 50.75(e)(1)(ii). Specifically, PGE has established and maintains an external sinking fund in the form of a trust, which is segregated from PGE's assets and outside PGE's administrative control, and into which funds are set aside such that the total amount of funds will be sufficient to pay radiological decommissioning costs.

September 28, 2021

To: Curtis Dlouhy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 752
Dated September 14, 2021

Request:

Please provide a narrative description of the types of assets held in the trust.

Response:

The asset allocation of the Trojan Nuclear Decommissioning Trust (NDT) Qualified and Non-Qualified NDT plans consists of 100% Fixed income. Within the fixed income there are Corporates, Government, Mortgage-Backed securities, Collateralized Mortgage Obligations, Municipal bonds, and Cash.

PGE's response to AWEC Data Request No. 091, Attachments 091-A and 091-B, provides the Trojan (NDT) non-qualified and qualified outstanding securities as of December 31, 2020. The asset summary included in each of these documents provides the types of assets and what percent of the portfolio they represent.

Please note that the reports provided in PGE's response to AWEC Data Request No. 091, Attachments 091-A and 091-B, do not include qualified and non-qualified cash assets of approximately $5.5 million and $6.2 million, respectively. The cash assets are invested in a Money Market Fund at Northern Trust.

CASE: UE 394
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Exhibits in Support
of
Opening Testimony

October 25, 2021

STAFF EXHIBIT 503

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 21-206

August 27, 2021

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE *Revised* Response to OPUC Standard Data Request 057
Dated March 10, 2015

Request:

Please provide transaction summaries for Non-Labor costs recorded in all FERC Accounts for the Base Year. Please place in MS Excel and for each transaction include:

a. Total amount charged, and as applicable, any subtotals assigned to Non-Utility/Total Company Allocation and/or OR-Allocation;
b. Description of cost;
c. Name of vendor (if applicable);
d. Business Unit (Profit Center) being charged;
f. Service provided (e.g., reports to stockholders, lease, etc.).

Original Response (Dated July 19, 2021):

Attachment 057-A provides the requested transaction listings for 2020.

Attachment 057-A contains protected information and is subject to General Protective Order 21-206.

Revised Response (Dated August 27, 2021):

Attachment 057-B provides the requested data, revised to exclude cost elements 1502 (non-PGE straight-time labor) and 1602 (non-PGE overtime labor) and include cost element 5599 (non-labor allocations). Additionally, Attachment 057-B removes all costs related to PGE's August 2020 trading losses. Finally, Attachment 057-B corrects the calculation performed to derive PGE's share of co-owned facilities.

Attachment 057-B contains protected information and is subject to Protective Order 21-206.

PGE's Confidential Response to Staff Standard Data Request 057, Attach B CONF

Is

Filed in electronic format

PGE's Confidential Response to Staff Standard Data Request 057, Attach B CONF

Staff filters (no description/no vendor entries)

Is

Filed in electronic format

PGE's Confidential Response to Staff Standard Data Request 057, Attach B CONF

Staff filter (description "gross earnings")

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Filed in electronic format

PGE’s Confidential Response to Staff Standard Data Request 057, Attach B CONF

Staff filter (description “LL – post retirement service cost”)

Is

Filed in electronic format

July 19, 2021

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Standard Data Request 064
Dated March 10, 2015

Request:

For each Medical (Health, Dental, and Vision) plan, please identify the premium for the Test Year, Base Year, and two calendar years prior to the Base Year. If the premium amounts vary by labor group, please provide the information for each labor group separately.

Response:

Attachment 064-A provides a summary of premium amounts for health, dental, and vision plans for 2018, 2019, 2020, and forecasted 2022. Please note, Willis Towers Watson actuarially derives PGE's retiree medical plan cost estimates for the test year; therefore, PGE does not request premium estimates for these plans as they are not needed to develop the test year forecast.

For additional information on the assumptions used for retiree medical and other health benefit forecasts, see PGE's response to OPUC Data Request No. 063.

Attachment 064-A contains protected information and is subject to General Protective Order No. 21-206.

PGE's Confidential Response to Staff Standard Data Request 064, Attach A CONF

Is

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August 30, 2021

To: Michelle Scala
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 461
Dated August 16, 2021

Request:

Does the Test Year include projections for new IT projects, IT system upgrades, and/or incremental IT rate base additions? If yes, please provide:

a. A breakout of expenditures by project, to include the total Company dollar amount, and the FERC account.
b. A brief narrative describing why each project is needed and how ratepayers will benefit.

Response:

Attachment 461-A provides the requested information.

Attachment 461-A contains protected information and is subject to General Protective Order No. 21-206.

PGE's Confidential Response to Staff Data Request 461, Attach A CONF

Is

Filed in electronic format

September 28, 2021

To: Curtis Dlouhy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 754
Dated September 14, 2021

Request:

Refer to PGE/200, Tooman – Batzler/16 at line 20:

a. Please describe the analysis done on the annual accrual of the Trojan (NDT).
b. If the Company generated or received a formal analysis write-up or report, please include these materials in your response.

Response:

a. Attachment 754-A provides the Trojan NDT model used to estimate the Trojan Annual Accrual.
Tab "Model Update Actions" provides the list of the updates performed on the Trojan NDT model to determine the annual accrual. Specifically, PGE used (1) the most current projections of expected annual Trojan nuclear decommissioning costs (see tab "Cost Projections"), (2) inflation and interest rates projections for different types of investment instruments, and the 2020 end of year trust balances (see tab "Financial Assumptions") to determine the required annual accrual that ensures PGE will have sufficient funds to pay for the Trojan radiological decommissioning costs.
Tab "Return – 2022 GRC" summarizes the investment return assumptions (See Financial Tables 1, 2, and 3), the trust activities (see Tables 4 through 14), and the accrual and projected cash flow (see Tables 15 and 16).
b. PGE objects to this request on the basis that it is vague. Without waiving and notwithstanding this objection, PGE responds as follows:
PGE did not receive or generate a formal analysis report to determine the Trojan NDT annual accrual other than the model provided as Attachment 754-A. This model is updated as part of every general rate case to evaluate the Trojan NDT annual accrual required to ensure PGE will have sufficient funds to pay for the Trojan decommissioning costs, as required by the Nuclear Regulatory Commission.

Attachment 754-A is protected information subject to Protective Order No. 21-206.

PGE's Confidential Response to Staff Data Request 754, Attach A CONF

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Filed in electronic format

Pages 13 and 14 are confidential and

is subject to

Protective Order No. 21-206

f. Computing devices have a 3-year warranty. If devices fail after their warranty period is up, but before they have reached their 4- or 5-year cycle, we simply retire that asset. The increases in processor speeds and overall power of laptops and desktops have slowed over the last several years. We have also found that the weight of laptops is now staying approximately the same. Due to this, we are replacing based on expected failure rate more than on technology improvements. We also find that computers become difficult to manage and keep secure when they exceed the 4- or 5-year cycle. Security updates may not be available for older hardware and the overall costs of supporting many different generations of computers becomes expensive.

PGE's Confidential Response to Staff Data Request 791, Attach A CONF

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Page 17 is confidential and is

subject to

Protective Order No. 21-206

Pages 18 through pages 23 are confidential and

is subject to

Protective Order No. 21-206

STAFF EXHIBIT 503

IS CONFIDENTIAL AND SUBJECT TO

MODIFIED PROTECTIVE ORDER NO. 21-237

August 30, 2021

To: Brian Fjeldheim
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 453
Dated August 16, 2021

Request:

In the past five years, has the Company:

a) Suffered a data breach? If yes, please provide a narrative of the breach, the monetary impact to the Company, and the number of customers affected.

b) Suffered any damage to digital or physical systems due to an external cyber intrusion? If yes, please provide a narrative description for each occurrence, to include steps taken to mitigate the damage and prevent future attacks.

c) Received notification from NERC of a critical infrastructure protection (CIP) plan violation related to cybersecurity? If yes, please provide.
   i. The date of each infraction,
   ii. A description of the violation,
   iii. A description of the action taken against the Company (e.g. fine, sanction), and
   iv. The dollar amount for each fine or sanction (if any).

Response:

a. PGE has not suffered a data breach in the last five years.

b. PGE has not suffered any damage due to an external cyber intrusion in the last five years.

c. In the last five years, PGE has not received notification from NERC of any CIP violations related to cybersecurity. PGE has self-reported potential violations to WECC during this time period. Please see confidential Attachment 453-A for detailed information about potential violations that WECC has formally acted on since January 1, 2017.

Attachment 453-A contains protected information and is subject to Modified Protective Order No. 21-237.

PGE's Confidential Response to Staff Data Request 453, Attach A CONF

Is

Filed in electronic format

CASE: UE 394
WITNESSES: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

REDACTED

Opening Testimony

October 25, 2021

Q. Please each state your name and occupation.

A. My name is Curtis Dlouhy. I am a Senior Economist within the Rates, Finance and Audit (RFA) Division of the Public Utility Commission of Oregon (Commission or OPUC).

Q. What is your common business address?

A. 201 High Street SE, Suite 100, Salem, OR 97301.

Q. Describe your educational background and work experience.

A. My educational background and work experience are set forth in my Witness Qualification Statement, provided as Exhibit Staff/601.

Q. What is the purpose of this testimony?

A. I am responsible for the analysis of the following items:

1. Pension and Post-Retirement Medical Expense;
2. Finance and Accounting Expense;
3. Wildfire Mitigation and Vegetation Management;
4. Enterprise Risk Management (ERM), and August 2020 Trading Losses;
5. Monetary Trading Losses Taken Out of Rates;
6. Personnel Changes Following the Trading Losses; and
7. Risk Practice Changes Following the Trading Losses.

Q. Have you issued data requests (DRs) in this rate case?

A. Yes. I issued Data Requests 122-139, 238-252, 518-526, 594-601, 639-644, 749-755, 839-840, 866-868, and 895-900 as part of my investigation into the seven issues outlined above.

Q. How is your testimony organized?

A. I organize my testimony as follows:

ISSUE 1 – PENSIONS AND POST-RETIREMENT MEDICAL BENEFITS

Q. Please summarize the Company's position on Pensions and Post-Retirement Medical Benefits?

A. Since 1987, employers are required to use Financial Accounting Standard (FAS) 87 for financial reporting of pension expenses and FAS 106 for financial reporting of post-retirement medical expenses. FAS 87 and FAS 106 require employers to recognize the cost of their pension and post-retirement medical plans on an accrual rather than a cash basis. In other words, pension and post-retirement medical expenses are recognized over the period during which benefits are earned, or "accrued" — that is, during the working years of the employees that will receive the pension benefits during retirement.

Because FAS 87 expense is based on an accrual, not cash basis, the amount of pension costs recorded is generally different than the actual amount of annual contributions made. Over the life of the plan, however, total contributions are expected to equal total FAS 87 expense (as well as FAS 88 expense related to pension plan termination).

The FAS 87 expense, which can be positive or negative, is calculated based on four components:

- Service cost
- Interest cost
- Expected return on assets (EROA)
- Discount rate

Increases to the service cost and interest cost ultimately raise overall pension or post-retirement medical expenses. The EROA and the discount rate are percentages that broadly reflect market conditions and how the trust will perform in the market. I will discuss both the EROA and discount rate in greater detail later in my testimony.

The FAS 87 and FAS 106 expense can be positive or negative. In both the FAS 87 and FAS 106, a negative expense means that the trust is in good financial health and is self-sustaining. Likewise, a positive expense means that funds are being drawn from the account faster than they are being recovered, meaning that additional contributions are needed to maintain the trust.

Q. Please summarize the Company's proposal for Pensions and Post-Retirement Medical Benefits.

A. The Company forecasts its pension cost to be $19.6 million, or approximately $11.9 million after capitalization.[1] This value is slightly below its 2020 actuals.[2] PGE forecasts 2022 costs for post-retirement medical benefits, its Health Reimbursement Arrangement (HRA) for retirees, will be $2.3 million. This value is approximately $350,000 above its 2020 actuals.[3]

Q. Please discuss the cost drivers of the pension expenses over which the Company can exercise its discretion.

A. While there are many parameters that go into calculating the full expense of a pension plan, there are two that require the Company to make a judgment calls based on anticipated market conditions – the assumed EROA and the discount rate.

Q. Please briefly discuss what the EROA is and how it influences the overall pension expense.

A. The EROA is the expected rate of return on assets used to fund a pension plan or a post-retirement benefits plan in nominal terms. A higher EROA represents that a plan is expected to generate more money from its assets, which ultimately translates directly into lower benefit obligation cost or higher income.

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1 PGE/300, Mersereau – Neitzke/34.
2 PGE/300, Mersereau – Neitzke/34.
3 Staff/605, Dlouhy/10.

It is true that the investments required for a higher EROA are riskier than for a lower EROA. However, the source of funding for pensions comes from two sources: investments and PGE, and its ratepayers. If a very conservative investment approach is used with low risk, such as Treasury securities, then ratepayers must pay for capital infusions to meet pension obligations. A more aggressive investment approach allows for the "market" to more fully fund pension obligations.

Q. Please briefly discuss what the discount rate is and how it influences the overall pension expense.

A. The discount rate is the expected market interest rate for the relevant asset or portfolio of assets by which to discount future pension obligations. It is one component that is used to calculate the present value of a portfolio that provides a stream of revenue. An increase in the discount rate decreases the present value of the projected future pension obligations.

Q. How has the Commission treated the selection of the discount rate when calculating Pensions and Post-Retirement Medical Expenses in past dockets?

A. In UE 335, the Commission adopted an all-parties stipulation using the two-week average of the discount rate provided by Willis Tower Watson on August, 31, 2018.[4] At the time of the filing of UE 335 in February 2018, the Company asked for a 3.64 percent discount rate.[5] Staff was supportive of

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4 Order No. 19-129 at page 9.
5 Staff/603, Dlouhy/1-2.

an update to the discount rate on the grounds that interest rates were likely to rise, which would lower pension liabilities. Staff cites these facts from a historical perspective and not to establish reasonable values for this docket.

Q. What EROA and discount rate did PGE use to calculate its pension expense.

A. PGE used a discount rate of 2.7 percent and an EORA of 7.0 percent.[6] For the sake of clarity, it is worth noting that the Company incorrectly stated that it used a 2.53 percent discount rate in its Opening Testimony but corrected this in its response to Staff DR No. 640.[7]

Q. Can you summarize your overall recommendation on the issue of Pensions and Post-Retirement Medical Benefits?

A. After comparing the Company's actual ROA with the plan's EROA for the last four years, I recommend increasing the Company's projected EROA by 40 basis points in order to make it better match the Company's actual ROA over the last four years while still keeping it in the range of EROAs used by other Oregon-regulated utilities. This results in a reduction of forecasted annual pension expenses of $2.6 million.

I perform the same analysis with the Company's post-retirement medical expenses and find that the EROA used for post-retirement medical expenses is much more in line with its actual. The Company uses a

6 PGE/300, Mersereau – Neitzke/34.
7 Staff/602, Dlouhy/16.

combination of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** discount rate and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for its EROA for various post-retirement medical expense plans.[8] Taking the geometric mean of the last four years of the Company's actual ROA yields an average actual ROA of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In the case of the post-retirement medical benefits expenses, the actual ROA and the EROA are sufficiently in line with the combination of discount rates that the Company uses that I recommend no adjustment.

Although the Company's proposed drop in its discount rate is large, I find it to be well-substantiated by the Company's report form Willis Tower Watson and to match overall trends in the market. I recommend no change on this item for either its pension or post-retirement medical benefits expenses.

Q. How does your recommended changes to the EROA compare to values used by other Oregon-regulated utilities?

A. In Table 1 I provide a breakdown of the discount rates and EROA used by other Oregon-regulated utilities according to each Company's most recent SEC 10-K filing. As you can see, the Company's proposed EROA of 7.0 percent is the third highest EROA used by any Oregon-regulated utility, behind only Northwest Natural and Idaho Power. My recommended change to the EROA would give PGE a 7.40 percent ROE which would tie

[8] Staff/605, Dlouhy/9.

it with Idaho Power. PGE uses the lowest discount rate of any Oregon regulated utility as evidenced in Table 1 below.

Table 1. Comparison of Pension Plan Parameters

Company	Utility Type	Discount Rate	EROA
Cascade*	Gas	2.96%	6.25%
Avista	Gas	3.85%	5.50%
Northwest Natural	Gas	3.18%	7.25%
PacifiCorp	Electric	3.32%	5.94%
Portland General	Electric	2.70%	7.00%
Idaho Power	Electric	3.60%	7.40%
	Min	2.70%	5.50%
	Max	3.85%	7.40%

*Note: MDU's 10k used in place of Cascade Natural Gas

Q. Why do you think it is proper to increase the EROA to match the highest EROA by any Oregon-regulated utility?

A. In order to determine if a change to the Company's EROA was warranted, I examined the Company's actual ROA for the last four years using the Company's response to SDR 59. I found that the geometric mean of the Company's actual ROA was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, which is substantially higher than the EROA used in the Company's pension expense calculations.

Q. You point out earlier that Staff previously found that the Company's 7.0 percent EROA was reasonable in past rate cases. Why should the Commission re-evaluate that now?

A. The COVID-19 pandemic decreased GDP significantly and the rebound of the pandemic is expected to give rise to future high growth returns and is expected to be sustained well into the future. Additionally, Staff assigned to analyze pensions in UE 335, which was prior to the pandemic, also noted that a 7.0 percent EROA seemed conservative at the time.[9]

Q. Although the Company has earned a much higher actual ROA in the past, why do you believe that this trend is slated to continue in the future?

A. In Exhibit 604, I include a sample of financial news relevant to market returns.[10] It is widely believed that inflation is expected to remain above two percent for the foreseeable future, contributing to higher nominal returns. Further, the economy is bouncing back strongly post-COVID-19 pandemic even in the wake of the emerging delta variant, thus raising the expected real component of returns as well. Therefore, between the Company's historic overearning with respect to its EROA and the expectation that returns will stay high given inflationary pressures and a resurging economy

Q. What analysis have you done to examine the Company's discount rate?

A. As noted in the previous table, PGE assumes the lowest discount rate of any Oregon-regulated utility. To determine whether the Company's discount rate is appropriate, I analyzed two things:

1. Yields on Corporate AA bonds since the Company last updated its discount rate.

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9 Staff/603, Dlouhy/1.
10 Staff/604.

2. The portfolio of bonds held by the Company and its implied discount rate.

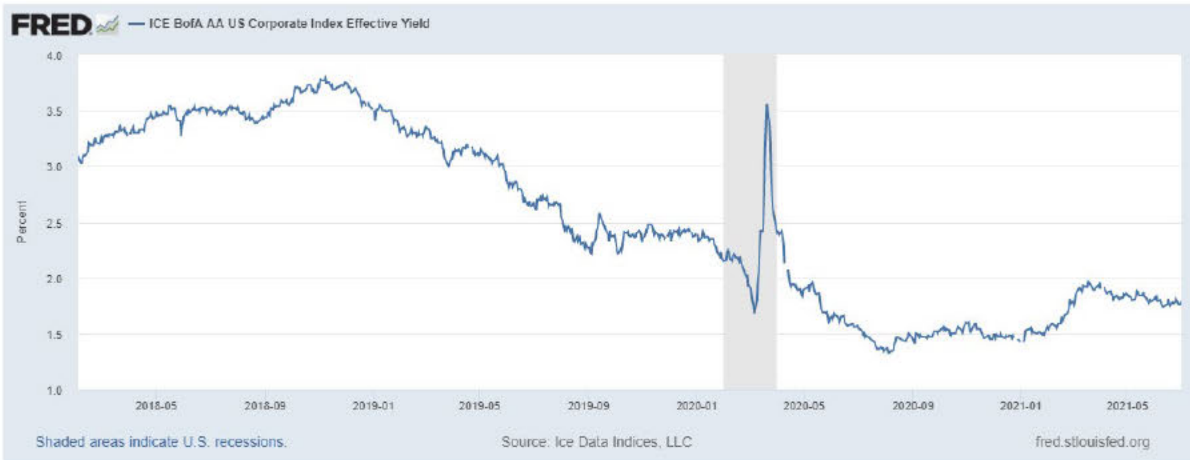
Q. How can Corporate AA-rated bond yields be used to determine the appropriateness of a discount rate?

A. As stated earlier in this testimony, the discount rate is the expected market interest rate by which to present value future obligations. The discount rate is the return for low-risk assets. The discount rate changes as market interest rates change. PGE’s pension plan portfolio relies in part on AA-rated Corporate bonds, so changes to yields of Corporate AA-rated bonds can be used to check the reasonableness of changes to the Company’s discount rate.

Q. How has the average yield on AA-rated bonds changed since PGE’s last rate case and how does this compare to the change in the Company’s discount rate?

A. As stated earlier, PGE’s initial filing of UE 335 in February 2018 assumed a 3.64 percent discount rate compared to the UE 2.70 percent discount rate in the initial filing of UE 394 in July 2021. This constitutes a drop of 94 basis points. From February 2018 to July 2021, the average interest rate of an AA-rated corporate bond dropped from 3.08 percent to 1.78 percent, which is a drop in 130 basis points. This can be seen in Figure 1 where I show the change in Corporate AA-rated bond yields as compiled by the St. Louis FRED.

Figure 1. Corporate AA-rated Bond Yields



PGE's decision to reduce its discount rate from that proposed in UE 335 is supported by market changes in interest rates.

Q. Are there other sources of information to corroborate the Company's choice in discount rate?

A. Yes. In response to CUB DR 16, the Company provided analysis done by Willis Tower Watson from December 31, 2020, using a theoretical bond portfolio.[11] At the time of the analysis, Willis Tower Watson recommended a discount rate of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[12]

The change in discount rates between the value provided by Willis Tower Watson and that used in PGE's opening testimony is negligible and appears to match the upward trend in yields observed in the first six months of 2021 in Figure 1. Further, the "Willis Tower Watson" tool has been used

[11] Staff/602, Dlouhy/1.
[12] Staff/605, Dlouhy/1.

to update the Company's discount rate in past rate cases.[13] Therefore, I have no adjustment to PGE's discount rate of 2.70 percent.

Q. What is your recommended adjustment after your recommended changes to the discount rate and EROA?

A. As stated earlier, my only recommended change is to raise the Company's EROA used for pension expenses by 40 basis points to 7.40 percent. I note that this adjustment is far smaller than the observed difference between the Company's actual ROA and EROA for the last 4 years but keeps the Company's EROA in line with other Oregon-regulated utilities. This results in a decrease of pension expense by approximately $2.6 million with respect to the Company's initial filing.

Q. Please explain how you calculate your adjustment.

A. I calculate my adjustment by modifying the Company's Confidential Attachment B to SDR 59, which shows how it calculates its final pension expense. One component to calculate the dollar value of its pension expense the EROA, which the Company assumes to be 7.0 percent. I multiply this value by 7.40/7.0 to make it instead represent the dollar value of a 7.40 percent EROA and carry all other calculations through to arrive at my recommended final pension expense. This results in an overall pension expense of $17.0 million and a downward adjustment to PGE's proposed pension expense by approximately $2.6 million.

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[13] Order No. 18-464 at page 9.

Q. What is your overall adjustment to Pensions and Post-Retirement Medical Expenses?

A. My overall adjustment is to lower Pensions and Post-Retirement Medical Expenses by $2.6 million. This is driven entirely by increasing the EROA for the Company's pension plan.

ISSUE 2 – FINANCE AND ACCOUNTING EXPENSES

Q. Please summarize the Company's position on Finance and Accounting Expenses?

A. The Company proposes to increase its Finance and Accounting expenses from $10.3 million to $12.1 million. This is largely due to internal reorganization and the reinstitution of five of the seven positions that were frozen due to the COVID-19 pandemic.[14] The Company notes that some costs are due to inflationary increases that were previously paused.[15]

Q. Can you summarize your overall recommendation on the issue of Finance and Accounting Expenses?

A. I have no adjustment to PGE's Test Year expense for finance and accounting.

Q. What analysis did you perform to arrive at the conclusion that no adjustment to the Company's finance and accounting expenses is necessary?

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[14] PGE/400, Ajello – Batzler/17-18.
[15] PGE/400, Ajello – Batzler/19.

A. I performed the following analysis to arrive at this conclusion:

- I analyzed the work papers that PGE included to calculate its finance and accounting expenses to ensure that the work papers match the costs proposed by the Company in its opening testimony and that there were no onerous cost items. I find that the only difference between the costs can be attributed to a rounding error and that all the cost items included in the work papers are justified.
- I analyzed the positions that were added back after the resumption of more normal business practices post-COVID-19 lockdown. I found that the positions are necessary.[16]
- I was initially concerned that the reorganization may be attributed to the Company's August 2020 trading losses and asked whether there was indeed any relation. I found that the reorganization was indeed not related to the Trading Losses.[17]

ISSUE 3 – WILDFIRE MITIGATION AND VEGETATION MANAGEMENT

Q. Please summarize the Company's proposals for cost recovery for Wildfire Mitigation and Vegetation Management (WMVM)?

A. The Company proposes the following:

16 Staff/602, Dlouhy/12.
17 Staff/602, Dlouhy/13.

- Include $6.6 million for Wildfire Mitigation in the Test year as O&M expenses. This is an increase of $4.6 million over 2020 actuals.[18] It represents a percentage increase in spending of 230 percent.
- Include $6.0 million in rate base for Wildfire Mitigation capital projects that will be put into place before April 30, 2022.[19]
- Include $48.7 million of Vegetation Management O&M expense in the 2022 Test Year. This in an increase of $22.6 million over 2020 actuals.[20] It represents a percentage increase in spending of 87 percent.

The total O&M WMVM expenses the Company requests is approximately $55.3 million.

Q. How has the Commission treated WMVM issues?

A. Leading up to and directly following the 2020 Labor Day wildfires, the Commission's interest in utility activities to address wildfire risk has amplified. This can be seen in a plethora of Commission activities ranging from extensive rulemaking in AR 638 and AR 648 to the approval of deferral dockets for recovery of costs associated with the 2020 Labor Day wildfires.

Of particular interest to this docket, the Commission adopted a performance-based rate mechanism for PacifiCorp's WMVM expenses as

18 PGE/800, Bekkedahl – Jenkins/53.
19 *Ibid.*
20 PGE/800, Bekkedahl – Jenkins/54.

part of PacifiCorp's general rate case, UE 374.[21] The point of this mechanism is to support and tie PacifiCorp's cost recovery of vegetation and wildfire management practices to PacifiCorp's performance in managing vegetation management with focus on high consequence fire areas.

Q. What are the main cost drivers for Wildfire Mitigation O&M expenses?

A. The main cost driver for the increase in the Company's wildfire mitigation O&M expenses is the addition of ten new positions and the transfer of one position from another division.[22]

Q. What are the main cost drivers for the Company's Wildfire Mitigation capital projects?

A. The main cost drivers for Wildfire Mitigation capital costs are replacing poles and cross arms with more fire-resistant versions and adding viper reclosers to equipment.[23]

Q. What are the main cost drivers for Vegetation Management O&M expenses?

A. The main cost drivers for Vegetation Management O&M expenses are updates to line-clearing programs, the Company's new Enhanced Vegetation Management (EVM) program, and the Company's new Advanced Wildfire Risk Reduction (AWRR) program.[24]

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21 Order 20-473.
22 PGE/800, Bekkedahl – Jenkins/50.
23 PGE/800, Bekkedahl – Jenkins/50.
24 PGE/800, Bekkedahl – Jenkins/55.

Q. What is your overall recommendation and adjustment on the topic of WMVM?

A. I find no issues with any part of the Company's overall proposed WMVW capital or O&M expenses. However, I do recommend withholding $3 million from the Company's overall WMVM budget and establishing a deferral account in which the Company may place up to $6 million in incremental costs or any decremental costs that differ from the costs included in base rates. Any deferred costs would be subject to a subsequent prudence review and amortization. The amount of prudently incurred costs subject to amortization would be based on the number of vegetation management violations identified by Commission safety inspections and its impact on earnings thresholds. Further, any costs that go into wildfire or Level-III outage deferrals would not go towards this new deferral.

Q. Why do you recommend the Commission adopt a performance-based mechanism for PGE regarding Vegetation Management and WMVW expenses?

A. As climate change accelerates, the risk of wildfires may become even more prevalent, particularly large fires, especially when looking at long time frames. I have provided below Tables 2 and 3. In Table 2, eight of the ten biggest fires have occurred in the last 20 years, and seven of the ten have occurred in the last ten years, although a few were in the beginning of the ten-year period. While there may not be a clear pattern over the last ten years themselves, when looked at over a much longer time frame there does appear to be more frequent significant fires.[25]

Further, the total number of acres burned in the United States as a whole is trending upwards every year as can be seen in Table 3. With that, the public has recognized that more resources should be put towards activities that lower wildfire risk and manage vegetation around energized equipment, as well as forestry management. At the same time, it is still imperative to ensure that the money going towards WMVM activities is being used properly.

[25] This mechanism will apply to costs incurred by the utility for vegetation and wildfire O&M expenses separate from any specific deferrals for very large cost events such as for declared state emergencies.

Table 2. Ten Largest Wildfires in Oregon History

Year	Fire Name	Acres Burned	Cause
2012	Long Draw	**557,028**	Lightning
2002	Biscuit	**500,000**	Lightning
2021	Bootleg	**400,000**	Unknown
2014	Buzzard Complex	**395,747**	Lightning
2012	Holloway	**245,308**	Lightning
1933	Tillamook Burn	**240,000**	Human
1939	2nd Tillamook Burn	**217,000**	Human
2020	Lionshead	**204,586**	Unknown
2020	Beachie Creek	**193,566**	Unknown
2017	Chetco Bar	**191,125**	Lightning

Table 3. Total Annual Acres Burned in the US

NATIONAL INTERAGENCY FIRE CENTER Boise, Idaho

Total Wildfires and Acres

The National Interagency Coordination Center at NIFC compiles annual wildland fire statistics for federal and state agencies. This information is provided through Situation Reports, which have been in use for several decades. Prior to 1983, the federal wildland fire agencies did not track official wildfire data using current reporting processes. As a result, there is no official data prior to 1983 posted on this site.

Source: National Interagency Coordination Center

Year	Fires	Acres
2020	58,950	10,122,336
2019	50,477	4,664,364
2018	58,083	8,767,492
2017	71,499	10,026,086
2016	67,743	5,509,995
2015	68,151	10,125,149
2014	63,312	3,595,613
2013	47,579	4,319,546
2012	67,774	9,326,238
2011	74,126	8,711,367
2010	71,971	3,422,724
2009	78,792	5,921,786
2008	78,979	5,292,468
2007	85,705	9,328,045
2006	96,385	9,873,745
2005	66,753	8,689,389
2004	65,461	*8,097,880
2003	63,629	3,960,842
2002	73,457	7,184,712

Year	Fires	Acres
2001	84,079	3,570,911
2000	92,250	7,393,493
1999	92,487	5,626,093
1998	81,043	1,329,704
1997	66,196	2,856,959
1996	96,363	6,065,998
1995	82,234	1,840,546
1994	79,107	4,073,579
1993	58,810	1,797,574
1992	87,394	2,069,929
1991	75,754	2,953,578
1990	66,481	4,621,621
1989	48,949	1,827,310
1988	72,750	5,009,290
1987	71,300	2,447,296
1986	85,907	2,719,162
1985	82,591	2,896,147
1984	20,493	1,148,409
1983	18,229	1,323,666

Q. What analysis have you done to analyze the Company's WMVW costs?

A. Although there is a need to ensure that the Company is taking the proper steps to address its WMVM and that increases in costs are prudent, the Company's added O&M expenses are large and there are some discrepancies in the Company's capital costs. In the case of the capital costs, I issued data requests for the Company to provide a cost breakdown of its wildfire mitigation capital costs and clear up any discrepancies between testimony and work papers. I have made sure that the Company's WMVM costs contain no overlap with ongoing deferral documents relating to the Labor Day wildfires and the February ice storms. Additionally, I asked the Company qualitative data requests about its vegetation management practices to determine whether its large increase in vegetation management expenses is justified.

Q. What are your conclusions about the Wildfire Mitigation capital costs?

A. In response to Staff DR 839, the Company issued a breakdown of its Wildfire Mitigation capital costs.[26] The cost items line up with the reasons the Company provides for the increase in Wildfire Mitigation capital.

In Staff DR 840, the Company describes that the discrepancy between its work papers and testimony is due merely to a difference in timing and rounding.[27] I am satisfied with the Company's answers to both DRs and have no adjustment.

Q. What analysis have you done to analyze the Company's WMVW costs?

A. I have reviewed the cost to add these employees to the Company's wildfire division. I found that the costs are incremental in nature and reflect the cost of the added staffing and have no adjustment. That is, I do not analyze

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[26] Staff/605, Dlouhy/32.

[27] Staff/602, Dlouhy/17.

whether these positions could be drawn from elsewhere in the Company. The issue of overall workforce levels is addressed by Staff Witness Cohen.

Q. Please describe what you have done to analyze the Company's wildfire mitigation O&M expenses?

A. I have done the following to analyze the Company's O&M expenses related to WMVW:

- Ensured that the Company separated its WMVM costs in the rate case from its cost on its Labor Day Wildfire and February winter storm deferral dockets, UM 2115 and UM 2156.
- Ensured that the Company's proposed costs align with the volume and average cost of a typical tree trimming operation.
- Asked the Company to provide the budgeted WMVM expenses for the next five years.

Q. Has the Company adequately separated the costs from UM 2115 and UM 2156 from this rate case?

A. Yes. As detailed in its responses to Staff DRs 124, 125, 136, 137, and 247, the Company has separately tracked all of its incremental costs related to the deferrals from its costs associated with the rate case and does not include any of the vegetation management costs related to the deferral when projecting its future vegetation management.[28]

[28] Staff/602, Dlouhy/2-10.

Q. What have you done to ensure that the Company's proposed costs align with the average costs of a typical tree trimming operation?

A. In Staff DR 243, I ask the Company to discuss the typical costs associated with a tree trimming operation and the amount of tree trimming it expects to do in 2022. The Company states that a typical tree trimming operation is expected to cost $6800-$7000 per line-mile and that it expects to trim approximately 4000 miles of trimming. This is responsible for approximately $28 million of the Company's total budgeted $48.7 million Vegetation Management O&M expenses. Between the increased cost of tree trimming and PGE's aggressive increases in vegetation management, I find this to be a reasonable increase.

Q. Do you have any adjustments to the Company's new AWRR and EVM programs?

A. No. As described earlier, the increased wildfire activity in the West has made it necessary to enact new plans with the tools to more directly target areas of high wildfire risk.

Q. What is your overall assessment of the WMVM costs that the Company included in this rate case?

A. I do not have any adjustments to the costs proposed in this general rate case. However, I do have a concern regarding PGE's lack of multi-year budgeting.

Q. Why are you concerned regarding a lack of multiyear budgeting?

A. Multiyear budgets would provide evidence that PGE has the intent to plan ahead to address wildfire risks as well as set aside or establish funds that PGE identifies as necessary to address wildfire risks. In response to data requests, the Company states it does not budget O&M and capital expenses related to WMVM more than one year in advance.[29]

Q. Is this lack of multiyear budgets a reason why you recommend withholding $3 million in WMVM expenses and establishing a performance-based mechanism?

A. Yes.

Q. Please describe your proposed WMVW performance-based rate design and deferral.

A. The withheld $3 million in WMVM O&M expenses, deferral and performance-based rate design is similar to the rate design approved by the Commission in PacifiCorp's most recent rate case, UE 374.[30] The deferral would include an annual filing that is reviewed by Staff with similar timelines to PacifiCorp's Wildfire Mitigation and Vegetation Management Cost Recovery Mechanism.

[29] Staff/602, Dlouhy/9.
[30] Order No. 20-473.

Q. Why are you recommending that $3 million be withheld from the Company's proposed WMVM O&M expenses.

A. The withheld $3 million in WMVM O&M expenses is done to incentivize the Company to improve its vegetation management practices. The amount is roughly the same amount that the Commission chose to withhold in UE 374.[31]

Q. Please describe the costs that would be included in the deferral associated with the Company's WMVM expenses.

A. The Company would include the first $6 million in incremental costs over and above the expense level in a deferral account, which is approximately the amount that PacifiCorp is allowed to recover subject to its equivalent WMVM performance-based rate mechanism approved in Order No. 20-473.[32] Further, if the Company's WMVM O&M expenses are below the amount in rate base, this negative amount is also put into the deferral to be returned to customers. The costs include expenses associated with Vegetation Management and Wildfire Prevention Measures, as well as expenses associated with recovery on new capital investments and the return on such investments. There would be a prudence review of these expenses as well as an earnings test. The earnings threshold varies based on the number of vegetation management violations identified by the Commission and the number of violations that include climbable trees.

[31] Order No. 20-473 at page 121.
[32] *Ibid.*

Incremental costs beyond the first $6 million would be subject to an earnings test described later.

Q. Please provide an example of the WMVM Performance-Based Rate Mechanism for a typical filing year.

A. In a typical year, the timeline for Staff's proposed WMVM Performance Based Rate Mechanism is described below and mimics the structure adopted for PacifiCorp in Order No 20-473.[33] Using the example of incremental costs incurred in 2022, the timeline would be as follows:

1. May 5, 2023: The Company submits a filing identifying:
   - All incremental WMVM O&M expenses or expenses below that vary from base rates from January 1, 2022 through December 31, 2022.
   - Revenue requirement for incremental WMVM capital projects put into service from January 1, 2022 through December 31, 2022.
2. September through October: The performance metrics will be applied using the results of Safety Staff's audit.
3. November 5, 2023: Any rate adjustment goes into effect.

[33] See Order No. 20-473 at page 122.

Q. How long do you recommend that the Company keep the deferral for incremental WMVM expenses active?

A. Much like what was approved in Order No. 20-473, I recommend that the Company keep the deferral and the associated performance-based rate mechanism active for a period of three years running 2022-2024. In its May 5, 2024 filing, I recommend that the Company demonstrate that the deferral has been effective and that its continued use is warranted.

Q. Please discuss the earnings review thresholds regarding your performance-based mechanism proposal.

A. Table 4 provides a listing of basis point reductions from the Commission-authorized return on equity that would apply to any earnings review for the first $6 million in incremental WMVM O&M expenses subject to this proposed mechanism. The levels are based on the annual number of vegetation management violations identified by the PUC's safety Staff.

Table 4. Proposed WMVM Performance-Based Rate Criteria

Violations Level	Threshold	Penalty
Level I	>150 violations	100 bps reduction
Level II	>300 violations	150 bps reduction
Level III	>500 violations	200 bps reduction

- *Additional 50 bps reduction in recovery if a violation occurs in a Tier 2 or Tier 3 area.*
- *Additional 50 bps reduction if PGE does not address climbable tree violations in fewer than 30 days.*

If the Company has fewer than 150 violations in a given year, it could recover prudently incurred costs up to its authorized ROE. If the Commission Safety Staff identifies between 151 and 300 violations, then PGE could recover prudently incurred costs up to its Commission authorized ROE minus 100 basis points. If the Commission Safety Staff identifies between 301 and 500 violations, then PGE could recover prudently incurred costs up to its Commission authorized ROE minus 150 basis points. If the Commission Safety Staff identifies more than 500 violations, then PGE could recover prudently incurred costs up to its Commission authorized ROE minus 200 basis points. I also recommend the performance-based mechanism include a focus on high fire consequence areas. Therefore, the Company will receive an additional 50 basis point reduction to its earnings test threshold if a violation occurs within its high-risk areas, which the Company calls its Tier 2 and Tier 3 areas.

As is consistent with Order No. 20-473 approved for PacifiCorp, any incremental WMVM beyond the first $6 million recommended by Staff will be subject to an earnings test set at the Company's ROE as authorized in this proceeding, except in the event that violations occur at or above Level II and at least one violation occurs in a Tier 2 or Tier 3 zone, in which case the earnings test would use the authorized ROE minus 50 basis points.[34]

Q. Where are the Company's Tier 2 and Tier 3 areas?

A. The Company's Tier 2 and Tier 3 areas are contained in Staff Exhibit 805 and were provided in response to Staff DR 239.

[34] Order No. 20-473 at page 122.

Q. How do these violation levels and penalties compare to the performance-based rate design proposed in UE 374?

A. The overall design is the same as that the Commission adopted in UE 374, including the amount of basis point reductions for the earnings test. However, the number of violations differs from that adopted in UE 374 to reflect differences in PGE service territory, developed based on OPUC Safety Staff field experience and analysis of past annual levels of vegetation management violations. One difference is that Staff added a further penalty if the violations that involve climbable vegetation are not addressed in a timely manner.

Q. What is climbable vegetation?

A. Climbable vegetation is defined in ORS 860-024-0016. In short, climbable vegetation constitutes any piece of vegetation with limbs low enough that a child could easily climb the vegetation and has limbs within the vegetation that the child could climb up to and touch an electrified line.

Q. Why does Staff recommend imposing an additional penalty related to climbable vegetation?

A. Climbable tree violations can pose a substantial safety risk to children in the area. I want to further incentivize the Company to address any vegetation management violations of this variety to reduce the added community danger that they impose. Accordingly, Staff recommends that if the Company does not address any identified violation for climbable trees within 30 days of receiving such notice from Staff, the earnings thresholds are reduced by an additional 50 basis points.

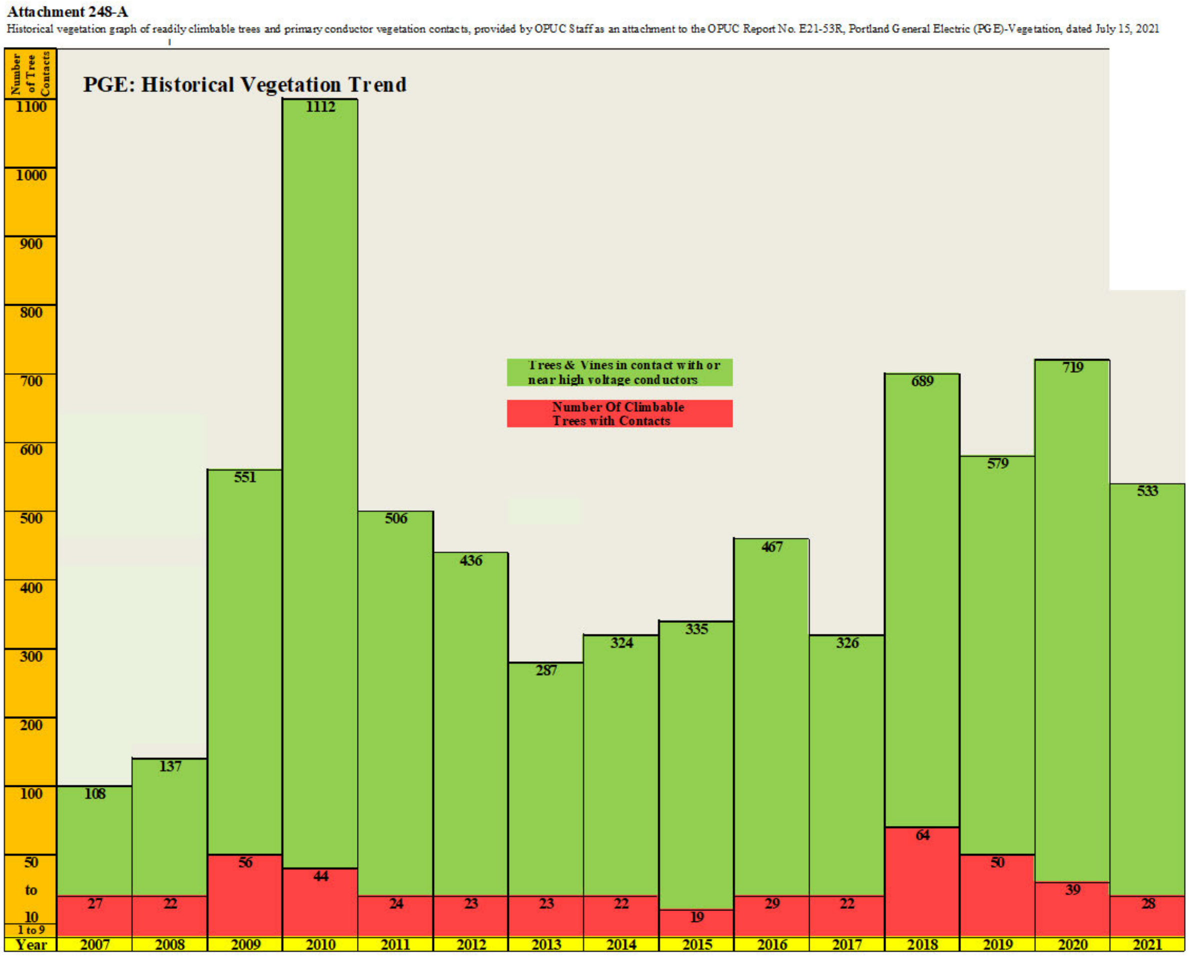
Q. Why again do the violation levels differ between your proposed performance-based rate thresholds and the thresholds used in UE 374?

A. Put simply, the thresholds differ because PGE's service territory differs from PacifiCorp in terms of wildfire risk. The thresholds were chosen in consultation with Commission Safety Staff to reflect levels that constitute a marked but attainable improvement in the Company's vegetation management violation levels based on PGE's historic violations. These improvement targets were chosen by looking at annual violations levels that Commission Safety Staff considers very good, acceptable, and not acceptable.

Q. Do you have data regarding PGE's historical level of violations?

A. Yes. In response to Staff DR 248, the Company provided its annual level of vegetation management violations from 2000 to 2020. I include this in Figure 2.

Figure 2. PGE Annual Vegetation Management Violation History



Q. Please summarize your overall adjustment to base rates.

A. I recommend taking $3 million of WMVM O&M expenses out of base rates. This brings the Company's total WMVM O&M expenses in base rates to approximately $52.3 million.

ISSUE 4 – ENTERPRISE RISK MANAGEMENT, AND AUGUST 2020 TRADING LOSSES OVERVIEW

Q. What is Enterprise Risk Management (ERM)?

A. ERM refers to the methods that a business uses to manage its risks and opportunities relative to the business's objectives. ERM can be broadly applied to anything related to the Company's operations such as its emergency preparedness protocols, public reputation, product reliability or financial performance. The details of ERM best practices are the subject of entire courses in business school, but ERM methods tend to hit on a few key things that any ERM plan should contain:

- Identification of where the Company is exposed to risk in its operations
- Quantitative measures to model risk
- Standardized practices to report risk
- Methods to audit the Company's risk assessment
- Plans of action in response to risk

Q. Has PGE cause to change its ERM recently?

A. Yes. The August 2020 Trading Losses (Trading Losses) exposed a massive oversight in the Company's ERM practices with regards to its wholesale energy market trading. This caused a massive monetary loss over a short period of time that caught the Company completely off guard.

Q. Please summarize what occurred that led to the August 2020 trading losses.

A. According to an independent review, the trading losses were caused by a combination of being caught short in the Southwest and California Trading Markets and long in the Pacific Northwest markets at the same time.[35] While holding this position, prices in the Palo Verde market exceeded $1,400 per megawatt-hour for two days in mid-August.[36] PGE's CEO Maria Pope noted that the trades that led to this exposure were being entered into with increasing volume during the second and third quarters of 2020. Pope notes that, "Simply put, these were ill conceived trades."[37]

Q. What was the total value of the losses sustained in the market?

A. The total market value of these losses was $128 million dollars; however after taxes the value of these losses are reduced.[38] These numbers only represent the direct amounts lost by the Company due to its ill-conceived trading activities.

Q. How does the Company intend to handle the August 2020 trading losses in this general rate case?

A. The Company states in its opening testimony that it intends to exclude all costs associated with the Trading Losses from its rate case.[39]

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35 Staff/604, Dlouhy/12.
36 *Ibid*
37 *Ibid.*
38 Staff/606, Dlouhy/103.
39 PGE/100, Pope – Sims/18.

Q. Did PGE exclude other costs from its 2022 Test Year that are associated with the August 2020 trading losses?

A. The following costs were identified and addressed by the Company in its opening testimony:

- A downward adjustment of Accumulated Deferred Income Taxes (ADIT) of $18.4 million to reflect the value of the production tax credits (PTCs) that would have been used had the trading losses not already reduced the Company's net income.[40]
- Costs associated with issuing $127 million in long-term debt in the fourth quarter of 2020.[41] The Company removed this debt when calculating its return on long-term debt.

Q. Has Staff identified other costs related to the 2020 Trading Losses that should be removed from the 2022 Test Year?

A. Staff has also identified the following areas that it felt the need to investigate as well:

- Proposed changes to finance and accounting costs
- Other A&G costs
- Any legal costs that may be in connection to the Trading Losses
- Focus of the Board on these issues versus focusing on other issues related to providing service to the Company's retail customers

[40] PGE/200, Tooman – Batzler/4.
[41] PGE/900, Jaramillo – Ferchland – Villadsen/2.

Q. Please describe how your testimony on the Trading Losses is organized.

A. I organize my testimony on the trading losses into three distinct sections:

1. Monetary losses taken out of rates. In this section, I analyze all items with a dollar value connected to the Trading Losses that PGE asserts have been removed from the Test Year and make sure that these are sufficiently removed from the rate case. I also discuss my analysis of other costs that were not identified by PGE to make sure that they are not related to the Trading Losses and should be excluded.
2. Personnel and organizational changes made in response to the Trading Losses. In this section, I analyze positions and committees that were removed, moved, or replaced, and changes made to reporting with respect to the Company's energy trading operations.
3. Changes in risk analysis made in response to the Trading Losses. In this section, I analyze all quantitative procedures the Company employs to manage its risk and make recommendations about things the Company could do to improve its risk evaluation.

ISSUE 5 – MONETARY TRADING LOSSES TAKEN OUT OF RATES

Q. Please describe how the Company's downward adjust of ADIT by $18.4 million ensures that ratepayers are held harmless.

A. ADIT is recorded on the balance sheet that is included in rate base that represents future taxable income. As discussed in its initial filing, PTCs are an asset that the Company uses to offset taxes on income.[42] Because the Trading Losses were put entirely on shareholders, the Company's Net Income suffered and fewer PTCs were needed to offset its earnings, leading to more remaining PTCs than there would have been had the Trading Losses not occurred.

Unless something is excluded from rate base, this excess of PTCs would lead to excessive costs included in rate base. Therefore, the Company has adjusted its ADIT included in rate base downward by $18.4 million to remove assets from rate base that it would not have removed but for the Trading Losses.

Q. Does this exclusion of $18.4 million of ADIT from rate base seem to match the scale of the trading losses?

A. Yes. In response to SDR 118, the Company provides workpapers showing its overall PTC use and separately calculates the adjustment needed to offset its added balance of PTCs. The workpaper matches the Company's adjustment in testimony and I am satisfied that the workpaper accurately calculates the amount.

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[42] PGE/200, Tooman – Batzler/4.

Q. Do you have any concerns that taking out the $18.4 from ADIT would take the benefit of the PTCs away from ratepayers?

A. Staff has not yet reached a decision on this topic and will form a decision after reviewing the testimony of interested parties in this proceeding. An argument that ratepayers have received the benefit of the PTCs is based on ORS 757.264 which states:

> Each public utility that makes sales of electricity shall forecast on an annual basis the projected state and federal production tax credits received by the public utility due to variable renewable electricity production, and the Public Utility Commission shall allow those forecasts to be included in rates through any variable power cost forecasting process established by the Commission.

Therefore, any benefits from PTCs have already been accounted for in the Company's AUT proceeding. However, it is unclear how the true-up will be carried out. If the true-up raises power costs by not considering the benefits of the PTCs, then it may be possible for ratepayers to "pay" for the PTCs and hence cover some of the costs of the trading losses.

Q. What is your assessment on the Company's move to remove the $127 million long-term bond issuances in response to the Trading Losses?

A. The effect of this PGE proposal was to increase the cost of debt and raise the cost of capital, and thus indirectly increase rates for customers higher than they would be absent this PGE proposal. As was discussed in the joint testimony in support of that stipulation, Staff did not agree with the Company's proposal to remove the fourth quarter 2020 bond issuances from the Company's long-term debt issuances.[43] Stipulating parties agreed to put it back in, which ultimately lowered the Company's overall cost of long-term debt. I recommend no further adjustment on this issue as it has already been settled, subject to Commission approval.[44]

Q. Why should the costs that PGE asserts were associated with the fourth quarter 2020 long-term bond issuances be included in the cost of long-term debt calculation?

A. The costs of the long-term debt issuances should be included for two reasons. First, it is unclear that the long-term bonds issued were in response to the Trading Losses. This is evidenced by PGE's response to highly confidential Staff DR 522.[45] From this, it does not even appear that PGE's long-term bond issuance was done in response to the Trading Losses. This is further corroborated by PGE's response to AWEC DR 53, where it can be seen in Confidential Attachment A that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** that would cover nearly all the cash needs resulting from the trading losses.[46]

43 Stipulating Parties/100, Muldoon – Gehrke – Mullins – Bieber – Chriss – Ferchland/4-5.
44 Stipulating Parties/100.
45 Staff/606, Dlouhy/106.
46 Staff/605, Dlouhy/7.

Second, the Company intends to hold ratepayers harmless from the Trading Losses but as discussed above, removing the fourth quarter debt issuance from the Company's debt portfolio actually raises the average cost of long-term debt, harming customers. Therefore, the fourth quarter 2020 debt issuances should be included if ratepayers are to be left harmless.

Once again, the Company's cost of long-term debt has been settled as part of the first stipulation and no further adjustment on this item is need.

Q. What other areas of the rate case have you looked at to ensure that the Company properly excludes all impacts of the Trading Losses?

A. All Staff were directed to analyze their issues with an eye towards identifying areas where the Trading Losses could have some cost spillovers. I have been in contact with all Staff while drafting opening testimony and drafted data requests where necessary. While most areas of the rate case appeared to be sufficiently separate from the Trading Losses, Staff has collectively identified a few areas where costs could be missed without a thorough inspection:

- Finance and Accounting Costs
- Legal and Consulting Expenses
- Other A&G
- Wages and Salaries

While Staff has not yet found any additional adjustments necessary due to the Trading Losses, Staff continues to investigate and notes that some spillovers may be rolled into other adjustments.

Q. Why might these spillovers be rolled up into other adjustments?

A. In some areas identified above, Staff has made relatively large overall adjustments that cannot be cleanly separated into separate reasons or any adjustments that can be tied back to the Trading Losses are relatively small in comparison. For example, Staff has identified a few employees that could have been incorrectly included in rate base. Ultimately, if these were included incorrectly, the cost of these employees inclusive of benefits is small relative to Staff's overall adjustment of approximately $10 million.[47] Regardless, Staff has issued data requests to try to find employees incorrectly included in rate base.

Further, some costs may be hard to identify. As an example, I state above that I expect there to be some spillover costs in the Company's A&G expenses. In Staff/500, Staff recommends removing approximately $5 million in unidentified expenses that could not be traced back to any account.[48] At this time, I expect any Trading Loss costs in A&G to already be rolled up into Staff's adjustment.

Q. Why would the Company's Finance and Accounting Expenses be affected by the Trading Losses?

A. In its opening testimony, the Company notes that it reorganized staffing in its Finance and Accounting team and increased its budget without going into detail. In my testimony on the subject, I note that I was concerned that

[47] Staff/300, Cohen/21.
[48] Staff/500, Fjeldheim/2.

some changes may be due to addressing the fallout from the Trading Losses.

Q. Do you believe that the Company's proposed adjustments to Finance and Accounting Expenses is adequately removed from the Trading Losses?

A. Yes. My analysis regarding Finance and Accounting expenses was previously discussed in my testimony. I am satisfied that the Company's proposed Finance and Accounting are well-justified and contain no spillovers from the Trading Losses.

Q. Do you believe that the Company's proposed adjustments to Finance and Accounting Expenses adequately accounts for the Trading Losses?

A. Yes. I discuss the analysis I do to Finance and Accounting expenses previously in my testimony. I am satisfied that the Company's proposed Finance and Accounting are well-justified and contain no spillovers from the Trading Losses.

Q. Has the Company separated its legal and consulting expenses associated with the Trading Losses?

A. The Company states in its response to Highly Confidential Staff DR 524 that it separately tracks its legal and consulting expenses and that none of these are reflected in any ratemaking proposals before the Commission.[49]

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[49] Staff/606, Dlouhy/103.

Q. How could the Company's wage and salary be affected by the Trading Losses?

A. Some higher-level employees ultimately left the Company in response to the Trading Losses and were not replaced. Staff wanted to ensure that these employees and the cost of their associated benefits were not included in the 2022 revenue requirement.

Q. How did you ensure that any employees let go in response to the Trading Losses were not included in the rate case?

A. Staff identified areas where employees may be incorrectly included in revenue requirement and issued data responses to ensure that there were not any FTEs or benefits improperly included. In response to these data requests, the Company notes that while some positions were eliminated, the FTE and benefits associated with those positions went to hiring for other positions.[50]

Q. Please summarize your testimony and any additional adjustments made here that are not addressed in issues not addressed by other Staff members.

A. In this section, I summarize the monetary adjustments made by the Company and Staff to ensure that ratepayers are adequately held harmless from the Trading Losses. Staff and Parties have already stipulated to add back in the debt the Company claims is associated with the Trading Losses when calculating the overall cost of long-term debt.

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[50] Staff/606, Dlouhy/105.

Staff is inclined to agree with the Company's adjustment to remove $18.4 million from ADIT to offset the unused PTCs due to the Trading Losses. However, Staff withholds judgment prior to reviewing the testimony of other parties. I and other Staff members have analyzed other areas that may have been affected by the Trading Losses and have made adjustments where necessary. In our review, we have looked for any budget abnormalities or areas where resources that were devoted to reacting to the Trading Losses were incorrectly included in the rate case.

At this time, I have no further adjustments to remove the costs associated with the Trading Losses from the rate case and note that many of my concerns are likely addressed in concurrent adjustments by other Staff. Subject to the Company's representation of the costs of the Trading Losses and the adjustments already made by other staff members, at this time I find no further issues with how the Company has held ratepayers harmless from the Trading losses.

ISSUE 6 – PERSONNEL CHANGES FOLLOWING THE TRADING LOSSES

Q. What personnel changes did the Company make immediately after the Trading Losses?

A. In the months following the Trading Losses, various employees associated with the Trading Losses left the Company. These employees were either replaced or their positions terminated.[51] The replacements ultimately remained in their new positions.

Q. What organizational actions has the Company taken to ensure that similar losses do not occur in the future?

A. PGE has made many organizational changes, such as creating a new risk committee, changing the Company's organization, eliminating and changing reporting duties of some key positions associated with the Trading Losses, adding staffing, and adding training.[52]

Q. How does the new risk committee differ from the one ?

A. The new committee differs in a two key ways from its predecessor: a different set of employees serve on the new committee, and the new committee has a more well-defined purpose and modus operandi.[53] Although some position titles have changed, the new committee members appear to replace four positions.[54]

The second way that the new committee differs from the old committee is that the new committee has a more well-defined scope and meeting norms. This can be seen in the new committee's charter. Unlike the old committee, the new committee has language to ensure that policies, programs, and processes conform with a board-approved goals.[55] This appeared to be lacking in the charter of the old committee. Further, the

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51 Staff/606, Dlouhy/1.
52 *Ibid*.
53 Staff/606, Dlouhy/51.
54 *Ibid*.
55 *Ibid*.

new committee's charter more clearly outlines the roles of each committee member and the intent of each meeting.[56]

Q. Do you believe that these two changes will help mitigate the chance of another event on the scale of the Trading Losses?

A. It appears that the new makeup of the new risk committee puts a greater emphasis on including management that deal in wholesale power purchasing and transmission. Secondly and more importantly, I believe that the clarity of the new charter is an improvement. As can be seen in the new committee's charter, the intent of each meeting is now expected to be action oriented rather than a forum to just share reports.[57] While there is no way to if this new clarity codifies what was already done under the Risk Management Committee or if it constitutes meaningful change, adding this level of clarity sets the expectation that serving on the new committee is a duty taken seriously rather than just a formality.

Q. What reasons do you have to support the proposition that moving employees around as the Company has done will change the Company's overall enterprise risk management?

A. While it is not immediately clear to me how this change improves the Company's overall enterprise risk management, I have no reason to think that it worsens the Company's enterprise risk management. Enterprise risk management can be broadly broken up into three categories:

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56 Staff/606, Dlouhy/52.

57 *Ibid*.

- Front Office – Where the Company determines energy needs, executes deals, and observes short- and long-term transaction opportunities.
- Middle Office – Where the Company employs its metrics to evaluate risk and ensures that needed expertise is in the proper areas.
- Back Office – Where the Company executes its market transactions.

Using the above definitions and the employee moves that have been made, the department appears to be a department that best fits into a Company's front office operations. However, a case could be made that it should be positioned closer to a middle office department in order to avoid the risk oversights that led to the Trading Losses. Therefore, it appears that the organizational changes made by the Company are at worst a move to a different division that is still largely front office. However, the department's new division appears to serve a more hybrid role between front and middle office than its previous one, so it may allow it to better integrate the Company's risk strategy into its market transactions.

Q. Do you believe that the elimination of the position identified by the Company could help mitigate the risk of another event of the same magnitude of the Trading Losses?

A. Although I believe that this was a good decision, I see reasons that elimination of this position could either mitigate or exacerbate potential for another event of the magnitude of the Trading Losses. On the one hand, by eliminating the position, the Company runs the risk of overburdening an employee and hindering the employee's bandwidth to make nuanced managerial decisions related to risk.

Despite this, I believe that eliminating the position was an overall improvement to the Company's risk management process by eliminating one stage of communication. By doing so, the Company may be able to minimize future communication breakdowns that could otherwise lead to unforeseen risky market positions.

Q. Do you believe that the addition of staff trainings can another event of the same magnitude of the Trading Losses?

A. Yes. All employees in these two groups will be required to periodically receive training in various topics relevant to open market transactions and ethical business practices.[58] Some of these trainings appear to directly aid employees in executing well thought out trades and other appear to simply reinforce ethical and sound business practices. Regardless of the intent of each particular section of training or whether these occurred prior to their formal inclusion, it appears to me that the overall outcome of codifying the training will help ensure that risk practices are consistent throughout the Company.

Q. Please summarize your findings on the Company's changes to personnel in response to the Trading Losses.

A. Based on the Company's representation on the actions it took in response to the Trading Losses, it appears that the Company's personnel and

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[58] Staff/606, Dlouhy/66.

organizational changes may help address some apparent shortfalls in its organizational risk management. I find no issues with the personnel changes the Company has made subject to the Company's representation.

ISSUE 7 – RISK PRACTICE CHANGES FOLLOWING THE TRADING LOSSES

Q. Please summarize what changes the Company has made to its risk evaluation after the Trading Losses?

A. The Company has updated the following aspects of its risk practices after the Trading Losses:

- Limited the spatial and temporal areas where the Company can trade.[59]
- Required increased reporting.[60]
- Extended the upcoming period where the Value at Risk (VaR) is evaluated.[61]

Q. Please summarize your evaluation of the Company's updates to its risk controls.

A. While the Company does make some positive changes to its risk evaluation, I question why the Company has not employed more nuanced metrics to evaluate its risk.

I recognize that the Company's increased reporting when nearing its risk limits enhances oversights and allows the Company to react in a

59 Staff/606, Dlouhy/43.
60 *Ibid*.
61 *Ibid*.

timelier manner. Further, limiting trading areas should help eliminate the type of exposure that led to the Trading Losses and reporting positions at each trading hub should allow the Company to better avoid missing important information that was lost due to aggregation.

Although these changes are moving the Company in the right direction, I question why more changes to the Company's approach to (VaR) have not been implemented to add robustness checks and techniques that allow the Company to better characterize its tail risk. The Company relies on only a subset of available methods to calculate VaR and appears to only make risk decisions based on VaR calculations within a set confidence interval, which is entirely deterministic and omits all information that falls outside of that confidence interval. To address this, I recommend that the Company begin to explore the implementation of two things in its risk evaluation:

1. Probabilistic methods to calculate VaR such as Monte Carlo simulation techniques
2. Conditional VaR (CVaR) analysis

These two changes will allow the Company to peer into particular situations that may lead to large losses and to better quantify the probabilistic impact of such losses.

Q. What has the Company done to limit trading that can be done beyond the Company's physical transmission rights, across certain time periods and within current cash months?

A. PGE has imposed limits on where futures trades can be made for electricity and natural gas. This can be seen in its highly confidential attachment B to DR 519.[62] Natural gas is also limited.[63]

Q. Do you believe that this change has resulted in an overall improvement in the Company's risk practices?

A. Yes. As I discuss in my brief overview of the trading losses, the Trading Losses occurred in part due to unforeseen and unplanned-for transmission congestion which prevented PGE from remedying both long and short market positions. By implementing the changes that PGE has made, PGE has assurance it can deliver or receive electricity, therefore limiting its risk.

Q. Please describe how the Company has disaggregated positions to the trading-hub level in its daily reporting and changed its thresholds to send reports to the ERC and the Board.

A. The Company has changed two aspects of its risk reporting. First, in its daily reports, it disaggregates its reporting rather than presenting an aggregated position.[64] Second, it increases communication when it gets near to its risk limits.

62 Staff/606, Dlouhy/43.
63 *Ibid.*
64 Staff/606, Dlouhy/101.

Q. How could these changes help prevent a situation of the magnitude of the Trading Losses from happening again?

A. Although the overall VaR threshold has not been raised, these increased reporting requirements could help mitigate another situation akin to the Trading Losses by increasing awareness within the Company of its exposure. Given the size of the Trading Losses relative to the Company's existing VaR threshold, it appears to me that the threshold was not necessarily a contributing factor to the Trading Losses. Rather, there seems to have been an information gap between upper management and employees making trades, and a deficiency in how the Company implements its VaR.

Increased reporting can help to solve the information gap. I will discuss the Company's process around VaR and my recommendations later in this testimony.

Q. Do you believe that extending the window of VaR evaluation could help mitigate the risk of another event of the magnitude of the Trading Losses to occur?

A. Yes. Extending the window over which cumulative losses are evaluated gives the Company a greater pool of data from which to identify exposure.

Q. What deficiencies do you see in the Company's approach to risk evaluation?

A. The Company states that its VaR technique measures potential losses in value to the Company's energy portfolio using a variance/covariance approach at a confidence interval using various data about commodity prices, its positions and its system.[65] The Company also notes that most of its cumulative trading losses were below the VaR threshold leading up to June 2020.

While this is indeed informative, using the Company's approach to determing VaR and using a confidence interval can leave out some very useful information. First, the Company's approach has a deterministic solution. Therefore, it would be unable to pick up a sustained period of abnormal market activity. Second, although confidence intervals are useful in restricting results to what will likely occur in the market, omitting outliers can leave out important information about potential losses in extreme circumstances.

One possible solution to this is to extend the Confidence Interval to something higher than the Company currently uses, and I believe that the Company should be performing this sort of sensitivity analysis if it is not already. However, any change to the size of a Confidence Interval will necessarily leave some tail risk unanalyzed. This unknown tail risk still doesn't address one central question that appears to pivotal to the Trading Losses: What risks lie just outside what will *probably* happen in the market?

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65 Staff/606, Dlouhy/103.

Q. Are there tools that the Company can use to model a sustained period of abnormal activity that aren't easily picked up by a deterministic approach?

A. Yes. I recommend that the Company supplement its current approach with market simulations. One such method of market simulations is known as Monte Carlo simulation, where the Company makes a series of games and draws to simulate different market outcomes. Unlike deterministic approaches, Monte Carlo simulations can better capture and model how the Company's portfolio position would change if it were to encounter a sequence of "bad luck." Computers are now advanced enough that computing 1,000 or 10,000 simulations with Monte Carlo draws is relatively easy computationally and are not time intensive. Doing so would allow the Company to not only corroborate its deterministic results but also to better inform itself on low-frequency events.

Q. What can the Company do to better inform outcomes that fall outside of its confidence interval?

A. The Company can do two things, the first of which is implement some form of Monte Carlo simulation technique described above. The second is to perform CVaR analysis in addition to its VaR analysis. I recommend that the Company establish a CVaR model to manage its risk.

Q. How does a CVaR analysis differ from a VaR analysis?

A. The Company's VaR with a threshold set at any confidence interval allows the Company to estimate the maximum level of losses that will occur within the certainty provided by that interval. Put another way, if the Company uses a 95 percent confidence interval that is one sided and has a daily loss boundary of $5 million, then the Company's model predicts that it will lose less than $5 million on 95 percent of days. In this scenario, having a single-day loss of $200 billion with 19 other days with losses under $5 million still constitutes a predictive VaR model. Although this example is extreme, this is obviously a scenario that a Company would want to avoid.

CVaR analysis looks explicitly at those outcomes that fall outside of the "normal" days captured by the VaR model. This type of analysis is particularly useful for companies that operate in volatile areas.

Q. PGE is an established electric utility. Why should it implement a model that works best in volatile fields?

A. The landscape of energy is changing dramatically before our eyes. In just the last few years, the west coast has experienced dramatic swings in temperature with record highs due to climate change, increased wildfires have caused utilities to institute public safety power shutoffs, and intermittent energy sources are becoming ever more prominent. In effect, all of this has created volatility in the electricity sector unseen for years. Take for example the record heatwave that swept the Pacific Northwest and caused utilities to make snap decision about their utility operations.[66] None of this is predicted to go away any time soon, so it behooves the

[66] Staff/604, Dlouhy/12.

utility to be as well informed about low probability events when managing its risk.

Q. If the landscape of energy is changing so rapidly, why would a CVaR model that relies on distributional assumptions even help at all?

A. It is indeed the case that the landscape of energy is changing rapidly, and with that we should expect in the distributional norms around unlikely market events. Unfortunately, there is no way to know for sure how the prevalence of these events will change in a post-climate change world. This further supports the need for a well-organized risk evaluation protocol.

Despite this shortcoming, any distributional assumptions will have some probability attached to *every* market event occurring. So, although the probability of a particular event occurring may evolve over time, the chance that an event occurs *at all* should be contained in any worthwhile risk model.

In practice, climate change scientists talk about disasters becoming more prominent and harder hitting due to climate change, such. These disasters could include a heatwave that caused the Trading Losses, wildfires, hurricanes, or storms. In practice, this could mean an event with a probability of 0.1 percent now has a probability of 0.3 percent. In this example, the change in probability would not be picked up by a 95 percent Confidence Interval in a VaR analysis. However, a CVaR analysis can better capture these low-probability and high-impact events as their probability changes and better alert the Company to emerging threats.

Q. Please summarize your overall recommendation regarding the Company's updates to its risk evaluation and risk modelling.

A. Although I recognize that the Company has added internal reporting and limitation on where trades can be executed does indeed mitigate its market risk, I find that the Company's changes to its risk evaluation are insufficient. In short, I think the Company's approach to VaR is inadequate because it relies on only a single technique when others are available and doesn't properly account for tail risk. To remedy this, I recommend that the Company begin implementing a Monte Carlo method to supplement its VaR estimations techniques and begin to develop a technique to implement a CVaR to better prepare for tail risk.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualification

October 25, 2021

WITNESS QUALIFICATION STATEMENT

NAME:	Curtis Dlouhy
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance, and Audit Division
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	PhD, Economics University of Oregon, Eugene, OR Master of Science, Economics University of Oregon, Eugene, OR Bachelor of Arts, Economics & Math Nebraska Wesleyan University, Lincoln, NE
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) since June 2020 in the Energy Rates, Finance, and Audit Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. I have provided analysis and expert testimony in various contested cases including UG 388, UG 389, UG 390, UE 374, UE 390, UE 391(ongoing), and UE 394 (ongoing). Prior to working for the Commission, I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization and Antitrust Economics. My PhD dissertation covered various topics in fossil fuel markets ranging from coal mine closure, dispatchable electricity choices under carbon taxes and coal transport via railroad. While completing my PhD, I provided cost and economic analysis for the Graduate Teaching Fellows Federation as a member of their contract bargaining team.

CASE: UE 394
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

PGE Non-Confidential Responses to Staff and Parties Data Requests.

October 25, 2021

August 11, 2021

To: William Gehrke
Citizens Utility Board

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to CUB Data Request 016
Dated July 28, 2021

Request:

Refer to UE 394 / PGE / 300 / Mersereau – Neitzke / 35 / Lines 17-20. The Company states "PGE uses a discount rate of 2.53%, which is an average of the interest rates of a group of long-term high-quality AA-rated bonds. The discount rate is provided by Willis Towers Watson, and the methodology is determined in accordance with Generally Accepted Accounting Principles."

a. Please provide a narrative explanation of how Willis Towers Watson estimates the discount rate used to estimate pension costs.
b. Please provide the bond indices used to create the Company's estimated discount rate.

Response:

a. Discount rates are derived by identifying a theoretical settlement portfolio of high-quality corporate bonds sufficient to provide for a plan's projected benefit payments. These bonds are chosen by Willis Towers Watson (WTW) to provide the most efficient match between the portfolio cash flow and the projected benefit payments. If there is not a perfect match, WTW provides for the carry forward of excess cash flows to future periods. The interest rates used when carrying forward any such excess are derived from WTW's proprietary RATE:Link models or from a U.S. Treasury curve. With this handling of excess cash flows, the selected bond portfolio is sufficient to provide for the plan's projected benefit payments. The single interest rate is then determined that results in a discounted value of the plan's benefit payments that equals the market value of the selected bond portfolio. This represents the suggested discount rate. Attachment 016-A provides additional information regarding the discount rate determination.
b. Bond indices are not used in the creation of the estimated discount rate. Rather, a theoretical bond portfolio is constructed sufficient to provide for the plan's pension payments. Attachment 016-B provides the 2020 year-end discount rate analysis provided by WTW and used to establish PGE's 2021 discount rate assumption. PGE based its 2022 discount rates on assumptions used for 2021.

Attachments 016-A and 016-B are protected information and subject to General Protective Order No. 21-206.

July 23, 2021

To: Matt Muldoon
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 124
Dated June 22, 2021

Request:

A) For all PGE crew members that were moved from other projects in order to address wildfire damages, please describe why any PGE-crew cost is appropriate to include in the deferral since they are already present in base rates. B) Please identify other company crews that came to PGE service territory, and total billings for each contributing company for this wildfire event. Clearly indicate if each cost is addressed in the current general rate case or not and how.

Response:

A) PGE considers only costs that are "incremental" as appropriate and qualifying for the wildfire deferral. Incremental operations and maintenance expense (O&M) is defined as costs that are not straight-time labor (cost element 11XX). Straight-time O&M labor is excluded from the deferral because it is already included in base rates. Incremental labor that is included in the deferral is not included in the general rate case.

In Order No. 20-147, the Commission stated that it had legal authority to allow deferral of capital-related costs. Because these costs consist primarily of return on and return of incremental capital, then wildfire-related capital costs would also be deferrable until that capital is included in the 2022 general rate case (UE 394) as part of rate base. In PGE's clarifying deferral application for UM 2115 (dated October 8, 2020), PGE stated that a "significant portion of incremental costs that will be incurred for both replacement capital, as well as … O&M … expense". Based on this and Commission Order No. 20-389, which approved PGE's UM 2115 deferral, wildfire-related capital costs can be deferred. Capitalized labor incurred prior to April 30, 2022 is included in the general rate case, net of any depreciation.

B) Attachment 124-A provides a list of company crews and total billing amounts by company, inclusive of O&M and capital. Note that capitalization of contractor crews and mutual aid crews was done at a total level but included in the individual crew totals. Crew expense (O&M) from the 2020 Labor Day wildfire storm is not included in PGE's current general rate case (UE 394).

Attachments 124-A and 124-B are protected information and subject to Protective Order 21-206.

July 23, 2021

To: Matt Muldoon
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 125
Dated June 22, 2021

Request:

Please describe the basis for including any labor cost as being incremental to that included in rates. Clearly indicate if each cost is addressed in the current general rate case or not.

Response:

PGE considers only costs that are "incremental" as appropriate and qualifying for the wildfire deferral (UM 2115). "Incremental" is defined as all costs which are not straight-time labor (cost element 11XX). Straight-time labor is excluded because it's already accounted for in base rates. All overhead labor and labor loadings associated with straight-time labor are also excluded.

Regarding capitalized labor costs: In Order No. 20-147, the Commission stated that it had legal authority to allow deferral of capital-related costs. Because these costs consist primarily of return on and return of incremental capital, then wildfire-related capital costs would also be deferrable until that capital is included in the 2022 general rate case (UE 394) as part of rate base. In PGE's clarifying deferral application for UM 2115 (dated October 8, 2020), PGE stated that a "significant portion of incremental costs that will be incurred for both replacement capital, as well as … O&M … expense". Based on this and Commission Order No. 20-389, which approved PGE's UM 2115 deferral, wildfire-related capital costs can be deferred.

July 23, 2021

To: Matt Muldoon
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 136
Dated June 22, 2021

Request:

For all PGE crew members that were moved from other projects in order to address Feb 2021 Winter Storm Response, please describe why any PGE-crew cost is appropriate to include in the deferral since they are already present in base rates. Clearly indicate if each cost is addressed in the current general rate case or not and how.

Response:

PGE considers only costs that are "incremental" as appropriate and qualifying for the 2021 February Winter storm deferral (Docket UM 2156). For PGE crew members, incremental is defined as all costs which are not straight-time labor (cost element 11XX). Straight-time labor is excluded from the deferral because it is already recovered in base rates. All overhead labor and labor loadings associated with straight-time labor are also excluded from the deferral. Incremental labor included in the deferral is not included in the general rate case.

Regarding capitalized labor costs: In Order No. 20-147, the Commission stated that it had legal authority to allow deferral of capital-related costs. Because these costs consist primarily of return on and return of incremental capital, then wildfire-related capital costs would also be deferrable until that capital is included in the 2022 general rate case (UE 394) as part of rate base. In PGE's deferral application for UM 2156 (dated February 15, 2021), PGE requested that "the Deferred Amount include both capital-related and operations and maintenance costs as both are being incurred as a part of the restoration effort." Capitalized labor incurred prior to April 30, 2022 is included in the general rate case, net of any depreciation.

July 23, 2021

To: Matt Muldoon
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 137
Dated June 22, 2021

Request:

Please describe the basis for including any labor cost as being incremental to that included in rates. Clearly indicate if each cost is addressed in the current general rate case or not.

Response:

PGE considers only costs that are "incremental" as appropriate and qualifying for the 2021 February Winter Storm deferral (Docket UM 2156). Incremental is defined as all costs which are not straight-time labor (cost element 11XX). Straight-time labor is excluded because it is already recovered in base rates. All overhead labor and labor loadings associated with straight-time labor are also excluded from the deferral. Incremental labor included in the deferral is not included in the general rate case.

Regarding capitalized labor costs: In Order No. 20-147, the Commission stated that it had legal authority to allow deferral of capital-related costs. Because these costs consist primarily of return on and return of incremental capital, then wildfire-related capital costs would also be deferrable until that capital is included in the 2022 general rate case (UE 394) as part of rate base. In PGE's deferral application for UM 2156 (dated February 15, 2021), PGE requested that "the Deferred Amount include both capital-related and operations and maintenance costs as both are being incurred as a part of the restoration effort." Capitalized labor incurred prior to April 30, 2022 is included in the general rate case, net of any depreciation.

August 17, 2021

To: Curtis Dlougy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 239
Dated August 3, 2021

Request:

Please provide a map of all Tier 2 and Tier 3 areas in PGE's service territories and areas that contain transmission facilities, showing the location of such areas and facilities.

Response:

See Attachment 239-A.

August 17, 2021

To: Curtis Dlougy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 243
Dated August 3, 2021

Request:

Regarding trim cycles, please provide:

a. A narrative description of the costs associated with a single trim operation;
b. The number of trim operations projected in 2022; and
c. A breakdown of expected costs associated with an average trim operation.

Response:

a. PGE vegetation management oversees costs for an annual trim cycle by utilizing its annual operations and management budget to allocate resources in support of internal PGE vegetation management personnel. Job roles include supervision, prioritization, operational reviews, and contract management tracking. Outside services include contractors performing tree trimming following PGE guidance and adherence to the current PGE Vegetation Management Clearance Policy and Specifications. Costs associated with vendors are based on contract specifics but generally include International Brotherhood of Electrical Workers (IBEW) Local #125 union members, vehicles, and equipment to support trimming operation work types. Additional costs may include municipal and government agencies permitting fees, flagging, and safety related needs. For each individual vegetation management project, durations vary. General project management practices are applied to track costs utilizing historical data through a QuickBase tracking application for individual projects, crews, timelines, and PGE regions.

b. PGE vegetation management sets projections for its schedules using line mile estimates and then prioritizes schedules based on historical and field reviews. The current forecast for 2022 includes 4,000 miles and is based on an average of 18 line-miles per project. We forecast 222 projects for 2022.

c. PGE's expected costs for 2022 are based on local resource availability and primarily include IBEW Local #125 personnel, vehicle, and flagging cost estimates. The overall average Cost Per Line Mile is $6,600 for 2021. Assuming an average of 18 line-miles per project, we expect the average trim operation for 2021 to cost approximately $118,800. This is expected to increase for 2022 due to increasing labor costs driven by factors such as higher labor rates and costs for flagging, and lack of qualified local personnel. Given the expected cost increases compared to 2021, the estimated Cost Per Line Mile in 2022 is between $6,800-$7,000. This forecast is based on 2021 actuals; 2022 actuals may be higher, driven primarily by higher labor costs.

August 17, 2021

To: Curtis Dlougy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 244
Dated August 3, 2021

Request:

Please provide separate projections of the capital investments and total annual O&M expenses for each year of the time period 2022, 2023, 2024, 2025 and 2026:

a. Wildfire Mitigation;
b. Vegetation Management; and
c. Total Wildfire and Vegetation Management.

Response:

PGE does not budget O&M expense or make capital projections at this level of detail until the year prior to the applicable year. The amounts filed in the general rate case are the projections for 2022, with the following exception: the wildfire mitigation capital projection increased from $6 million to $10 million for 2022 pursuant to senior leadership guidance in response to an external consultant advising that a utility the size of PGE should spend approximately $20 million per year on wildlife mitigation. The external consultant compared capital spend by other utilities which have similar vegetation management requirements to determine an appropriate level of capital spend normalized by utility territory size. By increasing its capital projection for 2022, PGE is able to more quickly ramp up its wildfire mitigation investments.

August 17, 2021

To: Curtis Dlougy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 247
Dated August 3, 2021

Request:

Refer to the Vegetation Management cost estimates on PGE/800, Bekkedahl – Jenkins/54. Please provide:

a. The portion of these costs that are covered by the deferral in UM 2115;

b. The portion of these costs that are covered by the deferral in UM 2156; and

c. The portion of these costs that are covered by any other outstanding deferrals.

Response:

a. None of these Vegetation Management cost estimates are included in UM 2115.

b. None of these Vegetation Management cost estimates are included in UM 2156.

c. None of these Vegetation Management cost estimates are included in any other outstanding deferrals.

August 17, 2021

To: Curtis Dlougy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 248
Dated August 3, 2021

Request:

Please provide for each year of the time period 2000 through 2020, inclusive, the number of Vegetation Management clearance or other violations identified by OPUC staff in inspecting PGE's service territory facilities.

Response:

Attachment 248-A shows the historical vegetation graph of readily climbable trees and primary conductor vegetation contacts, provided by OPUC Staff as an attachment to the OPUC Report No. E21-53R, Portland General Electric (PGE)-Vegetation, dated July 15, 2021. No data prior to 2007 was provided.

August 18, 2021

To: Curtis Dlougy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 251
Dated August 4, 2021

Request:

Please provide the following information on each of the seven unfilled positions intentionally frozen during the COVID-19 pandemic that are referenced in PGE/400, Ajello – Batzler/17:

a. A position description;

b. Hourly wage or annual salary;

c. FTE;

d. All benefits for each position;

e. Whether this position is currently filled; and

f. A narrative description about why this position was able to be temporarily suspended during the COVID-19 pandemic.

Response:

See Attachment 251-A for the requested information.

August 18, 2021

To: Curtis Dlougy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 252
Dated August 4, 2021

Request:

Please provide:

a. A narrative description of the organizational restructuring referenced in PGE/400, Ajello – Batzler/17-18; and

b. In your response, please indicate whether any changes were made in response to the August 2020 trading losses.

Response:

a. The organizational restructuring involved the shifting of needed skill sets and positions (e.g., management and individual contributors) into Finance and Accounting (F&A) to align with long-term goals. The restructuring also involved splitting our Financial Planning and Analysis (FP&A) Corporate Planning team into two groups with one supporting Operations (i.e., Transmission, Distribution, and Generation) and the other supporting Corporate Functions (i.e., Finance, Legal, Human Resources (HR), Information Technology (IT), etc.). Corporate Planning (CP) team size and the complexity of having a single manager cover the entire CP motivated the repurposing of an existing CP position into a managerial position. Further, a position from Performance Management was moved to the Center of Excellence team to align the work more appropriately being performed in that role with the department ultimately responsible for the work output. This allowed each team to better focus on their respective areas to drive operational results and efficiencies for PGE.

b. The organizational changes referenced in PGE/400 were not in response to the August 2020 trading losses.

September 3, 2021

To: Curtis Dlouhy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Highly Confidential Data Request 518
Dated August 20, 2021

Request:

Please provide PGE's risk management policy/protocols related to wholesale energy trading in effect in July 2020.

Response:

Confidential Attachment 518-A provides the requested information.

Attachment 518-A contains highly protected information and is subject to Modified Protective Order No. 21-237.

September 3, 2021

To: Curtis Dlouhy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Highly Confidential Data Request 519
Dated August 20, 2021

Request:

Please provide PGE's risk management policy/protocols put in effect on or around January 1, 2021.

Response:

Confidential Attachment 519-A provides the requested information, and Confidential Attachment 519-B provides the most recent update to Attachment 519-A.

Attachments 519-A and 519-B contain highly protected information and are subject to Modified Protective Order No. 21-237.

September 17, 2021

To: Curtis Dlouhy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 640
Dated September 7, 2021

Request:

Refer to the Company's response to Staff DR 59. Please provide any actuarial reports supporting the Company's proposed discount rate for its pension plan.

Response:

Attachment 640-A provides the actuarially derived forecast PGE received from its actuary that includes the discount rates PGE used to forecast 2022 FAS 87 pension and FAS 106 post-retirement expenses. Please note, while the 2022 forecast discount rate of 2.70%, provided in PGE's response to OPUC Standard Data Request No. 059, Attachment 059-A, is correct, the amount provided as PGE's forecast 2022 FAS 87 pension expense is incorrect and PGE will submit a revised response. Additionally, PGE inadvertently provided an incorrect discount rate in PGE Exhibit 300, page 35, line 17.

Attachment 640-A is protected information and subject to Protective Order 21-206.

October 1, 2021

To: Curtis Dlougy
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 840
Dated September 17, 2021

Request:

Refer to PGE/800, Bekkedahl – Jenkins/53 at line 4, row 27 of Attachment A to PGE's response to Staff DR 143, and row 48 of Attachment A to PGE's response to Staff DR 311. Please discuss why these values differ and identify which value is most representative of Wildfire Mitigation capital costs.

Response:

The primary difference is that each of these covers different periods of time. Row 27 of Attachment A to PGE's response to OPUC Data Request No. 143 provides the forecast additions from January 1, 20**21** through April 30, 2022, which was $5,318,410, while row 48 of Attachment A to PGE's response to OPUC Data Request No. 311 provides the expected close-to-plant additions from January 1, 20**19** through April 30, 2022, which is $5,895,473. The testimony includes capital additions from January 1, 2019 through April 30, 2022; the testimony rounded up to say "$6.0 million of capital" in the summary sentence on page 53 of PGE Exhibit 800.

CASE: UE 394
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

Staff Pensions Testimony in UE 335.

October 25, 2021

ISSUE 7. PENSION AND POST RETIREMENT BENEFIT PLAN EXPENSES

Q. Please summarize the Company's overall request.

A. Defined benefit costs (FAS 87) included in the rate case are $21.5 million in 2017, increasing to $26.2 million in 2018, and decreasing back to $21.5 million in 2019. These costs reflect an assumed seven percent long-term rate of return on assets and use a discount rate of 3.64 percent for the pension benefit obligation. The Company will monitor the discount rate and propose a final rate no later than September 2018.[47]

PGE will continue to capitalize pension and post retirement plans in a manner consistent with PGE's method prior to the issuance of Accounting Standards Update (ASU) No. 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost." For 2019, the Company expects to capitalize $7 million of the total FAS 87 cost.[48] 401(k) costs are expected to increase from $20.7 million to $23.3 million for 2017 and 2019, respectively.[49]

Q. What are Staff's thoughts regarding the Company's proposal to update the discount rate?

A. Given that the discount rates are based on a group of long-term high quality AA-rated bonds and we are currently in an environment of increasing rates,

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[47] PGE/400, Mersereau-Neitzke/36, PGE response to Staff DR No. 222, OPUC DR No. 059 Supp 1_Attach B_CONF

[48] PGE/400, Mersereau-Neitzke/34.

[49] PGE/400, Mersereau-Neitzke/33.

Staff would expect that subsequent revision of the discount rate would be in an upward direction thereby reducing the benefit liability relative to plan assets.

Q. What are Staff's conclusions regarding the discount rate?

A. Based on the Company's responses to Staff DR No. 220, Staff believes the discount rates being used are reasonable for both the pension plan and the various postretirement benefit plans.

Q. What are Staff's conclusions regarding the long-term rate of return on plan assets?

A. Based on the Company's responses to Staff DR No. 220, Staff believes the seven percent assumed rate of return is somewhat conservative. However, the Company's observation that the decrease to seven percent has already been vetted in the previous rate case is valid. Accordingly, Staff is not proposing an adjustment in 2019.

Q. What would be the effect on 2019 pension costs if the return on assets was 7.25 percent?

A. A 25 basis point increase would decrease costs by $1.5 million.[50]

Q. Is the funded status of the Company's plans improving?

A. The Company reports the funding status of the defined benefit pension plan as 72.6 percent, 70.1 percent, and 72.4 percent for years 2015 through 2017, respectively. The Company reports the funding status of the other postretirement benefit plans as 37 percent, 41.1 percent, and 42.3 percent for years 2015 through 2017, respectively. Accordingly, the funded status of the

[50] Staff/503, PGE Response to OPUC Standard Data Request No. 060.

pension is holding steady and the post retirement plans have improved. This is evidence that the plans are generally stable and the costs being borne by ratepayers are reasonable.

Q. Has Staff identified any issues regarding pension plan valuation?

A. **[Begin Confidential]** [redacted] **[End Confidential]**

While acknowledging Staff has no specialized actuarial expertise, Staff questions this information from a common sense perspective for several reasons:

- Conceptually it makes no sense why the plan would assume promotional increases for non-union employees but not union employees, a portion of which are also, presumably, staying with the Company and moving to positions of increasing responsibility and pay as their careers progress.

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51 [redacted]

52 [redacted]

- The method does not appear to compensate for any level of employee attrition.
- The large annual increases assumed for younger non-union employees will compound to vary large numbers over a 45 year career.
- The actual employee census in any particular year will include the full range of employees at various career stages and compensation levels. Also assuming like increases for each employee appears to be "double counting" the increase from a current year service perspective.

In sum, Staff believes the assumed rates of increase could be leading to an overstatement of the pension benefit obligation and also the FAS 87 expense being borne by ratepayers.

Q. Did Staff request the Company to provide a range of cost scenarios with different assumptions?

A. No, Staff recognizes that running additional actuarial calculations would be costly for the Company. However, Staff would like to have continuing dialogue with the Company and parties both to allow parties to comment and also to allow the Company to provide additional information prior to asking the Company to recalculate the pension benefit obligation.

Q. Does Staff have any concerns about the Company's implementation of Accounting Standards Update (ASU) No. 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost"?

A. Yes, the footnotes to the Company's 2017 financial statement indicate the Company has set up a regulatory asset for the FAS 87 expense in excess of service cost. This amount is estimated at $3 million annually.

Q. Did the Company provide additional information?

A. Yes the Company's response to Staff DR No. 224 indicates the $3 million non-service cost has been capitalized as plant for regulatory purposes. For Security and Exchange Commission (SEC) purposes it is set up as a regulatory asset that will be amortized. The Company states that it has developed a "dual recordkeeping system" to keep track of the SEC and regulatory basis differences.

Q. Is Staff proposing a rate case adjustment?

A. No, the Docket No. UE 319 settlement (Order No. 14-511) and FERC Docket No. AI18-1-000 "Accounting and Financial Reporting for Pensions and Post-retirement Benefits other than Pensions" do not specifically discuss a regulatory asset though the existence of one is implied. Staff is including this in testimony to memorialize that a basis difference now exists.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 604

Financial News

October 25, 2021

https://www.wsj.com/articles/delta-variant-set-to-slow-but-not-derail-global-economic-recovery-11632219656

ECONOMY

Delta Variant Set to Slow but Not Derail Global Economic Recovery

OECD cuts growth forecast for this year but raises projections for 2022

Workers produce adhesive tapes for flexible printed circuits at a factory in Yancheng, China.

PHOTO: AGENCE FRANCE-PRESSE/GETTY IMAGES

By Paul Hannon
Sept. 21, 2021 6:20 am ET

The fast-spreading Delta variant of Covid-19 has slowed the pace of the global economic recovery but won't derail it, according to new forecasts released by the Organization for Economic Cooperation and Development.

In its latest quarterly report on the economic outlook published on Tuesday, the Paris-based research body lowered its growth forecasts for the global and U.S. economies in 2021, the first downgrade since December of last year, when new infections were surging.

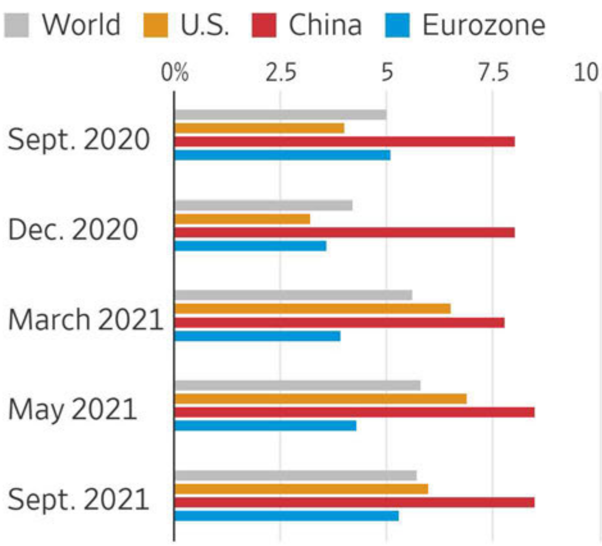
But it also raised its forecasts for next year, indicating that some output has been delayed by, rather than lost to, the Delta surge. It also raised its forecasts for inflation this year, but continues to expect that the pace of price rises will ease in 2022 as vaccination programs advance in Asia and other parts of the world.

"We still think it's transitory," said Laurence Boone, the OECD's chief economist. "The disruption of supply chains is mostly due to the vaccine situation."

Changing Expectations

Over the past year, the OECD's growth forecasts for 2021 have changed as the pandemic has waxed and waned.

Economic growth forecasts for 2021



Source: Organization for Economic Cooperation and Development

The OECD lowered its growth forecast for the U.S. economy in 2021 to 6% from the 6.9% projected in May, and trimmed its global growth forecast to 5.7% from 5.8%. It raised its growth forecast for the eurozone, but left its projection for China unchanged despite worries about the country's property market as China Evergrande Group appears on the brink of collapse. The company's debt burden is the biggest for any publicly traded real-estate management or development company in the world.

"We are concerned about what's happening on the financial side," Ms. Boone said.

The OECD forecasts come amid mounting signs of a cooling of growth after the period of rapid expansion that accompanied the reopening of parts of the services sector in a number of large, rich countries that were first to vaccinate large shares of their populations.

The Delta variant appears to have taken some of the momentum out of that process of reopening, while its rapid spread in Asian countries that hadn't been able to vaccinate their populations has prompted new restrictions on manufacturing and logistics that have worsened shortages of parts and finished consumer goods destined for Western markets.

“That’s been central to the problems we face,” said Stephen Loftus, chief commercial officer at Brompton Bicycle Ltd., a London-based maker of folding bicycles.

The company has seen a surge in demand as workers in its home city and elsewhere seek safe alternatives to what were perceived as risky public transport systems. It made a third more bicycles in the period from April to August than it did over the same stretch of 2020, with sales to the U.S. up by half over the past 12 months.

But Mr. Loftus believes it could have made and sold many more of its bicycles if it had been able to get hold of the parts it needed, while factory shutdowns in Vietnam designed to slow the spread of the Delta variant hindered its ability to make and sell a range of bags that fit its bicycles.

However, Mr. Loftus doesn’t believe that unsatisfied demand has gone away, and that means Brompton will have at least another year of rising output, likely boosted by fresh buyers as more workers return to their workplaces in the world’s large cities.

“We’ve got a lot to pick up from the demand that hasn’t been fulfilled,” he said. “That’s reflected in the fact that we have retailers that have got no stock in store.”

With demand for many consumer goods still strong, and many services industries yet to return to their pre-pandemic levels of output, the global economic recovery is set to continue into 2022, aided by vaccination programs. According to the OECD, the U.S. economy will grow 3.9% next year, a faster expansion than the 3.6% increase in gross domestic product that it forecast in May. Globally, it sees economic output rising 4.5%, slightly faster than its previous projection.

Bottlenecks of the kind that have held Brompton back have contributed to a recent pickup in the pace of price rises across the world, and the OECD raised its inflation forecasts for most of the Group of 20 largest economies. Responding to its own increase in costs, Brompton said it had raised bicycle prices by around 5%.

Construction of Evergrande Cultural Tourism City, a mixed-used residential-retail-entertainment development in Taicang, China, has been halted.

PHOTO: VIVIAN LIN/AGENCE FRANCE-PRESSE/GETTY IMAGES

But the OECD doesn't expect to see further pickups in inflation during 2022, and sees the pace of price rises easing in the U.S. and the eurozone, although it does expect an acceleration in China. It expects expanding vaccine programs in poorer countries to help ease bottlenecks. While a rich country like Spain has vaccinated just short of 90% of its adult population, Indonesia has inoculated roughly a third.

Even so, the OECD said central banks in rich countries should set out their path away from policies designed to provide emergency support to their economies. But its main concern lies with a number of large developing economies, such as Brazil, which have seen inflation rise rapidly, prompting their central banks to raise their interest rates quickly. With debt levels high, rising interest payments for households and businesses could delay the recovery.

Write to Paul Hannon at paul.hannon@wsj.com

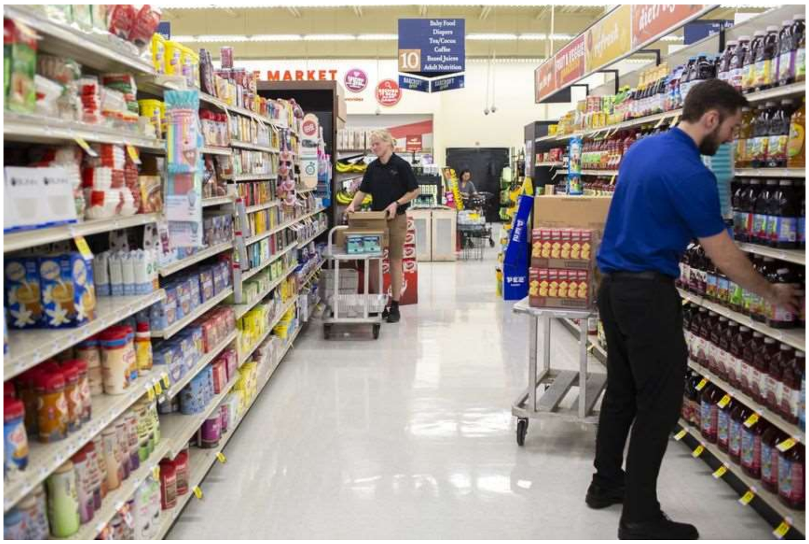
Appeared in the September 22, 2021, print edition as 'Delta to Slow Recovery, OECD Says.'

https://www.wsj.com/articles/broader-inflation-pressures-begin-to-show-11633339800

U.S. ECONOMY

Broader Inflation Pressures Begin to Show

Price indexes that exclude extreme changes point to inflation running ahead of Fed's 2% target



There were signs in August that cost increases related to supply disruptions had begun easing.

PHOTO: KRISTEN NORMAN FOR THE WALL STREET JOURNAL

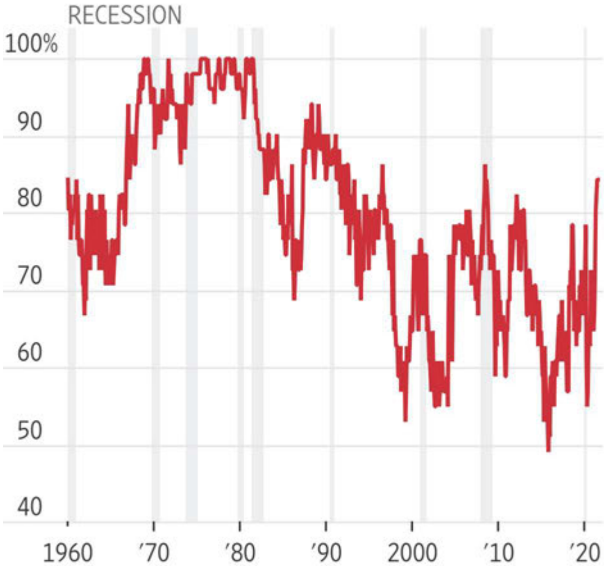
By Gwynn Guilford
Oct. 4, 2021 5:30 am ET

While many pandemic-driven price pressures are easing, broader sources of higher inflation are replacing them.

That is the message from a slew of alternative inflation measures that strip away price changes due to idiosyncratic swings in supply and demand, and home in on longer-lasting pressures.

These alternative indexes are signaling "inflation is not as extreme as what the headline or traditional core shows right now, but it is picking up," said Sarah House, director and senior economist at Wells Fargo.

Portion of items in price index with price increases



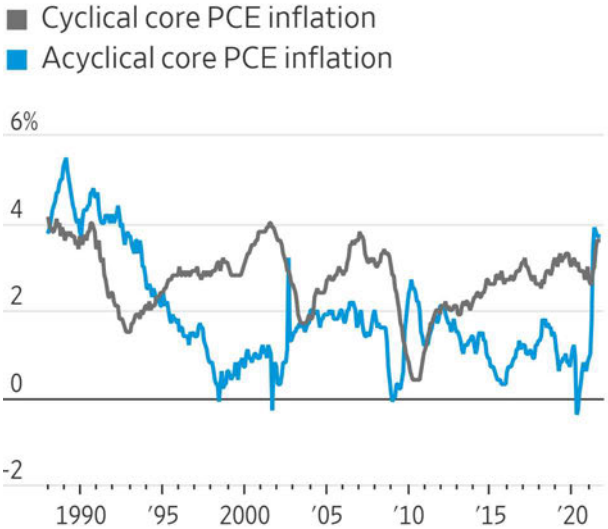
Note: Based on price index of personal consumption expenditures.
Source: Federal Reserve Bank of San Francisco

"All of these measures have moved from signaling price stability to signaling sharp accelerations in underlying inflation," said Brent Meyer, an economist at the Federal Reserve Bank of Atlanta.

Some economists interpret this as inflation returning to levels consistent with a healthy economy, after being too low before the pandemic. "To now see price pressures picking up, but not at extremely worrying levels—it's progress," said Blerina Uruci, senior U.S. economist at Barclays.

Inflation as measured by the Labor Department's consumer-price index was 5.3% in the 12 months through August, close to the highest in 12 years. Economists generally expect that to fall, but disagree on how much. They attribute much of the recent surge in prices to temporary causes—such as a post-vaccine spending upsurge, specific supply-chain problems and other production bottlenecks—that should fade as businesses ramp up output.

Cyclical and acyclical core* personal-consumption expenditures price index



Note: Cyclical index includes items that tend to rise in tight job markets; acyclical includes all else.
*excludes volatile food and energy prices
Source: Federal Reserve Bank of San Francisco

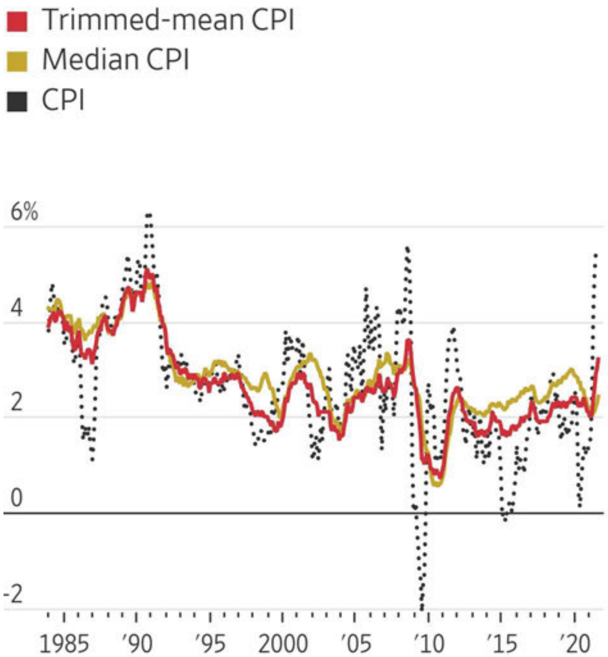
But a key question is whether prices will continue to rise more persistently once these temporary disruptions end.

The Federal Reserve has argued that inflation will recede to just above its 2% target by 2022. Nonetheless, Fed Chairman Jerome Powell, asked last week whether inflation is now broader and more structural than earlier this year, responded, “Yes, I think it’s fair to say that it is.”

There were signs in August that cost increases related to supply disruptions had begun easing. The core consumer-price index, which excludes the often volatile categories of food and energy, rose just 0.1% from July, the smallest monthly increase since February. Prices for used vehicles dropped sharply, as did hotel rates and airline fares, possibly due to the impact of the Delta variant on travel.

Alternative inflation measures can help suggest where inflation is headed, by cutting out statistical noise or zeroing in on historical pricing patterns, said Alex Lin, U.S. economist at BofA Global Research. For example, some remove extreme price swings like June’s surge in used-vehicle prices, which accounted for more than one-third of that month’s CPI increase.

Consumer-price index, percentage change from a year ago, vs. Cleveland Fed's alternative measures



Note: Trimmed-mean CPI excludes most extreme price changes. Median CPI captures the median price change.
Source: Federal Reserve Bank of Cleveland; Labor Department

The Cleveland Fed's 16% trimmed-mean CPI—which lops off the most extreme price changes—and its median CPI, capturing the middle-most price change, both grew at the same month-over-month rate in August as in July, suggesting that falling prices for airline fares, hotels and rental cars caused the overall CPI to overstate the slowdown in inflation.

The inflation shown by these indexes is lower than the trend in the CPI and core CPI, but still well above 2%, and—unlike those mainstream measures—continued to climb in August. The trimmed-mean CPI rose 3.2% in August compared with the same month a year earlier, up from 3% in July and well above the 2% average between 2012 and 2019.

The rising trimmed mean alongside a more sluggish pickup in the median CPI signals that while many prices are experiencing above-average inflation, most are not, said Robert W. Rich, director at the Cleveland Fed's Center for Inflation Research.

Atlanta Fed's sticky-price consumer-price index

Note: The index includes only items whose prices change relatively infrequently.
Source: Federal Reserve Bank of Atlanta

The median suggests "inflation will move back down to a range consistent with the Fed's long-term target, while the trimmed mean is suggesting there is more upside risk," he said. The unprecedented nature of the pandemic shock makes interpreting these movements unusually hard, he cautioned.

An index from the San Francisco Fed that reslices CPI based on historical pricing patterns also signals that temporary price spikes caused by imbalances in supply and demand are fading.

This index regroups the Commerce Department's core personal-consumption expenditure price index into a cyclical index, whose components are more sensitive to the strength of the economy because they go up when the labor market tightens, and into an acyclical series of all other prices. During expansions of the last 25 years, acyclical inflation was usually lower than cyclical inflation, but it was faster from April to June. Now the two are about the same.

SHARE YOUR THOUGHTS

Have you noticed inflation in items that aren't directly affected by shortages? Join the conversation below.

The Atlanta Fed's sticky-price CPI is also signaling a pickup in underlying inflation. The index includes only items whose prices change relatively infrequently, meaning that they react slowly to changes in economic conditions—for example, medical care and rent.

"By tracking this measure, we think we're getting something that's telling us about... inflation a year or two or three out. And that measure is starting to move up," said the Altanta Fed's Mr. Meyer. The sticky-price CPI in August rose 2.6% from a year earlier, a slight acceleration from July, and nearing the 2.8% rate that prevailed just before the pandemic.

The significant increase in price pressure signaled by this and the other indexes is a potential worry, Mr. Meyer said.

Bracing for Inflation

Analysis from The Wall Street Journal, selected by the editors

ECONOMY
Broader Inflation Pressures Begin to Show

GREG IP
Fed Expects 'Transitory Inflation' to Last a While

STREETWISE
On Inflation, Investors Can Only Hope to Keep Getting Lucky

WORKERS
Rising Prices Eat Up Pay Gains for Low-Wage Workers

CONSUMERS
Five Ways You Are Paying More for Food

ECONOMY
Inflation Threat Boosted by Long-Term Shifts

CHARTS
Inflation Looks Less Severe Using Pre-Pandemic Comparisons

INTERACTIVES
Calculate Your Own Consumer Price Index

Write to Gwynn Guilford at gwynn.guilford@wsj.com

Appeared in the October 5, 2021, print edition as 'Indexes Signal Inflation Pressures Are Spreading.'

https://www.newsdata.com/clearing_up/clearing_it_up/report-short-position-in-sw-california-led-to-pge-trading-losses-in-q3/article_7a26d9b8-4180-11eb-b04c-f7d8f9875a4b.html

TOP STORY

Report: Short Position in SW, California Led to PGE Trading Losses in Q3

Steve Ernst
Dec 18, 2020

Portland General Electric's third quarter trading losses were the result of being caught short in Southwest and California power markets and long in Pacific Northwest markets as wholesale prices spiked and transmission capacity was limited, according to an independent review of PGE's energy trading activity that led to the $128 million loss.

A special committee of PGE's board of directors announced its finding Dec. 18 in a press release.

The committee concluded the trades were "ill-conceived" and revealed opportunities for improving the utility's energy trading policies and practices.

Additionally, the board of directors concluded that the actions the company began taking in August to enhance oversight of energy trading and associated risk management reporting, policies and practices are consistent with the committee's recommendations and will be monitored by the board.

PGE was short in a market where energy prices at Palo Verde cleared at $1,401/MWh on Aug. 18 and $1,640/MWh on Aug. 19, and power reserve shortages in California forced blackouts and price spikes of over $1,000/MW in the California ISO.

The rolling blackouts were the first called in California since the energy crisis of 2000-2001. A preliminary root-cause analysis issued by California agencies cited climate change-induced high temperatures, failure to meet planning targets, and certain practices in the day-ahead electricity market as causes.

On Aug. 18, as the heat was building across the West, and reserves in California were shrinking, CAISO suspended convergence bidding—which allows participants to take a financial position in the day-ahead market and liquidate it in the real-time market. Convergence bids are virtual, in that no physical energy is delivered or consumed nor are they backed by physical assets.

PGE announced Aug. 24 it suffered "significant losses as wholesale electricity prices increased substantially at various market hubs due to extreme weather conditions, constraints to regional transmission facilities, and changes in power supply in the West."

The company reported initially that its energy portfolio lost $104 million, along with unrealized mark-to-market losses of $23 million. Total third quarter losses in PGE's energy portfolio were estimated to be up to $155 million subject to market conditions, the utility said in a U.S. Securities and Exchange Commission filing.

On Sept. 2, PGE announced its final energy trading losses came to $128 million, and updated its 2020 earnings guidance to $1.40 to $1.60 per diluted share. The utility initially revised its earnings guidance for 2020 from $2.20 to $2.50 per diluted share to $1.30 to $1.60 per diluted share immediately after the losses were announced.

"Certain PGE personnel entered into a number of energy trades during 2020, with increasing volume accumulating in the second quarter and into the third quarter, resulting in significant exposure to the company," Maria Pope, president and CEO of PGE, said in an email to employees in August. "Simply put, these were ill conceived trades."

The special committee released five recommendations, which the utility has already implemented.

- PGE has brought in additional experienced risk management personnel and replaced the Power Operations general manager with a new interim leader.
- Power Operations personnel are operating under revised policies designed to prevent positions of the type that led to the losses. The improved policies place controls on the ability of personnel to enter into wholesale energy transactions to the extent that PGE does not have physical or financial delivery capability.
- Energy trading activity reporting has been improved to ensure greater visibility into portfolio risk.
- Energy Trading Risk Management now reports through a Risk and Compliance team that reports to the CEO. Effective Jan. 1, 2021, Power Operations will report to the VP of Strategy, Regulation and Energy Supply.
- The individuals who previously were placed on leave are no longer with the company.

In addition, the compensation and human resources committee of the board of directors concluded that it would be inconsistent with PGE's pay-for-performance philosophy for certain senior leaders to receive annual incentive compensation. Accordingly, the CEO, the CFO and one additional executive officer will not receive any annual incentive compensation for 2020.

"The Board is confident that the actions the management team implemented and continues to take will make PGE an even stronger company, better positioned to carry out our mission of powering the communities we serve." Jack Davis, chair of the PGE board, said in a prepared statement.

Steve Ernst

Editor - Clearing Up

Steve began covering energy policy and resource development in the Pacific Northwest in 1999. He's been editor of Clearing Up since 2003, and has been a fellow at the Institute for Journalism and Natural Resources and University of Texas.

UTILITY DIVE

DIVE BRIEF

'What in the world is happening with the weather': Western heat wave raises questions for grid planning

Published July 1, 2021

Kavya Balaraman
Senior Reporter

Dive Brief:

- The heat wave that spread across the Pacific Northwest over the weekend, leaving utilities racing to alert customers and prepare their systems, is an indication that the region's power sector will need to take a closer look at their reliability planning, experts say.
- At a meeting with Western state governors on Wednesday, President Joe Biden emphasized his administration's commitment to tackling climate impacts like wildfires and extreme heat, telling utility leaders that "we are ready to work with you to make sure that people have access to power, including air conditioning, under these extreme demand conditions, while continuing to advance our climate goals."
- "The biggest lesson learned that everyone needs to look at very closely is what in the world is happening with the weather," Arne Olson, senior partner with Energy and Environmental Economics, said. "Over the long run, we do need to readjust our load forecasts and expectations for that duration and intensity of these heat waves," he added.

Dive Insight:

The Pacific Northwest experienced unprecedented temperatures over the weekend and early this week, with Portland breaking records three days in a row, and touching 116 degrees on Monday. Utilities had begun alerting customers to help conserve electricity during the middle of last week.

On Wednesday, Pacific Power noted in a press release that it did not anticipate power supply issues, but that extreme weather has the potential to produce localized outages. Portland General Electric (PGE) prepared for high demand with extra cooling systems to prevent critical distribution infrastructure from overheating, as well as by having crews on standby over the weekend to respond to outages.

Thousands of PGE customers did experience outages over the weekend, caused not by system planning issues but rather due to strained infrastructure and equipment failure. Although PGE did set peak load records on Sunday and Monday, it was able to meet that demand, utility spokesperson John Farmer said.

"As outages occurred, our teams were very quick to respond. Most outages were addressed within hours [or] maybe half a day," he said.

Pacific Power did not forecast or face any power supply interruptions due to the heat wave, spokesperson Drew Hanson said — the PacifiCorp subsidiary has access to over 16,500 miles of high-voltage transmission lines across ten states, allowing it a multitude of generation resources. While Pacific Power did experience some local outages in its service territory, it isn't clear yet whether those were heat-related or not.

Meanwhile, Avista, which provides electricity to around 400,000 customers in the region, had unplanned outages on

Monday due to high temperatures and demand, and planned, targeted outages on Tuesday. The utility asked customers to conserve energy through Thursday from 1 p.m. to 8 p.m., noting that the "unprecedented and sustained extreme high temperatures are putting a strain on the electric system that serves customers."

Power sector faces planning and infrastructure questions

The heat wave could have longer-term implications for system planning in the Pacific Northwest. Although there was largely enough market supply to get power providers through this event, the region could have seen a different result had a few things gone differently, Ben Kujala, director of power planning at the Northwest Power and Conservation Council, said — for instance, the region had more hydropower resources to work with in June than it would in, say, August.

The heatwave was outside of anything the Pacific Northwest has experienced in the past, he said. "And a huge amount of utility planning is based on looking at our previous experience."

A key question for electricity system planners is understanding load — while there's some preliminary data on the load impacts of the heat wave, planners will likely be able to do a deeper dive when they get official data down the line, according to Kujala. Another issue is heat-related equipment failure, like powerlines sagging during hot weather conditions.

"The hotter it is, the more they sag and the less power you can send down them. So there's a lot of considerations [around] these sorts of events the utilities have to... take into account," he added.

Another complication is that the the western U.S. has been seeing more big, region-wide weather events, Olson added. Traditional system planning involves different parts of the region helping each other out — but when temperatures are high everywhere, like this week, "that's an additional challenge the region will need to take into consideration. They may not be able to rely as much on their neighbors as they have been in the past."

CASE: UE 394
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 605

Confidential Attachments to Responses to Data Requests

October 25, 2021

Exhibit 605

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 21-206

CASE: UE 394
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 606

Highly Confidential Responses and Attachments to Data Requests

October 25, 2021

Exhibit 606

IS HIGHLY CONFIDENTIAL AND SUBJECT TO

MODIFIED PROTECTIVE ORDER NO. 21-237

CASE: UE 394
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

REDACTED

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Nadine Hanhan. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. In my testimony I describe my review of the capital costs of PGE's transmission projects and some projects that are a combination of transmission and distribution (together referred to as "transmission projects"). I also provide a brief overview of the PGE's proposed treatment of any increases in transmission sales revenue that may stem from PGE's planned FERC rate case, in addition to an update on PGE's reclassification of assets as a result of docket UM 2031.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1 – TRANSMISSION PROJECTS, INCLUDING IOC

Q. Could you please provide a description of the projects you reviewed?

A. Yes. I reviewed a variety of different projects. These included blanket transmission projects, the Integrated Operations Center (IOC), a variety of new substations PGE is building primarily in or around the Hillsboro area, and other miscellaneous projects.

Q. Could you please provide a description of the process through which you reviewed PGE's transmission projects?

A. Yes. Staff structured its process based on Commission guidance in Order No. 20-473, where the Commission encouraged review of capital investment by sampling:

> Due to the sheer number of capital projects that are included for recovery in a typical general rate case, we do not expect Staff to review all of the underlying documentation for every capital project proposed for recovery, regardless of size. Rather, the initial review process should be tailored to the scale of the proceeding, and employ sampling, particularly where there are numerous smaller projects, to identify areas of concerns, consistent with the approach addressed in the pre-rate case audit report.

There were over 100 projects included in the nearly $1.5 billion at issue in this case.[1] Staff reviewed the need for and costs of each transmission project with total loaded costs above $6 million:

- Integrated Operations Center (IOC) ($215.2 million)
- T&D Major System Inspect, Replace ($156.5 million)
- Butler Substation Project ($70.6 million)
- Harborton Reliability Project Phase 1 ($56.1 million)

1 Staff/702, PGE Response to Staff DR 311.

- Blue Lake Phase II Project ($36.9 million)
- Helvetia Substation Project ($22.4 million)
- Rock Creek Substation ($21.5 million)
- Roseway Substation Project ($20.4 million)
- McGill Substation Project ($16.9 million)
- Horizon Phase II Project ($13.3 million)
- Round Butte Transmission Upgrades ($11.8 million)
- Trans. Line Clearance Mitigation ($9.6 million)
- Install Horizon VWR3 Transformer ($9.1 million)
- Reconductor Murrayhill-St Marys ($7.9 million)
- Transm Full Pole Inspct & Replace ($7.6 million)
- Rebuild Grizzly-RB 500kV Towers ($6.9 million)
- St Marys Battery Addition ($6.4 million)

Note that for these numbers, Staff relied on costs from PGE's response to Staff DR 311.[2] For projects below $6 million, Staff opted to take a sampling approach where Staff took select projects from within a particular cost group (delineated below). If Staff found no concerns with the sample, Staff stopped sampling other projects in the cost group. If there was a concern, Staff would have written a data request ("DR") to investigate further, then selected another sample from the cost group, and repeated the cycle. If Staff had no concerns with the second cycle sample, Staff's review would be complete for that cost group. Otherwise, Staff would have repeated this process for a third sampling cycle. Below are the sampled projects.

- 2 projects reviewed between $5 and $6 million
- 1 project reviewed between $4 and $5 million
- 2 projects reviewed between $3 and $4 million
- 1 project reviewed between $2 and $3 million
- 5 projects reviewed between $1 and $ 2 million
- 3 projects reviewed between $500,000 and $1 million.

[2] Staff/702, PGE Response to Staff DR 311. Note that some of these costs differ from PGE's Opening Testimony numbers.

The above projects sampled are:

- Customer Data Centers
- Orenco Substation 115kV rebuild
- Intel Water Add and Replace Cables
- Strategic Spare Substation Equip
- Dist System Line Construction
- Nike Campus UG Primary Service
- Substation Rerock - multiple sites
- PGE/DTNA HD charging Demonstration
- Underground Locating
- EV Charging Network Expansion
- Fairview Substation Upgrades
- UG Core Cable Replacement
- Durham Substation Seperation [sic]
- Centennial Substation Upgrades

A full list of the projects, including the fully-loaded costs and in-service dates, that make up the nearly $1.5 billion in Exhibit PGE/800, Table 1, is included in Exhibit Staff/702.[3]

Q. Did Staff find a need for further review or adjustments for the sampled projects in the previous question?

A. No. In general, Staff did not flag any issues that triggered a second cycle of sampling to review the need for the project or the costs. Staff could not immediately identify any evidence pointing to mismanagement of projects or cost overruns. However, Staff is still reviewing the projects and reserves the right to recommend additional adjustments in Reply Testimony. Further, Staff identified three projects under $6 million that were not in service as of the date of the rate case and for which Staff does not yet know the total costs or whether they will be in service when new rates go into effect.

[3] Staff/702, PGE Response to Staff DR 311.

Q. Do you have concerns or adjustments for the projects above $6 million?

A. Yes. Staff has concerns relating to an apparent lack of cost control over amounts invested in some of these projects. The remainder of this section of testimony will address adjustments for some transmission projects related to this concern. In addition, Staff has identified four projects above $6 million that were not in service as of PGE's filing of this case and for which Staff does not know the total costs or whether they will be in service.

Q. Which projects may not be in service by the time rates go into effect?

A. Below is a table listing seven transmission projects above $1 million that Staff identified as not in service as of the rate case filing and may not be in service when tariffs are effective as a result of this general rate filing.

Table 1 - Projects Not in Service as of Rate Case Filing[4]

Project	Cost	In-Service
Integrated Operations Center (IOC)	215,198,605	Nov-21
Helvetia Substation	22,449,119	Aug-21
Reconductor Murrayhill-St Marys	7,927,599	Apr-22
St Marys Battery Addition	6,396,181	Apr-22
Milliken Tower Reinforcement_SE PDX	5,625,890	Sep-21
Restore Bethel-RB 230 kV Line	4,519,473	Nov-21
Project BaT	1,651,187	Oct-21

Q. What are the concerns regarding project timelines and in-service dates?

4 Staff/702, PGE Response to Staff DR 311.

A. Staff may be unable to evaluate the prudence of the final costs for projects still under construction while a rate case is pending. Given the timing of testimony and other milestones in this rate case, it may be difficult to determine whether the Company was able to anticipate knowable problems and meet project deadlines. Failure to meet deadlines can, for various reasons, result in cost overruns.

This problem may be particularly significant in this rate case because of COVID-19. That is, there is the question of whether the Company was or will be able to acquire the necessary equipment, labor, and materials to meet its deadline of April 1, 2022. In the midst of the challenges of a global pandemic, risks to ratepayers should be minimized, and costs should be disallowed in the event that in-service dates are not met.

Q. Even though you are still expecting additional information in this case, could you give a summary of your initial recommendations?

A. First, for each of the seven projects that were not complete at the time PGE filed its rate case and are listed above, PGE must file an officer attestation that the project is in service prior to March 31, 2022, to allow inclusion of the project in rate base. Any projects for which no attestation has been filed may not be reflected in rates charged to customers resulting from this docket. The Company would not be precluded from seeking ratemaking treatment in a future general rate case.

Second, Staff recommends costs for these seven projects be capped at the total cost forecasted for the projects as of the date of the hearing in this case. Any costs for these projects that exceed those forecasts would be eligible for inclusion in a subsequent rate case, subject to a prudence review.

Q. How do you propose to address the concern regarding timing of prudence reviews and lack of attestations that may occur for some projects?

A. The final rates PGE calculates in compliance with the Commission's final order in this case must be consistent with Staff's recommendation. To the extent an attestation for a project identified above is not filed by March 31, 2022, the project costs must not be included in rate base. To the extent a project is completed after the hearing, any amount included in rate base cannot exceed the total forecasted as of the time of the hearing.

General Cost Tracking Concerns

Q. Please briefly describe how you structured your review.

A. After PGE filed its rate case, Staff and other parties sought discovery showing the justification for and cost of each of the projects that PGE seeks to include in rate base. Staff obtained "Project Justification Forms" (PJFs) for each project. PJFs generally include a brief description of a project, its purpose, and a running account of amounts initially budgeted for the project and increases and decreases to the project budget throughout its construction. **[BEGIN CONFIDENTIAL]** [redacted].[5] **[END CONFIDENTIAL]**

Q. Did you run into any difficulties in your review?

A. Yes, many. First, Staff received multiple iterations of the PJFs from the Company. Staff received a batch of PJFs on August 13 that contained sparse information. After Staff met with PGE to understand how the PJFs were supposed to show the justification and costs of a project, PGE discovered that it had incorrectly printed the PJFs and that a significant amount of information had been omitted from the forms sent to Staff. Staff received a second, more

[5] See Staff/704 for all PJFs.

comprehensive version of the PJFs on September 1. However, information was still missing from the PJFs sent in this batch. Staff submitted additional data requests asking for information that appeared to be omitted from some of the PJFs.

For example, in DR 680 parts (a) and (c), Staff referred to text boxes within a PJF that appeared to have cut-off text and asked for the full PJF. PGE only provided complete text boxes in response to these requests rather than a complete form, which was of concern to Staff.[6] As a result, it was impossible to verify that Staff has received a complete PJF for this project, or any project, and Staff continues to be concerned that it does have not a full cost account of projects from PGE.

A second issue is that when Staff first asked for "change orders" for the projects, PGE objected because it claimed the request was "vague" and the orders were "burdensome" to produce.[7] Staff was very surprised by this objection. Staff's general experience and understanding of previous rate cases has been that change orders are not difficult to identify, and generally come with clear and specific explanations of any cost overruns. Though PGE eventually agreed to provide change orders, it was for a limited set of projects, and only over a certain threshold (i.e., change orders associated with project orders above $750,000), which does not give Staff insight into the full record of cost changes to a project.

6 Staff/703, PGE Response to Staff DR 680.
7 Staff/702, PGE Response to Staff DR 312.

Additionally, the change orders do not map to any of the cost increases in the PJFs and do not provide any context as to reasons behind the increases. Such documentation should have been sufficient in determining where any cost overruns occurred, where project costs increased due to unknown and unknowable issues, where planning failed to timely address known and knowable information at the time of decisions, and contractor or subcontractor error. Most importantly, even the Commission relied on change orders in last year's PacifiCorp rate case, UE 374, to disallow, or decline to allow, costs.[8] Thus, PGE should have known the type of information Staff was asking for and produced it.

PGE did reach out to Staff about the PJFs and the change orders, and both parties had multiple calls so that PGE could clarify the subject matter. It slowly became apparent to Staff that PGE appears to rely on the PJFs as "the" document of record for project budgeting and costs. Staff believes the PJFs are ambiguous and unintuitive. Even with clarifications by the Company, they still do not provide sufficient information to determine how costs were managed. Further, if this truly is the document of record for costs by PGE, Staff is very concerned about how PGE controls costs.

Q. How does PGE manage costs for its projects?

A. It is Staff's understanding that for the most part, PGE **[BEGIN CONFIDENTIAL]** [redacted]

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8 Order No. 20-473, page 39.

[redacted].[9] [redacted].[10]

[redacted].[11] [redacted]

[redacted][12] **[END CONFIDENTIAL]**

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9 Staff/703, PGE Response to Staff DR 655.
10 Staff/703, PGE Response to Staff DR 660.
11 Staff/703, PGE Response to Staff DR 660.
12 Staff/703, PGE Response to Staff DR 660.

Q. Why is any of this a problem?

A. There are several reasons why this is a problem. **[BEGIN CONFIDENTIAL]** [redacted]

Q. [redacted]

A. [redacted]

Q. [redacted]

A. [redacted].[13] **[END CONFIDENTIAL]**

Q. How are ratepayers harmed by PGE's current approach to budgeting and cost management?

A. Overall, Staff is concerned that savings associated with good management of projects will not be passed onto ratepayers under this approach. Instead,

[13] See Exhibit Staff/704.

benefits for well managed projects could be absorbed and exceeded by badly managed projects and cost overruns. Under the Commission's precedent, utilities are required to prudently manage the costs of new capital investments. PGE's annual budgeting process appears to eliminate controls that ensure this occurs. Further, it makes it very difficult to conduct a prudence review of the costs of any one project.

Q. Earlier you mentioned your concern with the PJFs. How does this fit into Staff's issues with the Company's approach to budgeting and cost management?

A. The PJFs are insufficient, unintuitive, and are not conducive to regulatory oversight for prudence review. The PJFs primarily record budget changes but often provide little insight into the underlying circumstances necessitating the changes. Although the PJFs document **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** they are not useful for documenting why those approvals were needed or providing evidence to show the projects were managed prudently. They also do not generally provide detail for project milestones (e.g., planning vs. execution).

Staff is particularly concerned with the absence of **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]** This means it is difficult to identify whether a project exceeded the costs budgeted for the project.

Staff invites PGE, in its Reply Testimony, to clarify its cost control process and protocols and reassure the Commission, Staff, CUB, AWEC, and other stakeholders of a much higher internal standard for cost tracking than is apparent from discovery. Above all, PGE should clarify what cost accountability mechanisms are in place at the Company; any changes in its capital investment processes since the last rate case; and how PGE plans, maintains, and meets its budget targets. If PGE's clarifications in Reply Testimony are insufficient, Staff may recommend a general disallowance to address PGE's lack of oversight on capital spending and incent PGE to improve its processes.

Project-by-Project Analysis

Q. **What capital projects does your project-by-project analysis cover?**

A. My analysis covers the 17 T&D projects above $6 million that are listed on pages 2-3 of my testimony.

IOC

Q. Please describe your review of the IOC ($215.2 million).

A. Staff reviewed testimony, exhibits, discovery, and PJFs pertaining to this project. The IOC will serve as an umbrella facility that houses a variety of PGE's grid operations, including a System Control Center (SCC), Cyber Security, Physical Security, Network Security, and a new Distribution

System Operation (DSO) team that will monitor and manage the details within the distribution network.[14]

Q. Do you have any concerns with PGE's decision to build an IOC?

A. No. Based on Staff's review of PGE's Seismic Evaluation Report[15] and PGE's testimony,[16] Staff believes it is reasonable of PGE to move core operations outside of the Portland downtown area.

Q. Do you have any concerns with the IOC project?

A. Yes. While Staff agrees with PGE's decision to move the site of its core operations, Staff believes there may have been some costs that could have been better managed.

Q. Why do you believe IOC costs could have been better managed?

A. **[BEGIN CONFIDENTIAL]** [redacted][17] [redacted][18] **[END CONFIDENTIAL]** Based on discovery retrieved from PGE, there appear to

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14 PGE/800, Bekkedahl-Jenkins/13-14.
15 PGE/802.
16 PGE/800.
17 Staff/703, PGE Response to Staff DR 880.
18 Staff/703, PGE Response to Staff DR 880.

be other costs associated with the IOC in addition to this number, which are collectively larger and are highlighted in blue below:[19]

Table 2 - Itemized Breakdown of IOC Costs

Integrated Operations Center (IOC)	
Charge	**Cost**
Outside Services	167,430,228
Materials	30,992,752
AFUDC	12,502,531
Internal Labor (Loaded)	2,253,598
Taxes & Fees	1,926,027
Non-Labor Overheads	63,334
Software	30,000
Other Business Expenses	5,540
Total	**215,204,009**

The total for these more direct costs is roughly $198.4 million. Based on review of the PJF, this does not appear to include loaded costs and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

While it is not uncommon for project cost estimates to change as more details are known about a particular project, and while there are many different components to building a substantive project like the IOC, the PJFs do not provide insight into the planning and budgeting of these costs. While Staff asked for original budgets and cost tracking, Staff did not receive this data in time to include in this testimony. As a result, Staff was unable to verify whether these differences in costs were due to valid planning

[19] Staff/702, PGE Response to Staff DR 326.

changes, or whether these were additional costs allocated into the budget that merit additional review.

Q. What is your proposed adjustment?

A. Based on the fact that Staff was only able to verify cost control for the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in what appears to be total (e.g., including loadings) costs of the project, Staff is proposing to split the difference between what has been proposed in PGE's testimony ($215.2 million) and the number Staff was able to identify as the initial total cost projection, **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** This results in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and because it is listed as one lump sum in PGE's response to Staff DR 311, Staff interprets this to mean all or most of this number includes direct costs and does not provide a loaded adjustment.

Staff invites PGE, in its Reply Testimony, to address the issue of discrepancies in cost planning and cost controls as it pertains to the IOC. It is essential for the Company to reassure the Commission and Staff of its planning process, that it clearly maps out how these project cost estimates have changed, and specifically, where budgets may have increased, and if so, why.

Butler Substation

Q. Please describe your review of the Butler Substation project.

A. I collaborated with Staff's safety electrical engineer and rates division to analyze PGE's investment. Staff reviewed various white papers pertaining to growth in the Hillsboro area and need for expansion,[20] along with PJFs[21] and discovery related to the Butler substation located in the Hillsboro area.

Q. Do you have any concerns with the construction of this project?

A. Yes. [**BEGIN CONFIDENTIAL]** [redacted].[22] [**END CONFIDENTIAL]** However, in an exhibit to its testimony, PGE states that the Butler Substation provides transmission system flexibility and increases reliability for all customers in the area served by the substation.[23] It is unclear to Staff whether **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

The Company was unable to produce white papers on the need for the Butler substation because this project was "expedited."[24] As a result, Staff

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20 Staff/705 and Staff/706, Confidential exhibit on Hillsboro Reliability Project and Highly Confidential Exhibit on Horizon VWR3 Project.
21 Staff/704.
22 Staff/704.
23 PGE/801, Bekkedahl-Jenkins/1.
24 Staff/702, PGE Response to Staff DR 334.

believes that the Company should explain how it will recover the costs of the project (i.e., explain whether the substation is **[BEGIN CONFIDENTIAL]** [redacted]

Q. [redacted] **[END CONFIDENTIAL]**

A. Yes. **[BEGIN CONFIDENTIAL]** [redacted].[25] [redacted] **[END CONFIDENTIAL]** Given this general risk, Staff believes it is particularly important that the Company justify the Butler substation load in its Reply Testimony and explain how it will benefit all ratepayers.

Q. Do you have any concerns with the costs or cost management of this project?

A. While Staff could not immediately identify any clear evidence of overruns or mismanagement that would be an unfair burden to customers, the PJFs for this project did not contain much information to help Staff verify prudent management of costs. Further, as this was an expedited project, it is unclear how timing played a role in costs. Staff is still reviewing the project and waiting on additional discovery not received in time for this testimony.

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[25] Staff/703, PGE Response to Staff DR 876.

Staff reserves the right to provide additional adjustments upon receiving PGE's arguments in Rebuttal Testimony.

<u>Harborton Reliability Project Phase I</u>

Q. Please describe your review of the Harborton Reliability Project Phase 1 ($56.1 million).

A. I collaborated with members of Staff's safety and rates divisions to analyze PGE's investment. Staff reviewed a white paper pertaining to the Harborton Reliability Project and need for expansion,[26] along with PJFs[27] and discovery related to the project. PGE indicates that this project is intended to rebuild the 115kV yard at the Harborton substation to enhance system reliability.[28]

Q. Do you have any concerns with PGE proceeding with construction of this project?

A. In general, no. Upon collaborative review with safety Staff, the project seems to be supported by load forecasts that support the transmission expansion.

Q. Do you have any concerns with the costs or cost management of this project?

A. Yes. There are budget increases in 2019 and throughout the PJF for this project for reasons that are not well explained. The PJF states, **[BEGIN CONFIDENTIAL]** [redacted]

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26 Staff/705, Confidential white paper on Harborton Reliability project.
27 Staff/704.
28 Staff/702, PGE Response to Staff DR 142.

[redacted]”[29] [redacted], [redacted][30] [redacted] **[END CONFIDENTIAL]**

Based on the ambiguous information provided, it was not possible to determine the real reason for the cost increase. The PJFs do not provide sufficient clarity into cost increases and decreases, and what project changes they map to. Further, the change orders only provided the budget impacts associated with **[BEGIN CONFIDENTIAL]** [redacted].[31]

[redacted][32] **[END CONFIDENTIAL]**

Q. Do you have any other concerns with the costs or cost management of this project?

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29 Staff/704.
30 Staff/703, PGE Response to Staff DR 667.
31 Staff/703, PGE Response to DR 667, Attachment (change orders for Harborton Reliability Project).
32 Staff/704.

A. Yes. Staff is concerned about the overall project cost. The PJF states, **[BEGIN CONFIDENTIAL]** [redacted][33] [redacted][34] [redacted][35] **[END CONFIDENTIAL]** This is a project that should be flagged for review in PGE's next rate case.

Q. What is your recommended adjustment?

A. Due to the ambiguity of the change orders and the PJFs, Staff cannot verify prudent management of costs. As a result, Staff's recommendation is to disallow all the cost increases identified, which in total, amounts to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In its Reply Testimony, the Company should clarify these ambiguities.

<u>**Blue Lake Phase II Project**</u>

Q. Please describe your review of the Blue Lake Phase II Project ($36.9 million).

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33 "[redacted]"

34 Staff/704.

35 Staff/703, PGE Response to Staff DR 668.

A. I collaborated with members of Staff's safety and rates divisions to analyze PGE's investment. Staff reviewed a white paper pertaining to the Blue Lake Phase II Project and need for expansion,[36] along with PJFs[37] and discovery related to the project. The Company explains that this project installed additional equipment at the Blue Lake substation, including a new bulk power transformer and switchgear at the Blue Lake substation.[38]

Q. Do you have any concerns with the construction of this project?

A. In general, no. Upon collaborative review with safety Staff, the project seems to be supported by load forecasts that support the transmission expansion.

Q. Do you have any concerns with the costs or cost management of this project?

A. Yes. There appear to be cost increases, and the PJF is unclear about whether this was due to a contractor oversight, and therefore passed along costs to PGE. The cost increases appear to be caused by **[BEGIN CONFIDENTIAL]** [redacted].[39] **[END CONFIDENTIAL]**

Q. What is your recommended adjustment?

[36] Staff/705, Confidential white paper on Blue Lake Phase II project.
[37] Staff/704.
[38] Staff/702, PGE Response to Staff DR 142 and PGE/801, Bekkedahl – Jenkins/3.
[39] Staff/704.

A. Due to the ambiguity of the change orders[40] and the PJFs, Staff cannot verify prudent management of costs. As a result, Staff's recommendation is to disallow all the cost increases identified, which amount to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In its Reply Testimony, the Company should clarify these ambiguities.

<u>**Helvetia Substation Project**</u>

Q. Please describe your review of the Helvetia Substation Project ($22.5 million).

A. I collaborated with Staff's safety electrical engineer and rates division to analyze PGE's investment. Staff reviewed various white papers pertaining to growth in the Hillsboro area and need for expansion,[41] along with PJFs[42] and discovery related to the Butler substation located in the Hillsboro area. PGE explains that this project was implemented to serve industrial load growth in the North Hillsboro area.[43]

Q. Do you have any concerns with the construction of this project?

A. Yes. Staff does not have an issue with the need for this project based on industrial growth in the Hillsboro area.[44] This particular substation was primarily triggered by **[BEGIN CONFIDENTIAL]** [redacted]

40 Staff/703, PGE Response to Staff DR 627.
41 Staff/705 and Staff/706.
42 Staff/704.
43 Staff/702, PGE Response to Staff DR 142.
44 Staff/705 and Staff/706.

[redacted][45] **[END CONFIDENTIAL]** However, like the Butler substation project, the Helvetia substation project is unique because the Company was unable to produce white papers on substation need because they were "expedited."[46]

Q. How will this project be financed?

A. **[BEGIN CONFIDENTIAL]** [redacted].[47] [redacted]

Q. [redacted]

A. [redacted]. **[END CONFIDENTIAL]** In its Reply Testimony, the Company should clarify the circumstances surrounding the financing of this project and explain how including it in the rate case will benefit all ratepayers.

Q. Do you have any concerns with the costs or cost management of this project?

45 Staff/704.
46 Staff/702, PGE Response to Staff DR 334.
47 Staff/703, PGE Response to Staff DR 682 and Staff/704.

A. The PJFs for this project did not contain much information to help Staff verify prudent management of costs. Further, as this was an expedited project, it is unclear how timing played a role in costs, in addition to the financing issues discussed above. Staff is still reviewing the project and reserves the right to provide additional adjustments upon receiving PGE's arguments in Rebuttal Testimony.

Rock Creek Substation

Q. Please describe your review of the Rock Creek Substation ($21.2 million).

A. I collaborated with Staff's safety electrical engineer and rates division to analyze PGE's investment. Staff reviewed a white paper pertaining to the Rock Creek Substation Project and need for expansion,[48] along with PJFs[49] and discovery related to the project.

Q. Do you have any concerns with the construction of this project?

A. In general, no. Upon collaborative review with safety Staff, the project seems to be supported by load forecasts that support the transmission expansion.

Q. Do you have any concerns with the costs or cost management of this project?

A. Yes. There appear to be cost increases, and the PJF is unclear about whether this was due to a contractor oversight. The direct causes of the

[48] Staff/705.
[49] Staff/704.

cost increases appear to be **[BEGIN CONFIDENTIAL]** [redacted][50] [redacted][51] [redacted][52] **[END CONFIDENTIAL]**

Q. What is your recommended adjustment?

A. Due to the ambiguity of the change orders and the PJFs, Staff cannot verify prudent management of costs. As a result, Staff's recommendation is to disallow all the cost increases identified, which amounts to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. In its Reply Testimony, the Company should clarify these ambiguities.

<u>Roseway Substation Project</u>

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[50] Staff/704.
[51] Staff/704.
[52] Staff/704.

Q. Please describe your review of the Roseway Substation Project ($20.3 million).

A. I collaborated with Staff's safety electrical engineer and rates division to analyze PGE's investment. Staff reviewed a white paper pertaining to the Roseway Substation Project and need for expansion,[53] along with PJFs[54] and discovery related to the project.

Q. Do you have any concerns with the construction of this project?

A. In general, no. Upon collaborative review with safety Staff, the project seems to be supported by load forecasts that support the transmission expansion.

Q. Do you have any concerns with the costs or cost management of this project?

A. Yes. There appear to be various cost increases. This seems to be partially because **[BEGIN CONFIDENTIAL]** [redacted][55] [redacted]

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53 Staff/705.
54 Staff/704.
55 Staff/704.

[redacted] **[END CONFIDENTIAL]**

Q. What is your recommended adjustment?

A. Due to the ambiguity of the PJFs, Staff cannot verify prudent management of costs. As a result, Staff's recommendation is to disallow all the cost increases identified, which amounts to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** In its Reply Testimony, the Company should clarify these ambiguities.

<u>**McGill Substation Project**</u>

Q. Please describe your review of the McGill Substation Project ($20.3 million).

A. I collaborated with Staff's safety electrical engineer and rates division to analyze PGE's investment. Staff reviewed a white paper pertaining to the

McGill Substation Project and need for expansion,[56] along with PJFs[57] and discovery related to the project. PGE explains that the McGill Substation was expanded to serve load growth in the area.[58]

Q. Do you have any concerns with the construction of this project?

A. In general, no. Upon collaborative review with safety Staff, the project seems to be supported by load forecasts that support the transmission expansion.

Q. Do you have any concerns with the costs or cost management of this project?

A. The PJFs for this project were particularly ambiguous, such that a clear line between planning and execution was difficult to determine. Staff identified a potential reference to construction beginning in **[BEGIN CONFIDENTIAL]** [redacted]

[56] Staff/705.
[57] Staff/704.
[58] Staff/702, PGE Response to Staff DR 142.

[redacted] **[END CONFIDENTIAL]**

Q. What is your recommended adjustment?

A. Due to the ambiguity of the change orders and the PJFs, Staff cannot verify prudent management of costs. As a result, Staff's recommendation is to disallow all the cost increases identified, which amounts to **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** In its Reply Testimony, the Company should clarify these ambiguities.

<u>Horizon VWR3 Project</u>

Q. Please describe your review of the Horizon VWR3 Project ($9.1 million).

A. I collaborated with Staff's safety electrical engineer and rates division to analyze PGE's investment. Staff reviewed a white paper pertaining to the Horizon VWR3 Project and need for expansion,[59] along with PJFs[60] and discovery related to the project.

Q. Do you have any concerns with the construction of this project?

A. In general, no. Upon collaborative review with safety Staff, the project seems to be supported by load forecasts that support the transmission expansion.

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59 Staff/706, Highly Confidential white paper on Horizon VWR3 Project.
60 Staff/704.

Q. Do you have any concerns with the costs or cost management of this project?

A. Yes. While Staff could not identify any clear evidence for overruns or mismanagement that would be an unfair burden to customers, the PJF for this project were particularly ambiguous and vague. More importantly, the cost of this project appears to have been misrepresented in PGE's testimony.[61] In testimony PGE represented the cost of this project was $13.3 million. Based on PGE's Response to DR 311, and the relatively low cost based on information obtained through the PJF, the cost of this project actually appears to be $9.1 million.[62]

Q. What is your recommended adjustment?

A. Staff's recommendation is to disallow the $4.2 million dollar difference if costs have been misrepresented in the Company's testimony. Because the project cost in DR 311 is only $9.1 million, it is likely this was a typographical error. In its Reply Testimony, the Company should clarify any cost errors in its Opening Testimony, the PJF, and DR 311.

<u>Transmission Line Clearance Mitigation</u>

Q. Please describe your review of the Transmission Line Clearance Mitigation project ($9.6 million).

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61 PGE/801, Bekkedahl – Jenkins / 9.
62 Staff/702, PGE Response to Staff DR 311.

A. I reviewed the PJFs and submitted discovery on the project. The Company explains that this project will design and install replacement for transmission poles that have identified clearance violations.[63]

Q. Do you have any concerns with the construction of this project?

A. The Company indicated that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Staff agrees that, in general, the Company should be addressing these clearance violations.

Q. Do you have any concerns with the costs or cost management of this project?

A. Staff could not identify any clear evidence of overruns or mismanagement that would be an unfair burden to customers. However, the PJFs for this project were particularly ambiguous and vague. Though Staff has no adjustment recommendations for this project, Staff is still reviewing the project and reserves the right to provide additional adjustments upon receiving PGE's arguments in Rebuttal Testimony.

<u>**Horizon Phase II**</u>

Q. Please describe your review of the Horizon Phase II project (13.3 million).

A. I collaborated with Staff's safety electrical engineer and rates division to analyze PGE's investment. Staff reviewed a white paper pertaining to the

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[63] Staff/702, PGE Response to Staff DR 143.

Horizon Phase II Project and need for expansion,[64] along with the PJF[65] and discovery related to the project. The Company explains that this project will install a second bulk power transformer at the Horizon substation to accommodate load growth in the Hillsboro area and maintain compliance with the NERC TPL standards.[66] **[BEGIN CONFIDENTIAL]** [redacted][67] **[END CONFIDENTIAL]**

Q. Do you have any concerns with the construction of this project?

A. In general, no. Upon collaborative review with safety Staff, the project seems to be supported by load forecasts that support the transmission expansion.

Q. Do you have any concerns with the costs or cost management of this project?

A. Yes. Staff has several concerns with the cost tracking of this project. First, the PJF for this project was ambiguous in that a clear construction start time was not intuitive to determine. Staff identified a potential reference to construction beginning in **[BEGIN CONFIDENTIAL]** [redacted][68] [redacted]

64 Staff/705, Confidential white paper on Horizon Phase II project.
65 Exhibit Staff/704.
66 Exhibit Staff/702, PGE Response to Staff DR 142.
67 Staff/703, PGE Response to Staff DR 705.
68 Staff/704.

[redacted][69] [redacted] **[END CONFIDENTIAL]**

Q. What is your recommended adjustment?

A. Because it seems there is a reliability need for this project, Staff does not think it appropriate to disallow it outright. However, due to the many ambiguities in costs surrounding this project, Staff's recommendation is to disallow the **[BEGIN CONFIDENTIAL]** [redacted]

[69] Staff/703, PGE Response to Staff DR 695.

[redacted] **[END CONFIDENTIAL]**

Round Butte Transmission Upgrades Project

Q. Please describe your review of the Round Butte Transmission Upgrades Project ($11.8 million).

A. I collaborated with Staff's safety electrical engineer and rates divisions to analyze PGE's investment. Staff reviewed a white paper pertaining to the Round Butte Transmission Upgrades Project and need for expansion,[70] along with its PJF[71] and discovery related to the project. The Company explains that this project will replace aging and error-prone equipment and install new protective devices to increase system reliability.[72]

Q. Do you have any concerns with the construction of this project?

A. In general, no. Based on Staff's review, the project seems to be supported by load forecasts that support the transmission expansion.

Q. Do you have any concerns with the costs or cost management of this project?

A. Yes. Despite the ambiguity of the PJFs, Staff was able to identify significant cost increases during this project due to **[BEGIN CONFIDENTIAL]** [redacted]

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70 Staff/705, Confidential white paper on Round Butte Transmission Upgrades Project.
71 Staff/704.
72 Staff/702, PGE Response to Staff DR 142.

[redacted][73] [redacted][74] [redacted]

[END CONFIDENTIAL]

Q. What is your recommended adjustment?

A. **[BEGIN CONFIDENTIAL]** [redacted]

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[73] Staff/703, PGE Response to Staff DR 699.
[74] Staff/703, PGE Response to Staff DR 699.

[redacted]

[END CONFIDENTIAL] Staff believes it would be fair and reasonable to split the difference. As a result, Staff's recommended disallowance is **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**

<u>Reconductor Murrayhill-St Marys</u>

Q. Please describe your review of the Reconductor Murrayhill-St Marys project ($7.9 million).

A. I reviewed the PJFs and submitted discovery on the project. There was no white paper associated with this project, and the Company did not provide any documentation explaining project need from an electrical standpoint, though Staff had requested it.[75] The Company explains that this project will reconductor the existing Murrayhill-St Mary's 230kV transmission line to increase the reliability of PGE's transmission system through improvement of the summer rating of the line by over 300 MW.[76]

Q. Do you have any concerns with the construction of this project?

A. The Company indicated that **[BEGIN CONFIDENTIAL]** [redacted]

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[75] Staff/702, PGE Response to Staff DR 527, Update.
[76] Staff/702, PGE Response to Staff DR 143.

[redacted].[77] **[END CONFIDENTIAL]** Although Staff agrees that, in general, the Company should be meeting reliability standards, Staff cannot make a recommendation on need at this time due to limited evidence provided by the Company. The Company should elaborate upon project needs in its Reply Testimony.

Q. Do you have any concerns with the costs or cost management of this project?

A. Based on information provided in response to Staff DR 143, Staff believes there is a risk this project will not be in service by April 2022. Further, though Staff could not identify any clear evidence for overruns or mismanagement that would be an unfair burden to customers, the PJFs for this project were thin and ambiguous. Although Staff has no adjustment recommendations for this project, Staff is still reviewing the project and reserves the right to provide additional adjustments upon receiving PGE's arguments in Rebuttal Testimony. Further, because this project may not reach an in-service date by April 2022, Staff is requesting an Officer Attestation for this project, in addition to a cost cap based on the cost of this project as presented in testimony.

Transmission Full Pole Inspect & Replace

Q. Please describe your review of the Transmission Full Pole Inspect & Replace ($7.6 million) project.

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[77] Staff/704.

A. I reviewed the PJFs and submitted discovery on the project. The Company explains that this project involves inspection and replacement of failed transmission poles to maintain system reliability.[78]

Q. Do you have any concerns with the construction of this project?

A. The Company indicated that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Staff agrees that, in general, the Company should be proactively addressing the safety issue of failed poles.

Q. Do you have any concerns with the costs or cost management of this project?

A. Staff could not identify any clear evidence for overruns or mismanagement that would be an unfair burden to customers. However, the PJFs for this project were particularly ambiguous and vague. Though Staff has no adjustment recommendations for this project, Staff is still reviewing the project and reserves the right to provide additional adjustments upon receiving PGE's arguments in Rebuttal Testimony.

<u>Rebuild Grizzly-RB 500kV Towers</u>

Q. Please describe your review of the Rebuild Grizzly-RB 500kV Towers ($6.9 million) project.

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[78] Staff/702, PGE Response to Staff DR 143.

A. I reviewed the PJFs and submitted discovery on the project. The Company explains that this project **[BEGIN CONFIDENTIAL]** [redacted][79] **[END CONFIDENTIAL]**

Q. Do you have any concerns with the construction of this project?

A. No. Based on the circumstances, Staff agrees with the Company's decision to pursue the project.

Q. Do you have any concerns with the costs or cost management of this project?

A. Staff could not identify any clear evidence for overruns or mismanagement that would be an unfair burden to customers. However, the PJF provided does not include very much cost information on the project.[80] Though Staff has no adjustment recommendations at this time, Staff is still reviewing the project and reserves the right to provide additional adjustments upon receiving PGE's arguments in Rebuttal Testimony.

St. Marys Battery Addition

[79] Staff/703, PGE Response to Staff DR 718.
[80] Staff/704.

Q. Please describe your review of the St Marys Battery Addition ($6.4 million) project.

A. I collaborated with Staff's safety electrical engineer and rates division to analyze PGE's investment. Staff reviewed a white paper pertaining to the St. Mary's Battery Addition Project and need for expansion,[81] along with the PJF[82] and discovery related to the project. The Company explains that this project upgrades system protection at St. Mary's West Substation to prevent several large customers from experiencing sustained load loss during summer peak conditions.[83]

Q. Do you have any concerns with the construction of this project?

A. In general, no. Upon collaborative review with safety Staff, this project seems to be supported by the analysis. The Company indicates that **[BEGIN CONFIDENTIAL]** [redacted].[84] **[END CONFIDENTIAL]**

Q. Do you have any concerns with the costs or cost management of this project?

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81 Staff/705, Confidential white paper on St. Marys Battery Addition.
82 Staff/704.
83 Staff/702, PGE Response to Staff DR 143.
84 Staff/704.

A. Staff could not identify any clear evidence for overruns or mismanagement that would be an unfair burden to customers. However, the PJF the Company provided does not include very much cost information on the project.[85] Though Staff has no adjustment recommendations at this time, Staff is still reviewing the project and reserves the right to provide additional adjustments upon receiving PGE's arguments in Rebuttal Testimony.

T&D Major System Inspect, Replace

Q. Please describe your review of the T&D Major System Inspect, Replace ($156.4 million) project.

A. I collaborated with Staff's safety and rates divisions to analyze PGE's investment. This is a blanket transmission project part of PGE's FITNES (Facilities Inspection and Treatment to the National Electrical Safety Code) program.[86] The program aims to inspect 10 percent of poles and related overhead facilities every year. A rotation of 10 years means that 100 percent of poles and related facilities should be inspected every decade.[87]

Q. Do you have any concerns with the construction of this project?

A. No. The program is designed to meet NESC codes for safe maintenance of transmission poles and related facilities, as well as OAR 860-024-0011 and OAR 860-024-0012.

Q. Do you have any concerns with the costs or cost management of this project?

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85 Staff/704.
86 Staff/702, PGE Response to Staff DR 143.
87 PGE / 810, Bekkedahl - Jenkins / 36.

A. PGE indicates that the FITNES program has identified **[BEGIN CONFIDENTIAL]** [redacted].[88] [redacted]

Table 3 - Average Cost of Pole Inspection[89]

	Close to Plant	Pole Count	Average
2019	$ 30,197,150.53	[redacted]	[redacted]
2020	$ 31,945,591.27	[redacted]	[redacted]
2021	$ 51,052,890.12	[redacted]	[redacted]
2022	$ 43,258,296.00		

[redacted] **[END CONFIDENTIAL]** Staff is still reviewing the

88 Staff/703, PGE Response to Staff DR 615.

89 Calculations derived from PGE's Responses to AWEC DR 006 and Staff DR 615. See Staff/702 and Staff/703.

costs of this project, but in its Reply Testimony, the Company should explain if costs have gone up for this program and why.

In theory, the better the inspectors, the more corrections, and a more resilient system. However, this also likely means higher costs. It is also not clear how these costs correspond to the previous ten-year cycle's average cost per pole. The PJF for this project is not useful for identifying issues related to cost overruns. As explained towards the beginning of this testimony, the PJFs are ambiguous and are only a documentation of capital funding changes, and do not provide much detail into costs. While the cost increases over time are tracked, specifics are not given.

Staff invites PGE to address the issue of increasing costs for the FITNES program in the Company's Reply Testimony. The Company ought to explain whether costs have increased over the past ten years, and why.

Though Staff has no cost adjustment recommendations at this time, Staff is still reviewing the project and reserves the right to provide additional adjustments upon receiving PGE's arguments in Rebuttal Testimony.

FERC RATE CASE AND OTHER REVENUES

Q. Are you addressing all issues associated with Other Revenue in this general rate case?

A. No. I am only addressing transmission wheeling revenue and related cash flows herein. See Exhibit Staff/1300, Zarate for discussion of other aspects of Other Revenue.

Q. Please describe this issue.

A. PGE is preparing to file a transmission rate case (TRC) at FERC, which is different from its general rate case (GRC) in Oregon. It is Staff's understanding that PGE has not filed a TRC with FERC in 20 years. As a result of inevitable changes in its transmission rates, PGE is requesting that the Oregon Commission authorize a deferral of all incremental revenue associated with the final FERC-approved rates. PGE proposes that the deferral would: 1) be subject to an automatic adjustment clause; 2) be effective as specified in the applicable FERC order; and 3) continue until PGE's next GRC (with the deferral to be re-authorized annually). PGE would incorporate the updated transmission revenue in the forecast for Other Revenue.

Q. Does PGE forecast any of these potential new revenues in this GRC?

A. No. It is Staff's understanding that current impacts of the FERC TRC, including impacts to Other Revenues, are not included in the Oregon GRC because PGE has not yet filed at FERC. When Staff asked PGE if it had potential estimates, PGE stated that it did not.[90]

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[90] Staff/702, PGE Response to Staff DR 509.

Q. What is the range of times that PGE transmission rates would go into effect based on the FERC TRC?

A. It is Staff's understanding that FERC has a choice of process and could allow rates to go into effect as soon as 60 days after PGE files its TRC with FERC, and up to five months to allow for more extensive proceedings. In either scenario, FERC may allow revised PGE transmission rates to go into effect immediately at the end of one of these timelines.

Q. Can PGE immediately determine the impact on other revenue for Oregon PGE utility customers?

A. No. It is Staff's understanding that PGE will have to track revenues and retroactively credit transmission customers back any reduction in authorized rates after all subsequent process, including rehearing or reconsiderations, are concluded.

Q. What protects PGE's Oregon utility ratepayers from any mismatch in timing between a TRC and an Oregon GRC?

A. As noted above, PGE has committed to defer additional revenues that result from the TRC.[91]

Q. Does Staff have any concerns with PGE's approach?

A. No. Staff believes PGE's deferral proposal is reasonable.

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[91] See also Order No. 19-400, page 5.

RECLASSIFICATION UPDATE

Q. Please describe this issue.

A. In Docket No. UM 2031, PGE filed to reclassify certain assets from distribution to transmission. Order No. 19-400 highlights the method through which PGE would reclassify future assets:

> A. Radial lines both to distribution and to customers tend to be distribution, but radial generation tie facilities tend to be transmission for accounting purposes but should be classified as production for ratemaking purposes;
>
> B. Non-radial line segments of 100 kV or higher voltage tend to be transmission;
>
> C. Transformers with a secondary voltage under 100 kV tend to be distribution; and
>
> D. Substation assets (e.g., circuit breakers) that are part of the path that connects the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are considered transmission.

For joint use substations, parties stipulated that common assets were allocated between transmission and distribution based on a ratio of the original cost of the transmission and distribution assets in that substation. For substations with both transmission and distribution assets that did not meet the three or more test, the common assets remain classified as distribution. [92]

Q. Did PGE follow this approach?

A. Based on Staff's discovery, yes.[93]

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[92] Order No. 19-400.
[93] Staff/702, PGE Responses to Staff DR 508 and DR 532.

Q. What effects did this reclassification have?

A. Theoretically speaking, it would have increased PGE's Residential Exchange (Res-X) benefits. Res-X is the Residential Exchange Program administered by the Bonneville Power Administration (BPA) to provide residential and small farm customers of Pacific Northwest utilities with access to the benefits of low-cost federal power. Under the program, BPA purchases power from each participating utility at that utility's Average System Cost (ASC). In PGE's case, increasing the amount of transmission assets through reclassification from distribution increased the amount PGE and its customers received in Res-X benefits.[94]

Q. Did PGE have a forecast of Res-X benefits in Docket No. UM 2031?

A. Yes. While it was not a concrete estimate, PGE had calculated a potential benefit of $64.0 million a year.[95]

Q. What are the actual benefits?

A. $63.1 million a year.[96] This is a pass through to customers. While this is important feedback for the Commission, there are many moving pieces in the calculation of residential exchange benefits administered by the Bonneville Power Administration (BPA). Staff has no adjustments on this issue despite actual benefits turning out to be less than those projected.

Q. Have you prepared a table showing all adjustments in your testimony addressing all issues you have written about?

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94 See UM 2031 Joint Staff/100, Muldoon-Hanhan-Rashid/44-50.
95 Staff/702, PGE Response to Staff DR 507 and UM 2031 PGE Response to Staff DR 46.
96 Staff/702, PGE Response to Staff DR 507.

A. Yes. Below is a table representing Staff's adjustments, which totals to $38.8 million.

Project	**Adjustment (millions)**
Integrated Operations Center	[redacted]
T&D Major System Inspect, Replace	TBD
Butler Substation Project	TBD
Harborton Reliability Project Phase 1	[redacted]
Blue Lake Phase II Project	[redacted]
Helvetia Substation Project	TBD
Rock Creek Substation	[redacted]
Roseway Substation Project	[redacted]
McGill Substation Project	[redacted]
Horizon Phase II Project	[redacted]
Round Butte Transmission Upgrades	[redacted]
Trans. Line Clearance Mitigation	TBD
Install Horizon VWR3 Transformer	Verify
Reconductor Murrayhill-St Marys	TBD
Transm Full Pole Inspct & Replace	TBD
Rebuild Grizzly-RB 500kV Towers	TBD
St Marys Battery Addition	TBD
Current Total	**38.8**

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	Nadine Hanhan
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst, Transmission & Distribution Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Arts in Economics, CSUSB (2010) Bachelor of Arts in Philosophy, CSUSB (2010) Master of Science in Applied Economics, Oregon State University (2015)
EXPERIENCE:	I have nine years of utility regulation experience. For four years, I worked at the Citizens' Utility Board of Oregon as a ratepayer advocate for residential customers. While there, I provided analysis, expert testimony, and comments in a variety of dockets with topics including gas and electric integrated resource planning, solar resource value, renewable contribution to capacity, smart grids, power costs, natural gas hedging, and electric vehicles. Cases I worked on at CUB include, but are not limited to: UE 264, UE 296, UM 1505, UM 1657, UM 1667, UM 1675, UM 1716, UM 1719, UM 1746, LC 55, LC 56, LC 57, LC 58, LC 59, LC 60, LC 61, LC 62, and LC 63. For five years I have been employed at the OPUC, where I have provided analysis, testimony, and comments in a variety of dockets and proceedings including smart grids, integrated resource plans, voluntary green energy tariffs, electric vehicles, renewable portfolio standard rules, renewable portfolio standard compliance, certificates of public convenience and necessity, power cost cases, and transmission planning and prudence review, among others. Cases I have worked on at the OPUC include, but are not limited to: ADV 901, AR 609, AR 610, AR 626, AR 638, LC 62, LC 64, LC 68, LC 70, LC 71, LC 73, LC 74, LC 76, PCN 2, PCN 4, UE 347, UE 348, UE 355, UE 374, UE 390, UE 391, UM 1810, UM 1811, UM 1815, UM, 1846, UM 1847, and UM 2031.

CASE: UE 394
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

October 25, 2021

August 24, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 006
Dated August 10, 2021

Request:

Please refer to PGE / 800 Bekkedahl – Jenkins / 4 Table 1. Please provide the following information for each project included in this table with gross plant greater than $1 million:

a. Project number and description;
b. Documents associated with project approval, including approval of any substantial changes;
c. Project management documents;
d. Capital spending by month; and
e. Date and amounts of transfers to plant.

Response:

a. PGE's response to OPUC Data Request No. 198 provides the requested information for certain projects. Attachment 006-A provides the requested information for the remaining projects.
b. PGE's response to OPUC Data Request No. 198 provides the requested information for certain projects. Confidential Attachment 006-B provides the requested information for the remaining projects.
c. PGE's response to OPUC Data Request No. 198 provides the requested information for certain projects. Confidential Attachment 006-B provides the requested information for the remaining projects.
d. Attachment 006-C provides the requested information.
e. Attachment 006-C provides the requested information.

Attachment 006-B contains protected information subject to Protective Order No. 21-206.

Staff/702
Hanhan2

AWEC DR 006 (part d) - Capital Spending by Month
January 2019 through April 2022

Project	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20
P36501 - Integrated Operations Center (IOC)	8 961 696	687 499	340 224	87 298	447 924	3 346 207	(1 342 871)	723 979	5 734 824	(898 728)	7 063 717	2 985 615	4 436 899	1 628 030	4 475 039	5 214 029	4 886 951	5 856 591	7 347 128
P17443 - T&D Major System Inspect Replace	1 911 763	1 647 514	2 003 205	1 964 341	2 773 734	2 141 632	2 966 596	3 139 782	3 132 668	3 337 712	(913 274)	5 658 246	2 106 215	3 249 665	3 701 487	2 618 898	3 829 925	3 5 8 980	2 054 157
P35924 - Distribution System Construction II	2 348 654	4 322 567	5 352 938	3 672 505	4 293 215	5 569 182	3 178 740	2 680 049	4 930 829	3 946 647	4 378 386	6 384 091	3 521 321	5 482 210	6 375 142	3 016 637	5 560 631	5 812 970	3 421 601
P35925 - Dist Customer Line Construction II	2 948 325	3 453 139	3 159 987	3 742 001	3 944 907	5 0 8 6	2 770 247	2 914 676	4 519 495	2 652 662	2 736 364	3 068 811	1 998 519	716 397	2 648 338	2 342 964	3 973 08	2 896 072	2 246 822
P36708 - Butler Substation Construction	-	3 821	55 760	19 153	107 029	25 370	26 855	1 0 477	110 711	113 381	202 704	115 341	628 894	62 669	954 592	11 058 845	6 079 409	0 746 950	13 535 901
P36039 - Harborton Reliability Project PH1	1 759 588	1 799 463	4 217 806	2 493 643	1 9 0 442	2 017 725	173 984	1 705 9 6	1 124 766	2 864 928	(2 228 109)	1 536 123	2 004 580	1 915 589	3 317 638	2 903 85	1 417 009	1 533 2 0	1 078 754
P14628 - Replace Failed Underground Cables	849 757	1 496 095	1 668 430	1 266 07	1 483 653	949 219	1 042 425	1 382 283	1 158 921	1 785 913	1 068 167	1 309 496	2 050 359	1 471 280	1 273 442	971 65	1 533 131	1 711 652	1 712 3 0
P37048 - Outage or Emergency Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36373 - Blue Lake Phase II	248 883	249 019	353 988	748 813	1 325 974	2 559 512	1 972 597	3 972 657	2 704 302	2 571 712	2 254 454	1 233 349	536 690	898 122	736 617	1 510 571	1 525 989	2 173 998	1 278 813
P35679 - Construct Marquam Project	2 080 243	948 511	742 089	199 895	287 378	2 523 6 6	111 655	5 6 385	406 418	247 203	9 775	(286 150)	6 066	5 227	87 044	1 870	-	9 787	73 845
P36537 - Unjacketed Cable Replacement Prgrm	1 114 335	614 232	1 093 502	2 088 429	2 534 2 0	2 575 879	1 460 717	1 857 389	2 440 994	1 057 453	3 640 938	(147 05)	1 834 101	1 574 984	3 478 099	255 805	962 948	903 700	12 932
P36879 - Advanced Distribution Mgt System (ADMS)	-	-	-	-	-	-	-	6 066	2 194 394	68 321	1 783 435	2 345 891	299 129	858 278	1 08 604	1 028 536	954 320	2 775 732	663 7 6
P35890 - Purchase Distribution Transformers	65 737	819 604	1 068 089	405 491	987 324	6 6 463	555 351	788 635	711 147	527 797	750 904	1 235 248	910 246	712 324	777 08	1 279 050	624 686	580 259	1 215 992
P36680 - Brookwood Substation Conversion	-	1 641	175 067	81 980	248 079	155 561	378 715	292 755	374 796	432 541	124 073	1 390 076	297 872	229 457	287 631	828 015	294 035	2 0 193	87 620
P36693 - Helvetia Substation	-	-	-	38 191	56 164	105	7 364	(300 020)	1 918	14 176	(544 124)	860 725	(700 429)	763 288	1 190 989	65 502	151 483	58 684	48 434
P36770 - Street and Area Light Construction	-	-	(2 921)	22 748	145 097	395 602	3 6 267	877 760	441 247	275 696	166 304	533 015	599 303	775 847	830 270	1 065 077	1 200 496	586 383	442 144
P35572 - Build New Rock Creek Substation	512 592	(51 636)	65 956	52 426	252 783	108 903	160 107	514 713	1 136 096	481 703	1 517 579	1 239 959	735 608	1 072 647	1 272 398	933 894	1 329 812	8 0 0 8	295 891
P36270 - Roseway Substation Expansion	(50 569)	296 512	148 898	317 69	2 0 755	479 024	769 212	371 905	687 604	955 464	3 631 235	1 311 744	1 327 252	1 094 471	2 058 08	1 288 321	337 349	208 888	135 8 0
P36861 - Division Transit Project (DTP)	-	-	-	-	-	-	-	231	239	(0)	411 198	211 891	612 224	1 567 883	1 576 514	784 778	1 554 974	1 3 0 504	450 112
P36522 - Distribution Automation	67 272	02 252	154 673	177 500	178 925	253 560	196 982	104 7 6	195 756	98 394	589 192	635 452	166 079	175 534	503 575	121 198	370 484	822 8 8	212 281
P35980 - PCB Transformer Replacement	1 116 127	1 429 564	1 202 323	1 147 904	1 596 8 0	1 1 0 522	1 414 647	1 453 0 0	1 007 725	2 001 388	1 415 094	1 012 895	939 231	881 853	1 209 64	325 286	(294 537)	108 498	(898 723)
P35938 - Field Voice Communications	175 008	1 228 034	1 632 774	(244 293)	385 928	478 126	602 712	349 857	1 289 109	120 686	2 128 524	335 708	130 051	65 601	2 345 528	66 202	618 401	256 439	528 125
P36229 - McGill Sub Capacity Additions	473 629	06 341	508 651	751 508	784 337	407 584	777 5 8	854 897	57 944	114 129	210 254	48 878	2 349	11 873	855	-	-	-	80 615
P36723 - Field Area Network (FAN)	2 885	8 406	116 272	39 462	179 098	284 620	242 582	614 227	276 925	263 434	55 580	648 195	515 214	340 949	442 092	502 220	260 179	225 051	808 305
P35892 - Purchase Customer Meters	282 563	03 653	112 137	604 374	329 085	313 463	303 714	107 994	784 260	147 778	375 853	100 051	179 830	113 476	535 298	237 978	797 538	275 602	406 652
P35802 - Horizon Phase II Project	1 011 193	743 60	247 601	77 877	5 502	491	8 031	4 068	12 777	37 982	3 445	5 684	5 638	640	200	-	-	2 317	-
P35834 - Round Butte Transmission Upgrades	48 443	69 472	124 281	400 780	801 770	1 274 353	581 032	459 197	366 523	510 690	253 414	(237 659)	93 082	(44 022)	93 244	260 320	20 159	25 093	8 133
P36209 - Silverton Capacity Addition	794 570	204 296	1 124 066	672 053	21 400	895 803	450 291	(58 698)	280 866	144 026	140 623	(2 694)	(26 174)	67 293	4 481	862	-	1 173	747
P36391 - Willbridge Station 11kV Conversion	19 088	50 235	70 584	13 083	51 592	8 917	765 443	8 294	482 934	352 242	(120 070)	902 018	(1 580)	120 447	01 704	126 807	334 709	582 263	681 592
P36868 - Shute Capacity Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7 635	6 275
P36913 - Trans. Line Clearance Mitigation	-	-	-	-	-	-	-	-	-	427	2 482	286 137	6 578	10 915	15 620	81 533	210 928	193 2 8	128 255
P36571 - Marquam Radial Feeder Addition	-	-	-	11 333	0 385	3 649	198	4 809	128	3 798	137	128 257	4 370	43 715	54 566	3 480	3 020	2 6 034	3 6 671
P36763 - Install Horizon VWR3 Transformer	-	-	-	-	-	-	-	-	-	185	161	265 052	1 642	1 713	48 735	(42 775)	54 585	98 894	89 767
P36417 - Replace/Rewind Failed Transformers	3 394	3 399	3 421	20 473	189 643	270 739	27 876	8 868	7 749	18 561	48 274	406 736	9 245	11 536	33 326	16 579	17 614	505 471	14 800
P36867 - Remote Disconnect Project	-	-	-	-	-	-	-	-	2 148	2 012	730 501	1 889 905	55 013	77 031	123 028	89 606	257 873	195 6 8	155 389
P36324 - Garden Home Substation Upgrade	317 153	345 855	541 175	699 294	1 115 1 6	464 295	752 143	378 463	39 109	8 833	234 861	110 092	19 979	64 893	1 505	27 001	-	(4 260)	113
P36766 - Remote Sensing Project	-	-	-	-	-	-	5 885	2 137 452	839 252	41 957	986 341	2 121 075	60 974	56 869	70 682	56 69	1 409 970	1 9 260	51 764
P36907 - Reconductor Murrayhill-St Marys	-	-	-	-	-	-	-	-	-	37 183	(1 040)	45 291	74 211	(14 851)	60 069	86 590	74 932	228 851	66 677
P36089 - Transm Full Pole Inspct & Replace	89 179	126 424	126 246	114 005	151 087	364 273	121 798	153 845	107 495	259 771	140 734	140 451	179 060	55 980	31 007	28 257	156 751	120 748	102 7 8
P37062 - Rebuild Grizzly-RB 500kV Towers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1 2 8 797	2 198 703
P36341 - St Marys Battery Addition	18 135	136 681	130 428	122 404	257 367	390 073	180 078	1 172 681	111 051	199 322	33 112	28 415	40 490	33 704	37 276	26 133	13 543	37 435	8 176
P36910 - Outer Div Multi-Modal Safety Proj	-	-	-	-	-	-	-	-	-	-	40 000	94 691	171 624	79 941	110 156	126 907	200 000	221 097	109 903
P37046 - T&D Asset Relocation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36911 - Wildfire Mitigation	-	-	-	-	-	-	-	-	-	-	-	49 820	-	31 773	9 555	21 949	117 621	345 820	63 524
P36545 - Tree Wire Installment Program	122	122	156	84	53 950	219 773	231 568	327 834	1 181	125 493	108 393	383 338	145 951	292 394	288 559	64 908	(3 159)	11 504	1 205
P36470 - Sensus DT34 Meter Exchanges	28 038	44 025	153 172	89 910	329 580	331 825	6 6 224	329 144	841 251	488 121	413 130	443 491	169 750	224 896	378 494	210 464	139 899	113 634	60 6 0
P36450 - Urban Feeder UG Conversion	795 799	544 85	1 129 467	527 395	1 199 147	587 962	613 558	158 185	61 175	2 692	1 457	1 455	3 241	-	-	-	-	(92 711)	-
P36762 - Milliken Tower Reinforcement SE PDX	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	43 002
P36582 - Substation FITNES 2019-2021	4 824	6 969	27 969	64 555	244 822	73 802	80 724	567 579	289 465	294 117	109 796	364 114	162 471	176 863	121 669	230 906	245 414	1 6 426	377 091
P37109 - Customer Data Centers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P18834 - Station E: River District Infrastr	-	2 962	65 488	118 175	191 349	45 411	205 495	35 7 6	988	2 448	100 920	68 385	8 111	112 511	43 052	32 762	(760)	12 812	(283)
P37061 - OH FITNES Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36679 - Orenco Substation 115kV Rebuild	120 320	10 245	10 494	19 677	194 508	159 328	23 928	63 665	14 640	197 780	390 934	390 592	1 028 852	277 448	252 548	1 333 333	1 078 213	869 085	423 4 0
P36439 - Gresham Sub 115kV Rebu ld	-	84 597	42 733	1 679	2 943	225 382	(25 858)	115 585	306 014	276 510	79 577	269 528	79 578	61 094	323 84	268 584	332 433	319 731	235 189
P35908 - SAM: Proactive UG Cable Program	513 800	719 525	533 708	232 945	209 789	237 066	139 656	277 147	253 803	536 683	(574 347)	893 242	14 081	8 136	128 459	86 863	221 524	57 995	1 6 663
P37110 - Restore Bethel-RB 2 0kV Line	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36846 - Intel Water Add and Replace Cables	-	-	-	-	-	2 0 259	2 448 989	1 014 288	329 455	234 811	90 645	(24 602)	7 096	-	(11)	939	(43 767)	933	227
P36334 - Sherwood Security Upgrades	92 372	852 460	625 574	293 084	661 077	171 551	1 641	1 576	228 466	13	53	663	-	-	-	-	-	-	-
P35914 - Substation Fitness 2015-2018	340 871	333 424	145 603	290 726	471 482	386 878	1 0 361	76 224	63 029	20 484	117 068	195 415	160 748	11 963	(11 401)	(809)	1 861	1 068	(304)
P36583 - Strategic Spare Substation Equip	1 547 897	18 638	21 501	-	-	-	54 891	11 472	-	(37 358)	39 173	-	-	-	-	-	-	-	-
P35095 - Dist System Line Construction	6 284	31 606	20 508	8 602	8 892	13 750	115 865	1 6 5 0	36 099	19 107	6 869	(262 787)	1 719	5 261	4 643	7 733	2 615	(499)	456 511
P16567 - T&D System Major Maintenance-UG	41 043	310 066	61 96	127 276	147 885	1 0 209	81 7 9	87 7 6	264 601	430 408	25 744	154 186	126 961	172 737	43 596	31 44	94 897	58 309	47 553
P37047 - Joint Pole Construction	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36388 - Oswego Substation Rebuild	25 925	10 798	7 215	4 263	4 145	3 762	12 451	288 532	595 745	700 908	329 329	747 007	5 003	1 88	(87)	1 067	1 462	491	-
P36056 - Upgrade/Add Revenue Meters	14 399	16 927	27 151	13 796	47 744	74 707	100 809	27 470	66 863	34 323	2 986	1 057	30	4 310	64	(0)	-	-	-
P37143 - Credit Remote Connect Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P35484 - Repl Trans Structures & Insulators	994	89	922	4 696	6 827	2 072	1 739	353	131	104 448	99 203	20 694	2 264	248 684	83 351	11 604	63 516	22 202	2 983
P36543 - PRC-002 Protection Upgrades	74	3 255	329	155	1 028	734	49	3 576	30	535	349	76 669	4 070	9 213	3 031	4 941	14 844	8 655	833
P36645 - DPU Relay Replacement Program	-	-	37	6 60	2 287	48 495	193 532	123 419	289 491	344 018	287 077	269 779	147 030	60 686	(1 090)	11 788	79 653	114 028	92 887
P36175 - Nike Campus UG Primary Service	85 096	(7 662)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36527 - TRIP (TripSaver II) Implementation	50 255	31 872	8 697	159	2 535	70	78	15 435	16 510	88 312	141 055	303 147	54 774	23 057	3 228	38 506	47 504	3 500	3 824
P24723 - Substation Arc Flash Mitigation	16 568	846	15 582	11 374	455	105 0 8	3 145	6 050	2 174	214 558	255 030	327 101	(1 005)	262 591	342 710	89 492	86 275	99 448	62 306
P36937 - North Lombard ODOT Project	-	-	-	-	-	-	-	-	-	-	-	-	40 000	120 000	60 027	141 073	79 973	131 127	(1 434)
P36042 - Tektronix Substation Upgrade	6 893	6 567	7 397	965	2 000	1 501	255 471	105 000	375 939	196 083	18 037	20 119	1 252	6 745	(122)	1 242	(22)	-	-
P36550 - QF Interconnection Costs	(2 195 066)	317 802	(832 08)	66 596	(542 727)	(2 8 214)	127 475	(1 868 312)	(30 967)	477 393	773 240	6 005 342	(5 310 674)	(267 632)	34 686	(92 716)	(739 809)	209 500	367 948
P35846 - CPP Switch Replacement	6 353	28 113	597	25 654	1 146	134 649	1 6	0 593	4 835	(40)	135 571	216 028	2 068	978	-	29 882	1 299	5 286	4 080
P36454 - Substation Rerock - multiple sites	74 831	(3 500)	19 445	70 220	559 750	247 5 0	1 0 319	148 664	114 818	301	154 052	187 604	14 701	273	337	275	233	158	-
P36235 - Install Low OH Services Guarding	47 827	63 130	29 926	60 173	(55 709)	(148 180)	-	33 290	272 591	(35 558)	46 608	(49 28)	11 215	48 480	76 328	(01 590)	20 930	(0 801)	302 5 6
P37103 - ODOT OR213/SE82nd Foster to Lindy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P37114 - Project BaT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36921 - PGE/DTNA HD charging Demonstration	-	-	-	-	-	-	-	-	-	-	-	-	896	5 575	14 83	4 623	73	1 702	6 226
P35556 - Avian Protection Program	38 152	17 02	39 998	16 749	65 494	7 466	539	8 950	22 534	14 541	60 803	74 387	13 627	22 905	15 992	6 727	86 702	45 962	0 772
P14757 - Underground Locating	30 536	49 416	32 661	20 624	129 541	83 397	52 882	43 624	49 077	93 483	56 731	44 125	42 324	36 393	174 777	227 894	159 420	(4 8 191)	(21 812)
P37049 - Line Crew Truck Stock Materials	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36641 - Oil Spill Containment Modifications	-	-	-	-	-	-	-	93 206	127 182	120 700	5 691	160 807	26 498	11 340	(849)	8	(40)	0 290	34 654
P36462 - EV Charging Network Expansion	412	85 987	(1)	4 005	540	268	1	(1)	( )	(2)	(89 876)	-	-	-	6 011	-	-	-	-
P36530 - Substation upgrades for BNRG Solar	(135 371)	57 486	91 643	277 123	2 4 627	255 4 5	63 277	64 1 8	10 582	61 882	26 217	5 611	1 692	980	7 781	(40 803)	1 674	8 264	-
P36551 - Kelley Point Switch Replacement	34 975	147 510	71 332	66 864	46 402	25 797	8 602	(43 378)	34 681	6 727	46 831	16 111	288	-	-	-	-	-	-
P36322 - King City - Substation Upgrades	1 280 643	69 629	379 988	692 673	9 0 771	385 606	1 104 603	687 440	253 402	285 289	315 975	157 777	(59 531)	10 66	13 231	(194)	(213)	(186)	270 880
P35349 - Dist Line Svs - Equip Replacement	22 581	05 117	16 269	55 436	59 763	20 020	40 482	40 480	34 222	14 122	9 415	(452)	3 366	92 233	15 581	61 577	84 090	92 876	21 964
P36710 - Fairview Substation Upgrades	-	-	-	-	-	45	3 750	7 740	1 902	36 777	574	156 920	17 100	155 204	244 223	124 731	60 296	159 696	4 217
P36730 - Harrison Sub Temp H Install SE PDX	-	-	49 851	5 965	31 384	6 765	562	107 568	98 310	80 913	353 772	105 022	195 231	38 781	(7 234)	936	5 054	9 954	4 019
P36497 - 3G Meter Replacement Project	00 256	63 019	76 756	43 620	31 908	133 148	83 220	47 454	117 584	104 565	54 923	67 401	71 288	50 938	14 555	5 633	7 124	9 624	2 529
P35727 - Malin Relay Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Project	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
P36501 - Integrated Operations Center (IOC)	0 208 915	6 108 378	7 552 367	11 393 260	11 515 789	7 137 368	7 130 764	8 750 787	7 219 064	6 850 83	6 988 150	0 857 905	12 549 831	0 842 756	4 208 775	10 988 294	11 104 955	687 047	308 520	228 569	222 544
P17443 - T&D Major System Inspect Replace	1 679 763	680 764	2 746 668	3 211 318	3 079 717	1 235 962	2 498 782	2 274 702	3 546 057	3 908 283	5 047 229	5 614 706	5 662 686	5 902 649	5 738 824	5 716 327	4 978 954	10 814 574	10 814 574	10 814 574	10 814 574
P35924 - Distribution System Construction II	5 5 6 880	(4 872 289)	9 099 236	18 923 762	6 218 971	4 048 655	2 562 82	6 787 763	2 038 643	3 056 710	2 776 080	2 774 785	2 578 062	2 566 764	2 566 123	2 566 112	2 546 802	-	-	-	-
P35925 - Dist Customer Line Construction II	2 775 767	1 651 317	3 486 283	3 499 955	2 805 160	2 346 837	(708 801)	3 173 505	3 900 289	3 465 289	3 471 627	2 887 793	2 280 563	5 789 425	2 664 062	2 375 439	2 305 910	-	-	-	-
P36708 - Butler Substation Construction	5 240 522	5 008 941	3 076 267	3 476 736	1 725 100	1 660 617	417 408	64 510	1 133 556	984 475	464 815	722 548	431 181	660 758	86 993	34 999	33 853	267 547	181 276	82 054	68 685
P36039 - Harborton Reliability Project PH1	649 137	866 424	437 036	216 003	420 833	219 099	379 828	988 631	892 460	205 866	283 360	950 849	943 882	-	-	-	-	-	-	-	-
P14628 - Replace Failed Underground Cables	1 126 132	1 170 584	1 477 077	1 007 977	1 058 129	1 493 158	937 978	1 789 641	1 120 86	1 179 886	1 079 253	1 234 253	1 389 253	1 389 253	1 234 253	1 215 963	1 209 416	-	-	-	-
P37048 - Outage or Emergency Replacement	-	-	-	-	-	3 902 983	29 349 622	5 074 915	1 458 203	1 458 203	1 458 203	1 458 203	1 458 203	1 458 203	1 458 203	1 458 203	1 457 871	-	-	-	-
P36373 - Blue Lake Phase II	1 787 565	1 727 401	787 211	577 530	295 843	599 621	61 506	31 473	68 020	95 664	8 293	22 599	-	-	-	-	-	-	-	151 531	1 206 457
P35679 - Construct Marquam Project	-	-	-	-	42 988	-	711	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36537 - Unjacketed Cable Replacement Prgrm	2 346	(88 232)	349	84 433	18 669	214 151	85 741	401 653	1 03 282	1 009 945	721 440	690 201	-	-	-	-	-	-	-	-	-
P36879 - Advanced Distribution Mgt System (ADMS)	9 0 1 9	1 009 449	1 083 808	1 280 063	1 439 268	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P35890 - Purchase Distribution Transformers	447 172	775 262	390 687	599 465	402 351	564 886	1 220 924	414 414	603 01	607 866	829 727	676 005	701 499	628 775	618 664	728 326	905 846	-	-	-	-
P36680 - Brookwood Substation Conversion	261 781	193 765	414 078	217 223	1 780 375	135 266	310 729	747 807	1 310 579	2 333 883	3 665 444	4 562 743	4 3 6 4 8	1 375 513	1 687 257	519 180	495 942	109 879	109 879	09 879	78 931
P36693 - Helvetia Substation	64 251	12 400	1 300 419	1 175 442	3 653 317	2 884 609	2 07 672	1 878 964	3 65 131	1 821 352	1 179 157	948 1 8	279 379	145 753	35 097	-	-	-	-	-	-
P36770 - Street and Area Light Construction	777 296	377 775	455 894	651 112	693 232	487 803	535 883	415 624	666 566	1 60 62	1 598 1 6	848 231	848 473	849 001	909 372	1 295 853	730 157	-	-	-	-
P35572 - Build New Rock Creek Substation	17 5 0	22 519	18 320	244 255	490 544	44 351	203 828	265 036	(96 784)	91 707	-	-	-	-	-	-	-	-	-	-	-
P36270 - Roseway Substation Expansion	193 567	429 279	214 558	336 657	1 184 876	623 952	294 029	67 886	89 465	-	-	-	-	-	-	-	-	-	-	-	-
P36861 - Division Transit Project (DTP)	680 053	931 111	1 771 521	96 872	2 850 061	156 746	1 146 719	1 587 241	268 720	1 807 795	-	-	-	-	-	-	-	-	-	-	-
P36522 - Distribution Automation	101 702	29 850	68 120	129 899	196 808	342 069	932 564	1 017 068	1 205 441	1 416 959	1 364 028	1 041 576	1 240 290	1 225 856	1 125 711	1 004 194	502 346	-	-	-	-
P35980 - PCB Transformer Replacement	78 0 6	(312 424)	86 440	316 093	193 857	730	2 370	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P35938 - Field Voice Communications	247 478	428 670	333 151	83 810	271 010	(33 892)	02 046	94 255	234 677	116 190	2 806 846	-	-	-	-	-	-	-	-	-	-
P36229 - McGill Sub Capacity Additions	-	(39 926)	-	39 937	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36723 - Field Area Network (FAN)	326 441	271 231	269 401	236 157	374 780	392 431	340 586	896 140	409 990	81 667	248 683	401 760	248 683	293 867	234 224	229 394	224 394	4 020 116	188 116	88 116	88 116
P35892 - Purchase Customer Meters	549 701	692 234	190 761	171 829	532 335	131 534	127 176	948 144	505 154	330 501	3 0 501	3 0 501	166 897	166 897	253 063	330 501	330 501	712 719	712 719	712 719	712 719
P35802 - Horizon Phase II Project	-	3 557	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P35834 - Round Butte Transmission Upgrades	(29 603)	(97 086)	1 092	136 125	29 392	36 030	38 347	378	-	-	-	-	-	-	-	-	-	-	-	-	8 762
P36209 - Silverton Capacity Addition	-	-	-	-	1 805	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36391 - Willbridge Station 11kV Conversion	565 796	1 188 028	1 143 184	383 517	755 144	307 461	97 471	170 741	644 728	689 788	125 205	60 147	3 8 005	349 622	366 110	60 437	26 135	9 781	9 781	9 781	9 781
P36868 - Shute Capacity Addition	2 577	(255)	397	170	224 325	1 882 029	130 929	95 331	141 525	133 895	441 314	3 737 881	1 119 949	150 081	1 409 805	496 035	26 322	-	-	-	-
P36913 - Trans. Line Clearance Mitigation	146 964	247 855	517 076	409 027	491 896	471 935	339 740	252 212	84 676	549 676	913 293	1 247 439	1 092 176	1 014 676	472 176	84 676	22 676	66 667	66 667	66 667	66 667
P36571 - Marquam Radial Feeder Addition	1 012 465	1 858 935	956 253	839 338	1 793 570	552 065	1 074 339	282 035	149 008	143 711	25 5 0	-	-	-	-	-	-	-	-	-	-
P36763 - Install Horizon VWR3 Transformer	2 6 074	5 0 123	1 319 142	494 957	650 907	436 415	378 768	443 808	903 345	637 600	2 559 454	-	-	-	-	-	-	-	-	-	-
P36417 - Replace/Rewind Failed Transformers	406 441	7 800	389 476	40 877	789 143	18 959	32 963	719 129	153 663	699 218	3 781	2 112	287 445	945	25 804	434 005	1 940	961 006	961 006	961 006	913 006
P36867 - Remote Disconnect Project	672 631	94 303	192 138	93 198	106 687	37 624	31 646	973 81	656 570	439 496	126 487	125 487	125 487	125 487	125 487	125 487	125 487	156 228	(568 172)	158 879	158 879
P36324 - Garden Home Substation Upgrade	696	(1 186)	-	166	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36766 - Remote Sensing Project	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36907 - Reconductor Murrayhill-St Marys	35 437	11 667	49 128	59 457	20 902	191 793	29 196	310 432	112 948	219 520	1 032 403	1 465 998	700 184	1 321 261	1 290 460	427 069	45 990	32 231	32 231	32 231	16 115
P36089 - Transm Full Pole Inspct & Replace	182 568	366 044	375 509	225 224	82 686	5 613	38 88	8 62	137 474	04 045	189 446	317 548	402 948	402 808	402 808	317 432	287 481	-	-	-	-
P37062 - Rebuild Grizzly-RB 500kV Towers	2 586 393	1 014 664	345 916	27 472	(31 520)	2 714	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36341 - St Marys Battery Addition	19 752	40 666	32 949	25 185	48 127	39 463	50 852	82 69	12 962	77 404	42 678	387 272	485 974	170 011	164 205	109 555	91 183	211 020	248 327	379 562	02 231
P36910 - Outer Div Multi-Modal Safety Proj	189 424	309 667	580 232	211 308	925 477	1 418 127	139 434	743 446	238 809	-	-	-	-	-	-	-	-	-	-	-	-
P37046 - T&D Asset Relocation	-	-	-	-	-	12 061	(146 889)	(732 255)	842 756	937 338	644 370	820 370	676 239	675 379	675 423	896 530	749 321	2 531	2 531	1 677	823
P36911 - Wildfire Mitigation	32 903	0 482	25 882	19 760	298 601	(36 979)	255 603	816 442	338 326	753 115	487 264	171 535	248 535	619 229	732 709	67 665	53 101	-	-	-	-
P36545 - Tree Wire Installment Program	70 645	(8 399)	203 795	3 427	37 322	77 729	90 264	643 611	912 467	551 739	127 969	271 786	268 756	268 756	606	606	606	-	-	-	-
P36470 - Sensus DT34 Meter Exchanges	56 0 6	(8 967)	71 310	108 723	44 353	10 165	4 03	1 415	-	-	-	-	-	-	-	-	-	-	-	-	-
P36450 - Urban Feeder UG Conversion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36762 - Milliken Tower Reinforcement SE PDX	-	50 178	198 709	132 494	(624)	931	3 767	561 156	43 623	551 663	1 335 078	945 2 0	949 658	1 334 4 8	-	-	-	-	-	-	-
P36582 - Substation FITNES 2019-2021	247 865	224 207	432 143	287 441	486 539	178 927	195 078	284 438	04 510	214 766	519 149	132 400	366 495	527 562	268 265	266 340	458 575	-	-	-	-
P37109 - Customer Data Centers	-	-	-	-	-	-	32 202	(1 238 809)	2 190 570	2 045 159	1 873 795	545 583	-	-	-	-	-	-	-	-	-
P18834 - Station E: River District Infrastr	53 477	(1 781)	1 404	307	(44)	-	-	-	25 925	71 133	35 925	0 508	25 925	25 925	25 925	25 925	25 925	-	-	-	-
P37061 - OH FITNES Transmission	-	-	-	-	-	123	51 584	48 053	416 844	443 194	690 107	687 022	899 961	737 1 8	607 996	340 202	218 414	-	-	-	-
P36679 - Orenco Substation 115kV Rebuild	281 880	397 044	93 392	2 916	55 839	26 791	48 089	25 615	19 471	17 988	13 0 6	0 558	71 349	91 358	58 996	66 586	66 860	360 098	132 840	116 884	14 541
P36439 - Gresham Sub 115kV Rebu ld	294 284	189 772	308 296	428 391	425 705	158 403	(7 857)	7 761	-	-	-	-	-	-	-	-	-	255 898	201 953	235 632	203 510
P35908 - SAM: Proactive UG Cable Program	8 924	(14 594)	2 341	6 440	(1 234)	-	3 489	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P37110 - Restore Bethel-RB 2 0kV Line	-	3 940	102 484	112 500	680 814	86 176	868 245	799 824	621 211	07 896	29 402	22 958	23 0 8	628 986	631 388	7 742	-	-	-	-	-
P36846 - Intel Water Add and Replace Cables	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36334 - Sherwood Security Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P35914 - Substation Fitness 2015-2018	1 2 0	(22 024)	-	20 055	4 840	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36583 - Strategic Spare Substation Equip	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P35095 - Dist System Line Construction	3 393	(5 798)	(3 480 914)	30 427	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P16567 - T&D System Major Maintenance-UG	17 6 0	(8 313)	42 623	68 804	55 911	15 179	44 869	28 789	52 113	59 089	59 089	67 2 0	67 2 0	73 485	116 203	106 051	111 310	-	-	-	-
P37047 - Joint Pole Construction	-	-	-	-	-	427	9 62	(61 739)	1 038 080	09 530	272 625	448 617	406 667	211 729	494 287	433 881	78 634	-	-	-	-
P36388 - Oswego Substation Rebuild	(242)	(103 683)	280	103 683	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36056 - Upgrade/Add Revenue Meters	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P37143 - Credit Remote Connect Meters	-	-	-	-	-	-	-	-	77 446	459 354	498 347	5 0 466	5 0 466	302 307	262 146	262 146	262 146	-	-	-	-
P35484 - Repl Trans Structures & Insulators	75 107	131 4 6	52 801	163 584	66 532	2 869	3 379	10 260	5 87	5 86	643 860	215 404	189 6 0	190 6 0	230 093	229 343	166 518	67	67	67	67
P36543 - PRC-002 Protection Upgrades	1 0 8	659	82 336	56 464	66 515	122 302	75 195	190 453	239 734	152 140	79 481	433 389	1 0 979	274 431	217 465	327 598	190 564	407 068	18 687	2 687	2 687
P36645 - DPU Relay Replacement Program	152 285	41 176	13 610	5 481	4 429	31 459	59 065	50 637	10 232	10 231	123 404	284 221	172 574	173 471	634 787	312 439	234 239	9 733	9 733	9 733	9 733
P36175 - Nike Campus UG Primary Service	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36527 - TRIP (TripSaver II) Implementation	181	876	3 195	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P24723 - Substation Arc Flash Mitigation	24 350	(11 626)	11 398	2 375	6 456	-	-	619	-	-	-	-	-	-	-	-	-	-	-	-	-
P36937 - North Lombard ODOT Project	135 628	348 228	197 766	789 454	246 308	75 325	6 010	(8)	-	-	-	-	-	-	-	-	-	-	-	-	-
P36042 - Tektronix Substation Upgrade	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36550 - QF Interconnection Costs	186 754	(378 846)	763 032	(216 230)	7 283 581	(6 027 892)	83 697	(765 09)	4 476 152	111 940	260 222	284 654	201 782	(748 535)	41 917	39 701	(250 308)	45 767	172 368	172 484	74 561
P35846 - CPP Switch Replacement	4 787	80 475	142 504	95 723	247 336	63 130	9 770	137 680	50 019	50 019	79 932	55 004	40 048	59 990	50 019	35 063	(9 92)	-	-	-	-
P36454 - Substation Rerock - multiple sites	-	-	-	-	-	-	-	-	2 760	41 510	41 5 0	41 5 0	41 5 0	41 5 0	41 510	41 510	23 861	-	-	-	-
P36235 - Install Low OH Services Guarding	3 821	(9 374)	281 697	-	172 567	43 966	56 689	(79 032)	148 358	-	-	-	148 358	-	148 358	-	148 358	-	-	-	-
P37103 - ODOT OR213/SE82nd Foster to Lindy	-	-	-	-	445 001	103 040	06 314	227 532	266 868	330 213	20 720	32 473	6 697	6 697	16 697	16 697	17 249	-	-	-	-
P37114 - Project BaT	-	-	-	-	-	939	1 885	6 639	17 352	89 249	377 374	573 411	474 028	158 471	-	-	-	-	-	-	-
P36921 - PGE/DTNA HD charging Demonstration	194	543 7 0	568 002	6 546	625 719	42 258	11 412	(57 470)	400 682	-	-	-	-	-	-	-	-	-	-	-	-
P35556 - Avian Protection Program	13 379	56 193	74 779	43 729	141 176	41 316	51 870	92 61	34 197	59 357	59 357	59 357	50 057	66 360	50 320	10 947	10 947	-	-	-	-
P14757 - Underground Locating	156 873	91 684	162 818	24 853	(193 197)	24 453	(24 453)	-	34 875	34 875	58 125	8 750	27 125	42 625	34 875	23 250	19 375	-	-	-	-
P37049 - Line Crew Truck Stock Materials	-	-	-	-	-	-	-	202 012	144 585	144 585	144 585	144 585	144 585	144 585	144 585	144 585	144 585	-	-	-	-
P36641 - Oil Spill Containment Modifications	32 505	8 592	9 081	200 050	14 783	950	1 029	9 820	80 501	2 080	2 087	1 497	92 745	2 000	183 838	2 936	92 037	-	-	-	-
P36462 - EV Charging Network Expansion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36530 - Substation upgrades for BNRG Solar	-	-	-	-	34 706	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36551 - Kelley Point Switch Replacement	-	(7 665)	-	7 665	635	-	14 842	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36322 - King City - Substation Upgrades	-	(50 455)	-	50 495	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P35349 - Dist Line Svs - Equip Replacement	62 568	(2 342)	36 688	5 071	64 893	86 100	53 043	111 968	34 225	34 225	50 031	6 860	28 957	39 494	34 225	-	-	-	-	-	-
P36710 - Fairview Substation Upgrades	8 170	(108 192)	10 444	102 575	50 727	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36730 - Harrison Sub Temp H Install SE PDX	140	(3 072)	-	-	4 373	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
P36497 - 3G Meter Replacement Project	1 589	(88 591)	3 194	86 620	(638)	22	(2)	(0)	-	-	-	-	-	-	-	-	-	-	-	-	-
P35727 - Malin Relay Replacement	-	-	-	375 481	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

AWEC DR 006 (part e) - Close to Plant by Month
January 2019 through April 2022

Project	Total Additions	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
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[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	(134)	3 299	79	448 279	22 749	4 390	(1 867)	35 702 278	1 379 858	7 817 923	(723 281)	67 608	532 978	58 117	873 890	(28 351)	(774 242)	164 020	777 0 8	(762 952)	7 805 744	256 929	8 181	1 863 859	-	-	-	-	-	-	-	-
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July 23, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 142
Dated June 24, 2021

Request:

Regarding FERC Form 1, page 216, Construction Work in Process, for the years ended December 31, 2018, 2019, and 2020, for each listed project (>$1 million),

a. Please provide the date the project was placed into service or is expected to be placed into service.
b. Please provide the final cost of the project at the time it was placed into service or the estimated final cost for projects not yet in service.
c. Please provide the FERC account category for each project (Intangible, Steam, Hydraulic, Other Production Plant, Transmission, Distribution, or General).
d. Please provide a brief narrative description of the nature of the project including why it was necessary and how ratepayers will benefit.
e. Please reference the Company's direct testimony and exhibits in this case if applicable.

Response:

Attachment 142-A provides the requested information.

OPUC DR 142

FERC Form 1 Page 216 - CWIP Balances over $1M at Year End 2020

Form 1 Page 216			[a]	[b]	[c]	[d]/[e]
FP#	**Project Description**	**CWIP Balance**	**In-Service Date(s) Month/Year**	**Project Cost**	**FERC Account Category**	**Narrative Description and Reference to Testimony**
P36501	Build Integrated Operations Center	$ 109,122,893	Nov-21	$ 215,204,041	General Plant	Construction of the new Integrated Operations Center (IOC). See Exhibit 800 for specific details.
P36167	Repower Faraday Units 1-5	$ 74,212,574	Mar-22	$ 119,384,638	Hydro Production	The Faraday Repower Project will replace PGE's original Faraday Hydro Plant (units 1 through 5) on the Clackamas River. The new powerhouse will consist of two higher efficiency turbines (Faraday Units 7 and 8) housed in a reinforced concrete structure with new flood protection systems and will result in increased plant reliability and efficiency. See Exhibit 700 for specific details.
P36101	Substation Communication Upgrade	$ 27,560,149	Nov-20 Dec-20 Jul-21 Dec-22	$ 38,336,248	General Plant	This project will replace the communications at all PGE substations with new equipment. This project is in response to telephone companies phasing out the equipment currently in use in 2020, putting at risk the ability to communicate with substations if the current equipment breaks and replacement parts are no longer available.
P36708	Build Butler Substation	$ 18,104,180	Nov-20 Dec-20 Apr-21 Mar-22	$ 72,467,387	Distribution Plant and Transmission Plant	The Butler Substation Project was implemented to serve new industrial load growth in the Hillsboro area. See Exhibit 801 for specific details.
P36270	Roseway Substation Expansion	$ 18,003,672	Feb-21	$ 39,470,327	Distribution Plant and Transmission Plant	The new substation was constructed to serve new load growth in the area, particularly the new South Hillsboro Community ("SoHi"), as well as to improve system flexibility for planned work and unplanned outages. See Exhibit 801 for specific details.
P36879	Advanced Distribution Management System Upgrade	$ 17,488,039	Jul-21 Oct-21 Dec-21	$ 29,708,735	Intangible Plant	ADMS is an operational technology system (software platform) that supports the full suite of distribution management, DA, DER optimization, including predicting, monitoring, controlling, optimizing, and safely operating all elements within a distribution system. ADMS functions being developed by utilities include fault location, isolation and restoration; volt/volt-ampere reactive optimization; conservation voltage reduction; flexible load integration; and support for microgrids and transportation electrification. See Exhibit 800 for details.
P36587	Upgrade Physical Access Control System	$ 12,674,920	Oct-19 Aug-21	$ 16,601,331	Intangible Plant and General Plant	Replacement of PGE's outdated and unsupported physical access control system (AMAG). The new Physical Access Control System will reduce break fix costs and enable PGE to implement higher security access controls.
P36422	Build Evergreen Substation	$ 12,589,326	May-24	$ 15,118,052	Distribution Plant and Transmission Plant	Purchase of land for the new Evergreen substation to increase transmission and distribution system capacity.
P36391	Willbridge Substation Conversion	$ 9,041,729	Dec-20 Aug-21	$ 10,613,244	Distribution Plant	The project rebuilds the Willbridge Substation to address assets past their end of life and to eliminate the non-standard 11kV distribution voltage. See Exhibit 801 for specific details.
P36680	Brookwood Substation Conversion	$ 8,539,069	Dec-21 Apr-22 Jun-22 Jul-22 Aug-22	$ 23,649,922	Distribution Plant	Brookwood Substation was converted to 115kV to provide capacity for existing and future load growth at Brookwood substation. See Exhibit 801 for specific details.
P36693	Build Helvetia Substation	$ 7,918,308	Aug-21	$ 22,449,135	Distribution Plant and Transmission Plant	The Helvetia Substation Project was implemented to serve industrial load growth in the North Hillsboro area. See Exhibit 801 for specific details.
P22449	Colstrip Coal Capital Project	$ 7,858,593	Multiple	$ 40,509,627	Steam Production	This project is for work related to the Colstrip power plant and based on the business plan agreed to by Colstrip's owners of which PGE has 20% ownership.
P36571	Marquam Substation Feeder Addition	$ 7,254,609	Apr-21 May-21 Jul-21	$ 9,483,577	Distribution Plant	This project requests funding to add additional feeder capacity from Marquam Substation to the South Waterfront Region and Marquam Hill. Additional, this project adds Distribution Automation switches in the Marquam Hill in order to mitigate historical outage from Urban Substation's primary feeders and add additional feeder capacity in the Marquam Hill area.
P36134	Hydro Control System Upgrade	$ 7,251,677	Dec-18 - Dec-23	$ 7,637,665	Hydro Production	This project will upgrade the control systems for generation and fish handling facilities at Pelton Round Butte and West Side Hydros. The new systems will be integrated into the plant information system for archiving and data mining of off-normal operating conditions.
P36039	Harborton Reliability Project	$ 7,460,287	Mar-17 - Sep-21	$ 57,148,565	Transmission Plant	Phase 1 of the Harborton Reliability Project rebuilt the 115kV yard to enhance system reliability. See Exhibit 801 for specific details.
P35924	Distribution System Construction	$ 4,357,198	Dec-21	$ 5,777,334	Distribution Plant	Overhead to underground conversion project in support of the Jackson School Road improvement work in Hillsboro.
P36763	Horizon Substation Transformer Installation	$ 3,655,445	May-21 Jun-21 Aug-21	$ 9,101,159	Transmission Plant	The Horizon VWR3 Project installed a bulk power transformer at the Horizon Substation to mitigate overloads on the existing bulk power transformers caused by load growth in the area. See Exhibit 801 for specific details.
P36341	St. Mary's West Substation System Protection Upgrade	$ 3,595,653	Apr-22	$ 6,396,181	Transmission Plant	The project is upgrading system protection at St. Mary's West Substation to prevent several large customers from experiencing sustained load loss during summer peak conditions.
P36829	Build Sherwood Training Center	$ 3,304,414	Oct-21	$ 11,375,085	General Plant	Construction of a training center at Sherwood Line Center to meet training needs for journeymen linemen, pre-apprentices and apprentices.
P36656	Energy Storage System	$ 3,209,071	Oct-21	$ 5,746,647	Other Production	Implement a 2-4 MW Energy Storage system at the Port Westward 2 facility, and integrate the Energy Storage system into the controls for one PW2 unit to leverage the combined resource for spinning reserves.
P36373	Blue Lake Substation Upgrade	$ 3,117,272	Feb-20 Jun-20 Nov-20 Dec-20 Aug-23	$ 37,600,174	Distribution Plant and Transmission Plant	Installation of new bulk power transformers and switchgear. See Exhibit 801 for specific details.
P36617	South Milliken Distribution Line Rebuild	$ 3,011,243	Dec-24	$ 3,928,902	Transmission Plant	The project is replacing the 100 year old 57kV Milliken transmission towers between Faraday and Boring Substations as well as between Boring Substation and Hogan Road in East Multnomah County to eliminate reliability concerns.
P18834	River District Infrastructure - Install Vaults and Conduits	$ 2,947,132	Dec-21	$ 5,162,638	Distribution Plant	Construction of underground conduits and feeders to serve customers in the River District of NW Portland.
P36716	Arleta-Holgate Conversion	$ 2,640,166	Dec-23 Dec-25	$ 3,396,180	Distribution Plant and Transmission Plant	Rebuild the Arleta - Holgate 57kV line to 115kV and convert both Holgate and Arleta Subs from 57kV to 115kV to add capacity for future load growth and improve ability to implement Distribution Automation.
P36378	Centennial Substation Upgrades	$ 2,609,511	Jun-19 Feb-25 Jun-25 Aug-25	$ 8,454,349	Distribution Plant	The Centennial Substation was upgraded to modernize the distribution system and to reduce failure risk.
P24995	Pelton Round Butte Mitigation Enhancement Fund	$ 2,532,257	Multiple	$ 2,532,257	Hydro Production	This project is a requirement of the FERC license for the Pelton Round Butte Project. Completion of the project is necessary for compliance with the terms and conditions of the license relating to mitigation funding. This fund will be used to support resource protection measures for project-related impacts not otherwise covered by specific license conditions, including projects that enhance and improve wetland, riparian, and riverine habitats, and riparian aquatic and terrestrial species connectivity that may be affected by the continued operation of the project.
P36564	Stephens Substation Conversion	$ 2,398,768	Jul-23 Aug-23 Feb-24	$ 2,933,366	Distribution Plant	The Stephens Conversion project will convert the three existing Stephens' 11kV circuits located in Southeast Portland area to 13kV level and add additional capacity at Harrison Substation with new 3 feeder position switchgear to reduce power outages during a peak period.
P36679	Orenco Substation Rebuild	$ 2,208,085	Jun-20 Jun-23 Jul-23 Aug-23	$ 5,084,894	Distribution Plant and Transmission Plant	Rebuild the Orenco substation 115kV and reconductor the Orenco-Sunset 115kV line to reduce seasonal outage risk and accommodate future load growth in the Hillsboro area.
P36550	Small Generator/Qualified Facility (QF) Interconnection	$ 1,938,850	Multiple	$ -	Distribution Plant	The project will track Small Generator/Qualified Facility (QF) interconnection costs associated with engineering studies, construction and contributions in aid of construction. The CWIP balance represents the timing difference between PGE construction spend and receipt of contributions in aid of construction from QF developers.
P35925	Distribution Line Construction	$ 1,882,874	Jul-21	$ 1,847,503	Distribution Plant	Construction of pathway related to new Evergreen Substation project currently under construction (P36422 - Build Evergreen Substation).
P36732	Carty/Boardman Separation Project	$ 1,882,802	May-21 Jul-21 Oct-21 Nov-21	$ 12,494,467	Other Production and Transmission Plant	Separation activites for Carty to become independent from Boardman infrastructure (with the closing of the coal plant), as well as provide alarm monitoring for systems located on the Boardman site from the Carty control room.
P37099	Restore Beaver GT Unit 5	$ 1,815,035	Apr-21	$ 6,041,807	Other Production	The project restored Beaver GT unit 5 to operate following a failure of the third stage buckets in Q1 2020 and expanded capacity to meet Winter 2021 peak loads.
P36973	Upgrade IVR System	$ 1,604,348	Oct-21	$ 1,787,324	Intangible Plant	The project is upgrading the capability of the existing Integrated Voice Response (IVR) system to improve customer experiences and reduce call volumes to the Contact Center through improved system containment.
P36683	Distributed Control Software Upgrade	$ 1,577,547	Nov-20 Dec-21 Dec-22 Dec-23	$ 3,316,449	Other Production	This project is upgrading the devices of the existing distributed control software (DCS) to Windows 10 (or later) to ensure continued support by Microsoft.
P36628	Replace Exhaust Frame and Diffuser	$ 1,558,942	Apr-21	$ 1,849,401	Other Production	The project replaced the exhaust frame and diffuser on Beaver unit 5 to enhance reliability and safety.
P36599	Install Load Bank	$ 1,358,029	Jul-21	$ 3,588,291	Other Production	This project installed a 5MW load bank at Port Westward, which allows blackstart testing without the outages and improves reliability during actual blackstart event by not having to rely on other units for load.
P36417	Replace or Rewind Failed Transformers	$ 1,268,202	Multiple	$ 6,719,217	Distribution Plant	This project establishes a fund to replace or rewind failed substation transformers, so that PGE will be more resilient to a wider variety of disaster scenarios.
P36444	Upgrade Excitation System	$ 1,114,170	Oct-23 Oct-24	$ 3,721,337	Hydro Production	This project will replace the excitation equipment and transformers for West Side Hydro at the Oak Grove, North Fork, Faraday Unit #6, and Rivermill facilities to meet new WECC regulations.
P36582	Canyon Substation Upgrade	$ 1,020,442	Jan-19 - Dec-22	$ 6,884,793	Distribution Plant and Transmission Plant	The project replaced and upgraded obsolete, failure prone and worn out substation equipment to avoid substation equipment failures leading to customer outages.

OPUC DR 142

FERC Form 1 Page 216 - CWIP Balances over $1M at Year End 2019

Form 1 Page 216			[a]	[b]	[c]	[d]/[e]
FP#	**Project Description**	**CWIP Balance**	**In-Service Date(s) Month/Year**	**Project Cost**	**FERC Account Category**	**Narrative Description and Reference to Testimony**
P36039	Harborton Reliability Project	$ 37,708,733	Mar-17 - Sep-21	$ 57,148,565	Transmission Plant	Phase 1 of the Harborton Reliability Project rebuilt the 115kV yard to enhance system reliability. See Exhibit 801 for specific details.
P36167	Repower Faraday Units 1-5	$ 34,748,303	Mar-22	$ 119,384,638	Hydro Production	The Faraday Repower Project will replace PGE's original Faraday Hydro Plant (units 1 through 5) on the Clackamas River. The new powerhouse will consist of two higher efficiency turbines (Faraday Units 7 and 8) housed in a reinforced concrete structure with new flood protection systems and will result in increased plant reliability and efficiency. See Exhibit 700 for specific details.
P36501	Build Integrated Operations Center	$ 28,455,538	Nov-21	$ 215,204,041	General Plant	Construction of the new Integrated Operations Center (IOC). See Exhibit 800 for specific details.
P36373	Blue Lake Substation Upgrade	$ 26,196,691	Feb-20 Jun-20 Nov-20 Dec-20 Aug-23	$ 37,600,174	Transmission Plant	Installation of new bulk power transformers and switchgear. See Exhibit 801 for specific details.
P36101	Substation Communication Upgrade	$ 24,965,674	Nov-20 Dec-20 Jul-21 Dec-22	$ 38,336,248	General Plant	This project will replace the communications at all PGE substations with new equipment. This project is in response to telephone companies phasing out the equipment currently in use in 2020, putting at risk the ability to communicate with substations if the current equipment breaks and replacement parts are no longer available.
P36855	Wheatridge Renewable Energy Facility	$ 17,331,289	Dec-20	$ 150,092,469	Other Production	Project consists of a 300MW wind facility, 50MW solar facility, and a 30MW 4-hr duration energy storage facility, owned by Wheatridge Wind, LLC, a subsidiary of NextEra Energy Resources. 100 MW of the wind resource will be purchased by Portland General Electric(PGE) and the remaining 200 MW will be contracted by PGE for a 30-year term. The solar energy storage facilities will be contracted to PGE under one Power Purchase Agreement (PPA), with a 30-year term for solar and a 20-year term for storage. NextEra will serve as the operator and provide Operations and Maintenance (O&M) for all aspects of the facility with O&M for the 100 MW ownership portion provided under a 30-year agreement.
P22449	Colstrip Coal Capital Project	$ 13,461,228	Multiple	$ 40,509,627	Steam Production	This project is for work related to the Colstrip power plant and based on the business plan agreed to by Colstrip's owners of which PGE has 20% ownership.
P35572	Rock Creek Substation Construction	$ 12,646,409	Dec-20	$ 23,382,993	Distribution Plant	The new Rock Creek Substation was constructed to alleviate heavy loading on the Bethany Substation and serve new load growth in the North Bethany area. See Exhibit 801 for specific details.
P36422	Build Evergreen Substation	$ 12,297,181	May-24	$ 15,118,052	Transmission Plant	Purchase of land for the new Evergreen substation to increase transmission and distribution system capacity.
P35834	Round Butte Transmission Upgrades	$ 11,906,470	Dec-15 - Dec-22	$ 16,830,657	Transmission Plant	The Round Butte Transmission Upgrades project to replace aging and error prone equipment and install new protective devices to increase system reliability.
P36270	Roseway Substation Expansion	$ 9,219,571	Feb-21	$ 39,470,327	Distribution Plant	The new substation was constructed to serve new load growth in the area, particularly the new South Hillsboro Community ("SoHi"), as well as to improve system flexibility for planned work and unplanned outages. See Exhibit 801 for specific details.
P36587	Upgrade Physical Access Control System	$ 6,334,588	Oct-19 Aug-21	$ 16,601,331	Intangible Plant and General Plant	Replacement of PGE's outdated and unsupported physical access control system (AMAG). The new Physical Access Control System will reduce break fix costs and enable PGE to implement higher security access controls.
P36766	Remote Imaging Project	$ 6,141,962	Jul-20	$ 7,987,851	Intangible Plant	This program is to obtain and operationalize high-fidelity remote sensing information (i.e. LiDAR and hyperspec data and analytics and high-resolution orthoimagery) across PGE's service territory and enable access to this information via PGE's existing GIS platform and a new web-based software solution.
P35959	West Side Hydro Structural/Reliability Upgrade	$ 5,159,304	Dec-15 - Oct-23	$ 15,933,333	Hydro Production	This project provides funding to enhance the capability of four West Side Hydro Powerhouses and other structures to withstand seismic hazards, improve plant reliability over the duration of the new FERC operating license, and address personnel safety issues during routine and extreme events.
P36879	Advanced Distribution Management System Upgrade	$ 4,976,966	Jul-21 Oct-21 Dec-21	$ 29,708,735	Intangible Plant	ADMS is an operational technology system (software platform) that supports the full suite of distribution management, DA, DER optimization, including predicting, monitoring, controlling, optimizing, and safely operating all elements within a distribution system. ADMS functions being developed by utilities include fault location, isolation and restoration; volt/volt-ampere reactive optimization; conservation voltage reduction; flexible load integration; and support for microgrids and transportation electrification. See Exhibit 800 for details.
P36134	Hydro Control System Upgrade	$ 4,546,929	Dec-18 - Dec-23	$ 7,637,665	Hydro Production	This project will upgrade the control systems for generation and fish handling facilities at Pelton Round Butte and West Side Hydros. The new systems will be integrated into the plant information system for archiving and data mining of off-normal operating conditions.
P36522	Distribution Automation Project	$ 4,257,055	Mar-19 - Dec-21	$ 22,111,663	Distribution Plant	PGE is implementing distribution automation schemes at various locations, with the goal of improving system reliability and reducing system risk. See Exhibit 800.
P36391	Willbridge Substation Conversion	$ 3,516,700	Dec-20 Aug-21	$ 10,613,244	Distribution Plant	The project rebuilds the Willbridge Substation to address assets past their end of life and to eliminate the non-standard 11kV distribution voltage. See Exhibit 801 for specific details.
P36680	Brookwood Substation Conversion	$ 3,513,662	Dec-21 Apr-22 Jun-22 Jul-22 Aug-22	$ 23,649,922	Distribution Plant	Brookwood Substation was converted to 115kV to provide capacity for existing and future load growth at Brookwood substation. See Exhibit 801 for specific details.
P36341	St. Mary's West Substation System Protection Upgrade	$ 3,202,244	Apr-22	$ 6,396,181	Transmission Plant	The project is upgrading system protection at St. Mary's West Substation to prevent several large customers from experiencing sustained load loss during summer peak conditions.
P22771	Pelton Round Butte Mitigation Enhancement Fund	$ 3,067,630	Multiple	$ 3,067,630	Intangible Plant	This project is a requirement of the FERC license for the Pelton Round Butte Project. Completion of the project is necessary for compliance with the terms and conditions of the license relating to mitigation funding. This fund will be used to support resource protection measures for project-related impacts not otherwise covered by specific license conditions, including projects that enhance and improve wetland, riparian, and riverine habitats, and riparian aquatic and terrestrial species connectivity that may be affected by the continued operation of the project.
P36667	Residential Flexible Pricing Implementation	$ 2,861,347	Jun-20	$ 2,966,663	Intangible Plant	Software project to implement the Residential Time-of-Use (TOU) rate plan and Peak-Time Rebate (PTR) incentive program designed to encourage residential customers to shift energy usage during peak demand periods, reduce stress on the energy grid, and mitigate the need to build additional fuel-based power plants.
P18834	River District Infrastructure - Install Vaults and Conduits	$ 2,685,962	Dec-21	$ 5,162,638	Distribution Plant	Construction of underground conduits and feeders to serve customers in the River District of NW Portland.
P36742	River Mill Unit 3 Rewind	$ 2,605,427	Feb-20	$ 3,820,440	Hydro Production	This project completed a stator and rotor rewind of River Mill Unit 3. Rewinding the stator and rotor poles will provide PGE's Westside Hydro project with a highly reliable generator capable of operating for 40 to 50 years with proper maintenance practices.
P36706	Human Resources System Implementation	$ 2,256,015	Apr-20	$ 11,275,371	Intangible Plant	Software implementation to move from existing Human Resources systems to an integrated solution (Workday) which promotes consolidation of people, systems, data; process automation and standardization.
P36723	Field Area Network Project	$ 2,154,362	Jul-19 Jan-25	$ 17,824,118	General Plant	A Field Area Network (FAN) implements a wireless communications data network that connects field sensors and control devices to an Integrated Operating Center. See Exhibit 801 for specific details.
P36378	Centennial Substation Upgrades	$ 2,123,268	Jun-19 Feb-25 Jun-25 Aug-25	$ 8,454,349	Distribution Plant	The Centennial Substation was upgraded to modernize the distribution system and to reduce failure risk.
P36617	South Milliken Distribution Line Rebuild	$ 2,057,044	Dec-24	$ 3,928,902	Transmission Plant	The project is replacing the 100 year old 57kV Milliken transmission towers between Faraday and Boring Substations as well as between Boring Substation and Hogan Road in East Multnomah County to eliminate reliability concerns.
P36564	Stephens Substation Conversion	$ 1,935,298	Jul-23 Aug-23 Feb-24	$ 2,933,366	Distribution Plant	The Stephens Conversion project will convert the three existing Stephens' 11kV circuits located in Southeast Portland area to 13kV level and add additional capacity at Harrison Substation with new 3 feeder position switchgear to reduce power outages during a peak period.
P23631	Clackamas Protection Mitigation Enhancement	$ 1,854,468	Multiple	$ 1,993,159	Intangible Plant	This project is a requirement of the FERC license for the West Side Hydro projects for various environmental related projects that enhance and improve wetland, riparian and riverine habitats.
P36683	Distributed Control Software Upgrade	$ 1,753,010	Nov-20 Dec-21 Dec-22 Dec-23	$ 3,316,449	Other Production	This project is upgrading the devices of the existing distributed control software (DCS) to Windows 10 (or later) to ensure continued support by Microsoft.
P36716	Arleta-Holgate Conversion	$ 1,639,408	Dec-23 Dec-25	$ 3,396,180	Transmission Plant	Rebuild the Arleta - Holgate 57kV line to 115kV and convert both Holgate and Arleta Subs from 57kV to 115kV to add capacity for future load growth and improve ability to implement Distribution Automation.
P36510	Carty Water Treatment System Upgrade	$ 1,475,949	Dec-20	$ 4,842,778	Other Production	This project completed the build-out and commissioning of the water treatment systems at Carty for service water and demineralized water to eliminate the need for on-going rental of temporary trailer systems.
P36439	Gresham Substation Rebuild	$ 1,378,689	Dec-20 Sep-22	$ 5,122,009	Transmission Plant	The project is replacing aging infrastructure and rebuilding the 115kV portion of the substation to new seismic standards.
P36679	Orenco Substation Rebuild	$ 1,113,056	Jun-20 Jun-23 Jul-23 Aug-23	$ 5,084,894	Transmission and Distribution Plant	Rebuild the Orenco substation 115kV and reconductor the Orenco-Sunset 115kV line to reduce seasonal outage risk and accommodate future load growth in the Hillsboro area.
P36417	Replace or Rewind Failed Transformers	$ 1,079,671	May-19 - Dec-23	$ 6,719,217	Distribution Plant	This project establishes a fund to replace or rewind failed substation transformers, so that PGE will be more resilient to a wider variety of disaster scenarios.
P36462	Electric Vehicle Charging Station Network Expansion	$ 1,047,330	Aug-20	$ 2,762,766	General Plant	PGE intends to build six electric vehicle charging sites in the service area. This project will support PGE's requirement to accelerate transportation electrification via SB 1547 and will support PGE's core business strategy: business growth and corporate responsibility. The project will also increase the visibility of electricity as a transportation fuel and empower the many customers who need to see convenient public charging infrastructure in order to consider an EV.
P36818	Verint Voice Recording Tool Replacement	$ 1,003,443	Jun-20	$ 1,079,965	Intangible Plant	This project replaced the NICE voice recording hardware with Verint. This software is a compliance tool required by FERC to record traders' conversations and is used by Contact Center for quality assurance.

OPUC DR 142

FERC Form 1 Page 216 - CWIP Balances over $1M at Year End 2018

Form 1 Page 216			[a]	[b]	[c]	[d]/[e]
FP#	**Project Description**	**CWIP Balance**	**In-Service Date(s) Month/Year**	**Project Cost**	**FERC Account Category**	**Narrative Description and Reference to Testimony**
P36337	Mist Natural Gas Storage	$ 133,028,835	May-19	$ 151,573,971	Other Production	Lease at Mist gas facility, which is owned and operated by NW Natural and may be utilized to provide fuel to Port Westward Unit 1, Port Westward Unit 2 and Beaver natural gas generating plants. Per Lease accounting standards in place during 2018, PGE recorded CWIP related to the construction. Lease costs are not included in rate base.
P35679	Marquam Substation Construction	$ 27,245,150	May-19	$ 35,374,352	Distribution Plant and Transmission Plant	The project constructed a new Marquam substation to serve the downtown Portland network load. See Exhibit 801 for specific details.
P36101	Substation Communication Upgrade	$ 16,730,443	Nov-20 Dec-20 Jul-21 Dec-22	$ 38,336,248	General Plant	This project will replace the communications at all PGE substations with new equipment. This project is in response to telephone companies phasing out the equipment currently in use in 2020, putting at risk the ability to communicate with substations if the current equipment breaks and replacement parts are no longer available.
P36039	Harborton Reliability Project	$ 16,003,427	Mar-17 - Sep-21	$ 57,148,565	Transmission Plant	Phase 1 of the Harborton Reliability Project rebuilt the 115kV yard to enhance system reliability. See Exhibit 801 for specific details.
P36422	Transmission System Property Land Purchase	$ 12,626,161	May-24	$ 15,118,052	Transmission Plant	Purchase of land for the new Evergreen substation to increase transmission and distribution system capacity.
P36229	McGill Substation Capacity Additions	$ 11,727,837	May-19	$ 17,216,946	Distribution Plant and Transmission Plant	The McGill Substation was expanded to serve load growth in the area. See Exhibit 801 for specific details.
P35802	Horizon Substation Phase II Project	$ 11,100,546	Mar-19	$ 13,258,151	Transmission Plant	The project installed a second bulk power transformer at Horizon substation to accommodate load growth in the Hillsboro area and maintain compliance with the NERC TPL standards.
P22449	Colstrip Coal Capital Project	$ 9,675,889	Multiple	$ 40,509,627	Steam Production	This project is for work related to the Colstrip power plant and based on the business plan agreed to by Colstrip's owners of which PGE has 20% ownership.
P35572	New Rock Creek Substation Construction	$ 9,043,809	Dec-20	$ 23,382,993	Distribution Plant and Transmission Plant	The new Rock Creek Substation was constructed to alleviate heavy loading on the Bethany Substation and serve new load growth in the North Bethany area. See Exhibit 801 for specific details.
P36167	Repower Faraday Units 1-5	$ 8,980,491	Mar-22	$ 119,384,638	Hydro Production	The Faraday Repower Project will replace PGE's original Faraday Hydro Plant (units 1 through 5) on the Clackamas River. The new powerhouse will consist of two higher efficiency turbines (Faraday Units 7 and 8) housed in a reinforced concrete structure with new flood protection systems and will result in increased plant reliability and efficiency. See Exhibit 700 for specific details.
P35834	Round Butte Transmission Upgrades	$ 7,254,173	Dec-15 - Dec-22	$ 16,830,657	Transmission Plant	The Round Butte Transmission Upgrades project to replace aging and error prone equipment and install new protective devices to increase system reliability.
P36209	Silverton Capacity Addition	$ 6,225,231	May-19 Jun-19 Oct-19 Sep-23	$ 10,905,981	Distribution Plant	The Silverton Capacity Addition Project rebuilt the Silverton Substation to a 57kV breaker station, replacing all antiquated infrastructure within the substation. See Exhibit 801 for specific details.
P36373	Blue Lake Substation Upgrade	$ 6,001,432	Feb-20 Jun-20 Nov-20 Dec-20 Aug-23	$ 37,600,174	Transmission Plant	Installation of new bulk power transformers and switchgear. See Exhibit 801 for specific details.
P36061	Beaver Generator Rewind Program	$ 3,525,718	Feb-19	$ 3,703,319	Other Production	All six generators at Beaver are in need of a rewind. Collecting data from this rewind will provide better insight to the scope and schedule that will be required for future rewinds. Recent partial discharge tests indicate the generator stator winding insulation is degraded which indicates an unacceptable reduction in the reliability of the generators.
P36224	Identity Management and Access Control Software System Upgrade	$ 3,201,847	Apr-19	$ 3,681,943	Intangible Plant	Replaced the IBM Tivoli Identity Management (ITIM) application to meet enhanced audit requirements for access authorization and role-based access control.
P36640	Port Westward Turbine Upgrade	$ 3,166,487	May-19	$ 4,321,317	Other Production	Upgraded the Port Westward Mitsubishi M501G1 turbine to M501G1+ to align with the technology in place at Carty and reduce ongoing LTSA hourly charges.
P36324	Garden Home Substation Upgrade	$ 2,927,614	Aug-19	$ 8,014,511	Distribution Plant	The project replaced the communications technology infrastructure and aged equipment at Garden Home Substation to increase the reliability of service.
P36400	Enablon Software Upgrade	$ 2,680,100	Mar-19	$ 3,307,046	Intangible Plant	This project is to upgrade the Enablon reporting system allowing PGE to eliminate customizations, utilize standard functionality and enhance the interface to be more user-friendly.
P35959	West Side Hydro Structural/Reliability Upgrade	$ 2,647,544	Dec-15 - Oct-23	$ 15,933,333	Hydro Production	This project provides funding to enhance the capability of four West Side Hydro Powerhouses and other structures to withstand seismic hazards, improve plant reliability over the duration of the new FERC operating license, and address personnel safety issues during routine and extreme events.
P36175	Customer Underground Primary Service	$ 2,488,701	Jan-19	$ 2,566,134	Distribution Plant	Construction of a new primary underground commercial service for Nike's Campus expansion in Beaverton, OR.
P36583	Strategic Spare Substation Equipment Purchase	$ 2,281,776	Mar-19	$ 3,937,989	Distribution Plant	Purchase of strategic spare substation equipment to support engineering design schedules and in emergency situations across PGE's service territory as system spares.
P36711	Purchase GIS Software Enterprise Licenses	$ 2,150,000	Mar-19	$ 2,152,628	Intangible Plant	Purchase of perpetual software licenses with new functionality for ARC Geospatial Information System (GIS).
P36501	Build Integrated Operations Center	$ 2,124,474	Mar-19 Jan-20 Nov-21	$ 215,204,041	General Plant	Construction of the new Integrated Operations Center (IOC). See Exhibit 800 for specific details.
P36322	King City - Substation Upgrades	$ 2,082,268	Nov-19	$ 9,242,055	Distribution Plant	The MV90 station at King City lost connection due to the retirement of a Verizon Wireless network. This project replaced the communications technology infrastructure at King City Substation from MV90 station to a SCADA station.
P18834	River District Infrastructure - Install Vaults and Conduits	$ 1,848,625	Dec-21	$ 5,162,638	Distribution Plant	Construction of underground conduits and feeders to serve customers in the River District of NW Portland.
P36407	Development Operations Automation	$ 1,841,420	Dec-19	$ 3,550,666	Intangible Plant	This software project created automated solutions within various software products to improve the efficiency and effectiveness of IT operations and improve ability of IT's internal clients to deliver customer satisfaction.
P36056	Upgrade and Add Revenue Quality Meters	$ 1,840,224	Sep-19	$ 2,282,764	Transmission Plant	Upgrade and add revenue meters at various generation sites and substations to have better visibility into transmission system and generation sites.
P36496	As-Built Drawings	$ 1,768,951	Dec-22	$ 1,768,951	Distribution Plant	Contact with external party to perform as-built services for the Geospatial Information System (GIS) that can update construction activity information to GIS team in a timely manner.
P36527	Tapline Reliability Improvement Program (TRIP) Implementation	$ 1,685,118	Dec-22	$ 2,521,888	Distribution Plant	Upgrade of the protective devices on qualified tap lines from a fuse to a electronic programmable reclosing cutout to improve reliability for customers and decrease the non-asset risk for PGE.
P36134	Hydro Control System Upgrade	$ 1,368,835	Dec-18 - Dec-23	$ 7,637,665	Hydro Production	This project will upgrade the control systems for generation and fish handling facilities at Pelton Round Butte and West Side Hydros. The new systems will be integrated into the plant information system for archiving and data mining of off-normal operating conditions.
P35914	Substation Fitness Project - Replace, Repair and Upgrade Aging Substation Equipment	$ 1,362,770	Mar-20	$ 4,062,598	Distribution Plant	The substation FITNES program replaced and upgraded obsolete and failed substation equipment to avoid substation equipment failures leading to customer outages.
P36334	Sherwood Security Upgrades	$ 1,297,772	Jun-19	$ 4,229,399	Transmission Plant	This project strengthened the physical security measures utilized at the Sherwood Substation to effectively deter, detect, delay, assess, communicate, and respond to a physical attack.
P36089	Transmission Pole Inspection and Replacement	$ 1,271,621	Dec-21	$ 7,645,747	Transmission Plant	The project inspected and replaced failed transmission poles to improve PGE infrastructure and reduce the likelihood of an incident.
P36541	T&D/Generation Key Metric Software Development	$ 1,218,847	Apr-19	$ 1,474,803	Intangible Plant	Creation of a software solution to create an operational data store to provide a foundational data source for Transmission, Distribution and Generation (TD&G) metrics to better measure and monitor performance.
P36100	Bethel to Round Butte Fiber Optic Communication Project	$ 1,106,884	Dec-24	$ 1,144,934	General Plant	The project installed All-Dielectric Self Supporting (ADSS) fiber optics between Bethel to Round Butte to provide high speed data with high reliability to all major PGE resources spread throughout the State of Oregon.
P36042	Tektronix Substation Upgrade	$ 1,090,454	Dec-19	$ 2,095,520	Distribution Plant	This project added a distribution transformer, switchgear, and new distribution feeders to Tektronix substation to support a large customer's expansion project.
P36270	Roseway Substation Expansion	$ 1,075,989	Feb-21	$ 39,470,327	Distribution Plant and Transmission Plant	The new substation was constructed to serve new load growth in the area, particularly the new South Hillsboro Community ("SoHi"), as well as to improve system flexibility for planned work and unplanned outages. See Exhibit 801 for specific details.
P36503	Enterprise Performance Monitoring	$ 1,025,917	Mar-19	$ 1,145,577	Intangible Plant	Software solution to implement Enterprise Performance Monitoring to enable the ability to take preemptive actions to head off both impacting IT events through event monitoring with limited self healing and to monitor capacity related problems.

July 23, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 143
Dated June 24, 2021

Request:

Regarding 2021 plant additions not separately listed in CWIP at December 31, 2020,

a. Please provide a list of individual projects with an expected cost of $500,000 or greater.
b. Please provide the date each project is expected to be placed into service.
c. Please provide the FERC account category for each project (Intangible, Steam, Hydraulic, Other Production Plant, Transmission, Distribution, or General).
d. Please provide a brief narrative description of the nature of the project including why it is necessary and how ratepayers will benefit.
e. Please cross reference to the line item project number in the 2021 new construction budget (Supplemental Application in Docket No. RE 18, filed 3/31/21), if applicable. Alternatively, if the project is included in the "Non-Major" line of the RE 18 report, please indicate.

Response:

Attachment 143-A provides the requested information.

OPUC DR 143

2021 + Jan-Apr 2022 Plant Additions Not Listed Separately in CWIP at 12/31/2020

Funding Project Number	Funding Project Description	Functional Class	Estimated In-Service Month/Year	Project Description	RE-18 Reference	Forecast Additions 2021 - Apr 2022
P17443	T&D Major System Inspect, Replace	Distribution	Monthly	Ongoing project to inspect and correct routine deficiencies of poles and overhead facilities to comply with the National Electric Safety Code (NESC). This program is part of the Facility Inspection and Treatment to National Electric Safety Code (FITNES) to improve system reliability and reduce outages.	Distribution	$ 51,052,891
P36959	2022 Distribution Blanket Projects	Distribution	Monthly	Ongoing projects to replace failed underground cables to reduce outage response and temporary repair costs; inspect and correct routine deficiencies of overhead and underground devices to comply with the NESC; distribution work for overhead and underground line construction including pole replacements, reconductors, road widenings/relocations, joint pole construction and replacement of damaged facilities by third parties; construction of distribution lines for new customers and upgrade of service to existing customers.	n/a	$ 48,569,504
P37048	Outage or Emergency Replacement	T & D	Various	Unplanned asset replacements associated with outages and/or emergent safety issues. Equipment typically replaced by this program includes distribution transformers, pole replacements, switch replacements, reclosers, etc. Includes the February 2021 storm costs.	P37048 - Minor	$ 37,839,010
P14628	Replace Failed Underground Cables	Distribution	Monthly	Ongoing project to replace failed underground cables to reduce outage response and temporary repair costs.	Distribution	$ 15,792,924
P36394	Vintage Vehicle Replacement II	General	Monthly	Ongoing program to purchase vehicles and equipment to replace existing assets having maintenance or reliability concerns.	P36394 - Major	$ 13,775,376
P36522	Distribution Automation	Distribution	Monthly	Implementation of distribution automation schemes at various locations with the goal of improving system reliability and reducing system risk.	Distribution	$ 12,828,737
P36770	Street and Area Light Construction	Distribution	Monthly	Ongoing project for construction and design of new installations, removals and upgrades of lighting for municipalities, property developers, residential and commercial customers.	Distribution	$ 10,427,824
P36836	BR: Beaver Modernization	Other Production	Apr-22	Modernization efforts at the Beaver plant to upgrade the gas turbine combustion systems from a dual fuel system to a single fuel dry low NOx system to reduce overall emissions. The single fuel will be natural gas and the upgraded units will be prevented from operating on fuel oil as an alternative. The combustion upgrade will allow for greater operationally flexibility while meeting PGE's commitment to reduced greenhouse gas emissions at the site.	n/a	$ 10,172,085
P36868	Shute Capacity Addition	T & D	Dec-21	The capacity at Shute substation must be increased to maintain full N-1 redundancy for all customers due to new load growth served from the substation. See Exhibit 801 for more details.	Distribution	$ 10,006,219
P37111	Supply Chain Evolution	Intangible	Sep-21	Improve performance, increase efficiency and reduce costs of PGE's end-to-end supply chain by implementing an intuitive, best-of-breed, cloud-based technical platform that enables enhanced Source-to-Pay, Inventory Management and Accounts Payable capabilities.	n/a	$ 9,653,986
P36723	Field Area Network Project (FAN)	General	Monthly	The Field Area Network (FAN) is a new wireless communications network that connects field sensors and control devices throughout the electrical distribution system to the Integrated Operations Center. See Exhibit 800 more specific details.	P36723 - Major	$ 8,886,285
P35890	Purchase Distribution Transformers	Distribution	Monthly	Ongoing project to purchase overhead and underground transformers for new construction and system replacements to ensure system reliability.	Distribution	$ 8,533,049
P36907	Reconductor Murrayhill-St Mary's	Transmission	Apr-22; Jun-22	Reconductor the existing Murrayhill-St Mary's 230kV transmission line to increase the reliability of PGE's transmission system through improvement of the summer rating of the line by over 300 MW.	Transmission Non-Major	$ 7,927,599
P36116	Wind Generation Fitness Program	Other Production	Various	Project to replace failed major equipment such as gearboxes, main bearings, generators, inverters of PGE's Wind Generation facilities to maintain plant output and availability.	P36116 - Major	$ 7,677,774
P37118	WSH:Restore Facilities post-fire	Hydro	Dec-21	Restoration of West Side Hydro Project facilities from the damage sustained by the Riverside Fire.	n/a	$ 6,923,382
P37017	Facilities Upgrades-EV Readiness	General	Sep-21,Dec-21,Aug-22,Dec-22	This project will install EV infrastructure at all PGE Facilities needed to enable PGE Fleet electrification.	n/a	$ 6,909,917
P36913	Trans. Line Clearance Mitigation	Transmission	Various	This project will design and install replacement for transmission poles that have identified clearance violations. PGE has published standards for clearance transmission pole clearance requirements at maximum operating temperatures. An inspection identified poles that are in violation of these standards that require correction.	P36913 - Major	$ 6,868,560
P37046	T&D Asset Relocation	T & D	Various	Relocation of Transmission and Distribution and facilities, mainly driven by public works including state and local projects.	P37046 - Minor	$ 5,949,303
P35172	PSES - Generation Fitness Fund	Other Production	Various	Ongoing project to for known, emerging and routine capital jobs that are essential for maintaining the fitness of PGE generation facilities. Funds known and emerging routine capital projects that are small in nature but essential for maintaining PGE Generation plants.	P35172 - Major	$ 5,725,657
P36762	Milliken Tower Reinforcement	Transmission	Sep-21	Reinforcement of transmission towers, due to excessive corrosion along 14 miles of the Springwater Corridor.	n/a	$ 5,625,890
P36861	Division Transit Project (DTP)	T & D	Monthly	PGE will partner to support TriMet & PBOT in updating one of its bus lines from Division Street SE 12th to Main Street in Gresham. At the same time PBOT will be updating intersections in the three major locations and PGE will be replacing poles along this route to accommodate the new PBOT fiber line in the comm space by putting in taller poles and working with the comms to adjust for clearance.	Distribution	$ 5,535,825
P37109	Customer Data Centers	Distribution	Various	Capital costs associated with the construction of 3 data centers. Distribution switches and cable will be split between 3 customers: Flexential (due Apr 2021), Stack (due Apr 2021) and T5 (due Feb 2021).	n/a	$ 5,448,729
P36911	Wildfire Mitigation	T & D	Various	Program consisting of activities to mitigate risk of wildfire ignitions as well as utilize a systematic risk evaluation approach to identify highest value work to further reduce wildfire risk. See Exhibit 800 for specific details.	Distribution	$ 5,318,410
P37061	OH FITNES Transmission	Transmission	Monthly	Transmission pole replacements of 115kV and above that are identified through the OH FITNES Inspections.	P37061 - Minor	$ 5,149,925
P37110	Restore Bethel-RB 230 kV Line	Transmission	Nov-21	Restoration of the Bethel-Round Butte 230 kV Transmission line from 2020 fire damage.	n/a	$ 4,519,473
P36537	Unjacketed Cable Replacement Prgrm	Distribution	Monthly	Program to replace unjacketed, direct buried cables in PGE's service territory which have a high likelihood of neutral corrosion. Improves system reliability.	Distribution	$ 4,210,334
P35892	Purchase Customer Meters	Distribution	Monthly	Ongoing project to purchase customer meters for new customer connects, system replacements and spare meter inventory.	Distribution	$ 3,966,655
P37047	Joint Pole Construction	Distribution	Various	Capital work associated with Joint Pole Construction for non-discriminatory access of 3rd party attachments on PGE poles and non-PGE owned poles.	P37047 - Minor	$ 3,665,888
P36867	Remote Disconnect Project	Distribution	Monthly	Exchange meters to install remote disconnect meters which will enable connections and disconnections over the air. This technology drives O&M efficiencies and leverages most current technologies.	Distribution	$ 3,659,899
P35085	Substation Fitness	T & D	Various	Ongoing project to add, install, remove and replace obsolete and failed substation equipment to improve overall reliability.	n/a	$ 3,511,795
P35938	Field Voice Communications System	General	Monthly	Replacement of PGE's current mobile radio communication system. Majority of work completed prior to 2020 and remaining work relates primarily to Pelton/Round Butte.	n/a	$ 3,320,120
P36545	Tree Wire Installment Program	T & D	Monthly	Replacement of bare overhead conductor with tree wire to reduce vegetation related non-asset failure risk on the distribution system.	Distribution	$ 3,289,660
P37143	Credit Remote Connect Meters	Distribution	Monthly	Exchange non-remote meters at the time of customer disconnection with remote meters to allow for the customer to be reconnected automatically once service is restored.	n/a	$ 3,144,821
P36910	Outer Div Multi-Modal Safety Proj	Distribution	Jun-21	PGE will support City of Portland safety improvement project by moving approximately 100 poles for ADA access ramps, signalize pedestrian crossings, protected bike lanes, improved traffic controls, and modification of turn lanes.	Distribution	$ 2,843,524
P37133	2021 Network Fitness	General	Monthly	Ongoing project to purchase hardware and software required to run, grow support, improve and maintain the PGE corporate network that spans all of PGE locations and supports communication organization wide.	n/a	$ 2,787,758
P36089	Transm Full Pole Inspct & Replace	Transmission	Monthly	Inspection and replacement of failed transmission poles to maintain system reliability.	Transmission Non-Major	$ 2,615,837
P36543	PRC-002 Protection Upgrades	Transmission	Various	Upgrades of protection equipment at various substations that are not compliant with the PRC-002 standard. PGE must comply by 7/1/2022 to avoid punitive fines.	Transmission Non-Major	$ 2,581,523
P35228	Clackamas PME Road Fund	Hydro	Jul-21; Dec-21	This project is a requirement of the FERC license for the Clackamas license. The requirement is to improve various roads in the vicinity of PGE facilities located in the Mt Hood National Forest.	P35228 - Minor	$ 2,541,207
P37135	2021 Server Storage Fitness	General	Monthly	Ongoing project that includes all hardware, software and labor required to replace or update end of life systems within the corporate infrastructure as well as to accommodate for standard system growth.	n/a	$ 2,341,451
P37131	2021 Desktop Fitness	General	Monthly	Ongoing project to support routine purchases of desktop equipment (computers, laptops, etc.) for PGE employees.	n/a	$ 2,128,598
P37085	2021 Infrastructure Fitness Blanket	General	Monthly	This project is for emerging infrastructure replacement of aging servers, storage, networks, desktops, and cybersecurity infrastructure. Funding will be allocated from this blanket to three sub-blankets: Desktop Fitness/Upgrade, Network, and Server Storage. Individual projects will then be funded by the sub-blankets.	P37085 - Major	$ 2,122,332
P35484	Repl Trans Structures & Insulators	Transmission	Monthly	Replacement of transmission insulators for regulatory compliance and to maintain reliability of the system.	Transmission Non-Major	$ 1,931,991
P37157	Mobile 3.0	Intangible	Dec-21	Ongoing transformation of the Mobile platform to 1) Empower Customers on their energy journey through adding start stop move, Ways to save and autopay support, incrementing accessibility and voice over capability improvements for the visually impaired 2) Increase load flexibility through PSPS support, flex partner and power partner Mobile 3) Increase adoption through digital payments, Brand reboot, voice assistant integration and Spanish Language Support 4)Increase platform resiliency by enabling graph Q, improving Dev ops and automation and add deeper analytics for data driven production decisions.	n/a	$ 1,885,269
P37114	Project BaT	Distribution	Monthly	Project BaT is a customer driven project for land being developed by a Large Key Customer. They require a 9000 amp service at 480V from PGE to service the site. The site is southwest of PGE's Shute substation, but cannot be served from this substation due to it only having a 34.5kV distribution system. The customer and PGE will share the pathway costs according to PGE tariffs and it will be split according to the estimate.	n/a	$ 1,651,187
P36921	PGE/DTNA HD charging Demonstration	Distribution	Apr-21	PGE will partner with Daimler Trucks North America (DTNA) to design and build a heavy-duty electric vehicle charging demonstration site on Swan Island.	n/a	$ 1,605,660
P36105	Dispatchable Standby Generation (DSG)	Other Production	Jun-21,Dec-21	Construction of Dispatchable Standby Generation (DSG) projects at various customer sites to increase non-spinning capacity to serve customers in periods of high demand.	Production Non-Major	$ 1,573,344
P37049	Line Crew Truck Stock Materials	Distribution	Monthly	Ongoing project designated for the replacement of equipment and material used for general construction and repair, such as splices, cutouts, arresters, jumpers etc. These devices and materials are used to manage, operate and repair the electric distribution and transmission systems.	P37049 - Minor	$ 1,503,277
P37095	SCADA Replacement - Grizzly Substation	Transmission	Dec-21	PGE's share of SCADA replacement at the Grizzly Substation (owned by BPA).	P37095 - Minor	$ 1,372,075
P36727	Energy Storage, Microgrid	Distribution	Dec-21	Construct customer-sited energy storage microgrid installations, including deployments at Beaverton Public Safety Center (completed in prior years), City of Portland EOC, and Anderson Readiness Center.	Distribution	$ 1,286,205
P37103	ODOT OR213/SE82nd Foster to Lindy	Distribution	Monthly	In support of ODOT activities, pole replacements on OR213 SE Foster to Lindy encompasses 2 miles and approximately 100 poles from SE Foster to SE Thompson.	Distribution	$ 1,225,955
P35591	As-Built Drawings - Generation	Generation	Monthly	Ongoing project to provide as-built drawings for recently constructed projects to provide reliable and accurate drawings of generation facilities.	Production Non-Major	$ 1,168,583
P36742	RM: Rewind Units 3, 2, 1	Hydro	2025	This project completed a stator and rotor rewind of River Mill Unit 3, due to degradation in the stator and rotor poles which went in service in 2020. The remaining scope of this Funding Project is being increased to perform complete stator and rotor rewinds for Units 1 and 2.	n/a	$ 1,159,740
P36464	Facilities Asphalt R&R Project	General	Various	Ongoing program to install or remove asphalt at various different PGE sites to maintain safety at the facilities.	General Non-Major	$ 1,135,500
P37175	Electronic Payment Redesign Phase 2	Intangible	Nov-21	Redesign of electronic payments to enable new functionality included automating reconnect when customer pays their notice amount, automate alerts for declined or failed scheduled payments and enable PayPal and Amazon Pay via web, mobile and CSR.	n/a	$ 1,113,611
P37113	Web Next Gen 2.0 Phase II	Intangible	Mar-21	Finalize PGE website migration from old site to the new site to provide a more user-friendly experience for customers.	n/a	$ 1,081,581
P36602	RB: Replace Hatchery Chiller System	Hydro	Aug-21	Replacement of the aging Round Butte Hatchery Chiller system to increase capacity and reduce the ongoing maintenance costs and reduce the risk of failure.	Production Non-Major	$ 920,314
P37155	Time of Day	Intangible	Sep-21	The Time of Day project will implement a new Time of Use rate and the functionality required to support customer enrollment, billing, and participation.	n/a	$ 888,088
P37094	Replace SCADA RTU with SER	Transmission	Dec-21	PGE's share to replace the SCADA RTU at Malin Substation (owned by BPA) with current SCADA/SER.	P37094 - Minor	$ 850,950
P35995	Downtown UG Core Cable Replacement	Distribution	Monthly	Replacement of underground cable and splices in the downtown Portland core network to mitigate the risk of extended failure and outages.	Distribution	$ 818,262
P16567	UG FITNES	Distribution	Monthly	Ongoing project to inspect and correct routine deficiencies of underground devices to comply with the National Electric Safety Code (NESC). This program is part of the Facility Inspection and Treatment to National Electric Safety Code (FITNES) to improve system reliability and reduce outages.	Distribution	$ 808,931
P35959	WSH Structural/Reliability Upgrades	Hydro	Oct-21	This project provides funding to enhance the capability of four West Side Hydro Powerhouses and other structures to withstand seismic hazards, improve plant reliability over the duration of the new FERC operating license, and address personnel safety issues during routine and extreme events.	P35959 - Major	$ 746,265
P37108	Proactive Outage (Software)	Intangible	Feb-21	Software project to implement improvements to customer communications on outages.	n/a	$ 735,709
P36285	Purchase T&D - Tools & Lab Equipment	General	Monthly	Ongoing program to purchase tools, equipment and portable electrical instruments that are required to perform normal construction and repair work.	Distribution	$ 732,810
P37106	Mobile 2.0	Intangible	Mar-21	Enhancement of PGE's Mobile App to optimize the website for an improved customer experience.	n/a	$ 720,301
P36855	Wheatridge Renewable Energy Facility	Other Production	Dec-20	Project consists of a 300MW wind facility, 50MW solar facility, and a 30MW 4-hr duration energy storage facility, owned by Wheatridge Wind, LLC, a subsidiary of NextEra Energy Resources. 100 MW of the wind resource will be purchased by Portland General Electric(PGE) and the remaining 200 MW will be contracted by PGE for a 30-year term. The solar energy storage facilities will be contracted to PGE under one Power Purchase Agreement (PPA), with a 30-year term for solar and a 20-year term for storage. NextEra will serve as the operator and provide Operations and Maintenance (O&M) for all aspects of the facility with O&M for the 100 MW ownership portion provided under a 30-year agreement. 2021 costs represent trailing charges as the plant was placed in-service in December 2020.	P36855 - Major	$ 702,680
P35846	CPP Switch Replacement	Distribution	Monthly	Ongoing project to replace Canada Power Products (CPP) switches with submersible S&C Vista switches in various locations throughout PGE's service territory to reduce failure risk and improve system reliability.	Distribution	$ 651,429
P35894	Communications Fitness	General	Monthly	Ongoing work to implement communication equipment to maintain the reliability and supportability of PGE's communications infrastructure to support critical business systems and services.	General Non-Major	$ 624,430
P35556	Avian Protection Program	Distribution	Monthly	Ongoing project to install poles and nesting platforms to reduce risks to avian species.	Distribution	$ 610,186
P36235	Install Low OH Services Guarding	Distribution	Monthly	Ongoing project to install guarding to correct low services to residential areas that do not meet minimum height requirements listed in the NESC.	Distribution	$ 585,806
P36641	Oil Spill Containment Modifications	T & D	Various	Ongoing project to implement oil spill containment modifications at various substation to reduce environmental risk.	Distribution	$ 571,522
P35349	Dist Line Sys - Equip Replacement	Distribution	Various	Ongoing project to install and replace overhead switches, reclosers, line regulators to maintain the reliability of the distribution system.	Distribution	$ 542,534
P37121	Durham Substation Separation	Distribution	Jul-21	This project is to purchase the land where PGE's Durham distribution substation is located and to fund the acquisition of certain Clean Water Services substation assets. Future funds will be required to separate PGE's Durham substation facilities from Clean Water Services switchgear facilities at this location.	n/a	$ 539,778
P35565	PSES - Generation Site Paving	Other Production	Various	Ongoing project to construct or resurface roads, parking lots at generation facilities.	n/a	$ 516,868
P23970	Corporate Strategic Fiber Project	General	Dec-21	Installation of fiber optic cable in the Portland metro and Salem areas over multiple years to support strategic corporate communication requirements and improve connectivity to multiple PGE facilities.	n/a	$ 501,531

August 20, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 311
Dated August 6, 2021

Request:

Please see Table 1 on PGE / 800, Bekkedahl – Jenkins / 4.

a. Please provide an itemized list of all items in this table.
b. In your answer, please indicate the following:
   i. Cost
   ii. Voltage where applicable
   iii. In service date by day, month, and year
   iv. Whether these items were recently reclassified, and if not, whether a 7-factor test was applied to each of these items.
   v. Whether these are distribution or transmission items

Response:

Attachment 311-A provides the requested information.

OPUC DR 311 - Table 1 on PGE / 800 / 4
Plant Additions January 2019 through April 2022

		Table 1 Grouping									By Function			
Project	Total Additions	Poles & Wires	Substations	IOC	Line Transformers	Meters	ADMS	Field Voice	FAN	Remote Sensing	Distribution	Transmission	Other Functions	In Service Date (Jan '19 - Apr' 22)
P36501 - Integrated Operations Center (IOC)	215 198 605	-	-	215 198 605	-	-	-	-	-	-	-	-	215 198 605	Nov-21
P17443 - T&D Major System Inspect, Replace	156,453,928	139,799,440	-	-	8,327,244	8,327,244	-	-	-	-	155,849,711	604,216	-	Monthly
P35924 - Distribution System Construction II	149,324,377	134,524,017	1,546,245	-	10,137,924	3,116,191	-	-	-	-	149,262,968	61,409	-	Monthly
P35925 - Dist. Customer Line Construction II	107,247,031	89,082,456	15,386	-	8,558,227	9,590,962	-	-	-	-	107,247,031	-	-	Monthly
P36708 - Butler Substation Construction	70,627,152	1,656,064	68,971,088	-	-	-	-	-	-	-	70,470,473	156,679	-	Nov-20 Dec-20 Apr-21 Mar-22
P36039 - Harborton Reliability Project PH1	56,155,834	3,095,560	53,060,274	-	-	-	-	-	-	-	24,963,737	31,192,097	-	Mar-17 - Sep-21
P14628 - Replace Failed Underground Cables	47,668,661	42,907,892	-	-	4,760,769	-	-	-	-	-	47,668,660	-	-	Monthly
P37048 - Outage or Emergency Replacement	41,690,051	36,317,394	-	-	5,372,657	-	-	-	-	-	41,690,050	-	-	Monthly
P36373 - Blue Lake Phase II	36,940,401	22,675,481	14,264,920	-	-	-	-	-	-	-	22,061,151	14,879,249	-	Feb-20 Jun-20 Nov-20 Dec-20
P35679 - Construct Marquam Project	35,359,727	24,985,457	12,608,108	-	(2,233,838)	-	-	-	-	-	35,359,727	-	-	May-19
P36537 - Unjacketed Cable Replacement Prgrm	33,581,511	33,581,511	-	-	-	-	-	-	-	-	33,581,511	-	-	Monthly
P36879 - Advanced Distribution Mgt System (ADMS)	27,383,567	-	-	-	-	-	27,383,567	-	-	-	-	-	27,383,567	Jul-21 Oct-21 Dec-21
P35890 - Purchase Distribution Transformers	26,523,272	-	-	-	26,523,272	-	-	-	-	-	26,523,272	-	-	Monthly
P36680 - Brookwood Substation Conversion	23,612,587	275,596	23,336,991	-	-	-	-	-	-	-	11,191,418	12,421,170	-	Dec-21 Apr-22
P36693 - Helvetia Substation	22,449,119	-	22,449,119	-	-	-	-	-	-	-	22,449,119	-	-	Aug-21
P36770 - Street and Area Light Construction	21,846,834	21,846,834	-	-	-	-	-	-	-	-	21,846,834	-	-	Monthly
P35572 - Build New Rock Creek Substation	21,474,133	10,299,276	11,174,857	-	-	-	-	-	-	-	21,431,271	42,862	-	Dec-20
P36270 - Roseway Substation Expansion	20,371,438	4,856,813	15,514,625	-	-	-	-	-	-	-	18,338,708	2,032,730	-	Feb-21
P36861 - Division Transit Project (DTP)	20 127 130	20 127 130	-	-	-	-	-	-	-	-	20 708 479	(581 349)	-	Monthly
P36522 - Distribution Automation	20,122,204	18,260,260	1,861,945	-	-	-	-	-	-	-	20,122,203	-	-	Monthly
P35980 - PCB Transformer Replacement	17,826,204	13,014,660	-	-	4,811,545	-	-	-	-	-	17,826,204	-	-	Monthly
P35398 - Field Voice Communications	17,449,015	-	-	-	-	-	-	17,449,015	-	-	-	-	17,449,015	Monthly
P36229 - McGill Sub Capacity Additions	16,876,769	2,741,974	14,134,795	-	-	-	-	-	-	-	16,542,268	334,501	-	May-19
P36723 - Field Area Network (FAN)	16,194,961	-	-	-	-	-	-	-	16,194,961	-	-	-	16,194,961	Monthly
P35892 - Purchase Customer Meters	15,252,247	15,285	-	-	-	15,236,962	-	-	-	-	15,252,247	-	-	Monthly
P35802 - Horizon Phase II Project	13,258,147	13,220,170	37,977	-	-	-	-	-	-	-	278,569	12,979,578	-	Mar-19
P35834 - Round Butte Transmission Upgrades	11,843,034	-	11,843,034	-	-	-	-	-	-	-	-	11,843,034	-	May-20
P36209 - Silverton Capacity Addition	10,905,981	1,644,875	9,261,106	-	-	-	-	-	-	-	10,905,981	-	-	May-19 Jun-19 Oct-19
P36391 - Willbridge Station 11kV Conversion	10,596,085	17,159	10,578,926	-	-	-	-	-	-	-	10,578,926	17,159	-	Dec-20 Aug-21
P36868 - Shute Capacity Addition	10,006,219	-	10,006,219	-	-	-	-	-	-	-	10,006,219	-	-	Dec-21
P36913 - Trans. Line Clearance Mitigation	9,617,492	9,617,492	-	-	-	-	-	-	-	-	8,553,605	1,063,887	-	Monthly
P36571 - Marquam Radial Feeder Addition	9,483,577	9,483,577	-	-	-	-	-	-	-	-	9,483,577	-	-	Apr-21 May-21 Jul-21
P36763 - Install Horizon VWR3 Transformer	9,090,876	102,186	8,988,690	-	-	-	-	-	-	-	730,989	8,359,886	-	May-21 Jun-21 Aug-21
P36417 - Replace/Rewind Failed Transformers	8,902,353	10,055	3,986,197	-	4,906,101	-	-	-	-	-	7,501,543	1,400,809	-	Monthly
P36867 - Remote Disconnect Project	8,497,001	11,761	-	-	-	8,485,240	-	-	-	-	8,497,001	-	-	Monthly
P36324 - Garden Home Substation Upgrade	7,997,233	361,364	7,635,869	-	-	-	-	-	-	-	7,688,995	308,238	-	Aug-19
P36766 - Remote Sensing Project	7 987 851	-	-	-	-	-	-	-	-	7 987 851	-	-	7 987 851	Jul-20
P36907 - Reconductor Murrayhill-St Marys	7,927,599	7,927,599	-	-	-	-	-	-	-	-	-	7,927,599	-	Apr-22
P36089 - Transm Full Pole Inspct & Replace	7,593,585	7,593,585	-	-	-	-	-	-	-	-	2,507	7,591,078	-	Monthly
P37062 - Rebuild Grizzly-RB 500kV Towers	6,874,197	6,874,197	-	-	-	-	-	-	-	-	-	6,874,197	-	Aug-20
P36341 - St Marys Battery Addition	6,396,181	-	6,396,181	-	-	-	-	-	-	-	-	6,396,181	-	Apr-22
P36910 - Outer Div Multi-Modal Safety Proj	6,213,950	6,213,950	-	-	-	-	-	-	-	-	6,213,950	-	-	Jun-21
P37046 - T&D Asset Relocation	5,949,303	5,949,303	-	-	-	-	-	-	-	-	4,605,242	1,344,060	-	Monthly
P36911 - Wildfire Mitigation	5,895,474	5,877,721	17,752	-	-	-	-	-	-	-	3,672,116	2,223,358	-	Monthly
P36545 - Tree Wire Installment Program	5,847,903	5,847,903	-	-	-	-	-	-	-	-	5,847,903	-	-	Monthly
P36470 - Sensus DT34 Meter Exchanges	5,702,996	200	-	-	-	5,702,797	-	-	-	-	5,702,996	-	-	Monthly
P36450 - Urban Feeder UG Conversion	5,654,852	5,654,852	-	-	-	-	-	-	-	-	5,654,852	-	-	Jul-19
P36762 - Milliken Tower Reinforcement_SE PDX	5,625,890	5,625,890	-	-	-	-	-	-	-	-	-	5,625,890	-	Sep-21
P36582 - Substation FITNES 2019-2021	5,587,315	79,106	5,508,209	-	-	-	-	-	-	-	4,363,561	1,223,754	-	Various
P37109 - Customer Data Centers	5,448,729	5,448,729	-	-	-	-	-	-	-	-	5,448,729	-	-	Various
P18834 - Station E: River District Infrastr	5,162,638	5,162,638	-	-	-	-	-	-	-	-	5,162,638	-	-	Monthly
P37061 - OH FITNES Transmission	5,149,925	5,149,925	-	-	-	-	-	-	-	-	185,936	4,963,988	-	Monthly
P36679 - Orenco Substation 115kV Rebuild	5,056,326	5,510,574	(454,248)	-	-	-	-	-	-	-	5,029,714	26,613	-	Jun-20
P36439 - Gresham Sub 115kV Rebuild	4,963,701	-	4,963,701	-	-	-	-	-	-	-	4,303,029	660,672	-	Dec-20
P35908 - SAM: Proactive UG Cable Program	4,627,387	4,627,387	-	-	-	-	-	-	-	-	4,627,387	-	-	Monthly
P37110 - Restore Bethel-RB 230 kV Line	4 519 473	4 519 473	-	-	-	-	-	-	-	-	-	4 519 473	-	Nov-21
P36846 - Intel Water Add and Replace Cables	4,289,261	3,908,809	380,453	-	-	-	-	-	-	-	4,289,261	-	-	Oct-19
P36334 - Sherwood Security Upgrades	4,226,302	-	4,226,302	-	-	-	-	-	-	-	-	4,226,302	-	Jun-19
P35914 - Substation Fitness 2015-2018	3,940,972	(7,234)	3,948,206	-	-	-	-	-	-	-	3,583,112	357,860	-	Various
P36583 - Strategic Spare Substation Equip	3,937,989	-	3,937,989	-	-	-	-	-	-	-	3,937,989	-	-	Various
P35095 - Dist System Line Construction	3,836,046	4,137,772	-	-	(138,023)	(163,703)	-	-	-	-	3,836,046	-	-	Monthly
P16567 - T&D System Major Maintenance-UG	3 720 580	2 757 818	-	-	481 381	481 381	-	-	-	-	3 720 580	-	-	Monthly
P37047 - Joint Pole Construction	3,665,888	3,665,888	-	-	-	-	-	-	-	-	2,626,223	1,039,665	-	Monthly
P36388 - Oswego Substation Rebuild	3,318,626	3,318,626	-	-	-	-	-	-	-	-	3,318,626	-	-	Dec-19
Other - Miscellaneous Projects	3,890,531	10,630,060	(4,155,317)	-	(1,422,114)	(1,162,097)	-	-	-	-	(5,603,191)	9,493,721	-	Various
P36056 - Upgrade/Add Revenue Meters	3,274,038	-	3,274,038	-	-	(0)	-	-	-	-	528,749	2,745,288	-	Monthly
P37143 - Credit Remote Connect Meters	3,144,821	-	-	-	-	3,144,821	-	-	-	-	3,144,821	-	-	Monthly
P35484 - Repl Trans Structures & Insulators	3,033,160	3,033,160	-	-	-	-	-	-	-	-	537,594	2,495,566	-	Monthly
P36543 - PRC-002 Protection Upgrades	2,662,717	-	2,662,717	-	-	-	-	-	-	-	1,712,916	949,801	-	Monthly
P36645 - DPU Relay Replacement Program	2,607,666	310,387	2,297,278	-	-	-	-	-	-	-	2,607,665	-	-	Monthly
P36175 - Nike Campus UG Primary Service	2,566,134	2,566,134	-	-	-	-	-	-	-	-	2,566,134	-	-	Jan-19
P36527 - TRIP (TripSaver II) Implementation	2,521,888	2,521,888	-	-	-	-	-	-	-	-	2,521,888	-	-	Monthly
P24723 - Substation Arc Flash Mitigation	2,477,844	2,109,342	2,477,844	-	(2,109,342)	-	-	-	-	-	2,477,844	-	-	Various
P36937 - North Lombard ODOT Project	2,309,999	2,309,999	-	-	-	-	-	-	-	-	2,309,999	-	-	Dec-20
P36042 - Tektronix Substation Upgrade	2,095,520	2,058,576	36,945	-	-	-	-	-	-	-	2,086,426	9,095	-	Oct-19
P36550 - QF Interconnection Costs	1,856,412	25,062	1,831,350	-	-	-	-	-	-	-	1,479,791	376,668	-	Various
P35846 - CPP Switch Replacement	1,824,381	1,824,381	-	-	-	-	-	-	-	-	1,824,381	-	-	Various
P36454 - Substation Rerock - multiple sites	1,805,693	-	1,805,693	-	-	-	-	-	-	-	1,722,485	83,208	-	Various
P36235 - Install Low OH Services Guarding	1,726,431	1,726,431	-	-	-	-	-	-	-	-	1,726,431	-	-	Monthly
P37103 - ODOT OR213/SE82nd Foster to Lindy	1,670,956	1,670,956	-	-	-	-	-	-	-	-	1,670,956	-	-	Monthly
P37114 - Project BaT	1 651 187	1 651 187	-	-	-	-	-	-	-	-	1 651 187	-	-	Oct-21
P36921 - PGE/DTNA HD charging Demonstration	1,605,660	1,605,660	-	-	-	-	-	-	-	-	1,605,660	-	-	Apr-21
P35556 - Avian Protection Program	1,536,398	1,522,395	-	-	14,003	-	-	-	-	-	1,536,398	-	-	Monthly
P14757 - Underground Locating	1,514,169	1,514,169	-	-	-	-	-	-	-	-	1,514,169	-	-	Monthly
P37049 - Line Crew Truck Stock Materials	1,503,277	1,503,277	-	-	-	-	-	-	-	-	1,503,277	-	-	Monthly
P36641 - Oil Spill Containment Modifications	1,389,792	-	1,389,792	-	-	-	-	-	-	-	1,389,792	-	-	Various
P36462 - EV Charging Network Expansion	1,381,444	1,381,444	-	-	-	-	-	-	-	-	1,381,444	-	-	Multiple 2019 2020
P36530 - Substation upgrades for BNRG Solar	1,309,840	-	1,309,840	-	-	-	-	-	-	-	1,309,840	-	-	Apr-19
P36551 - Kelley Point Switch Replacement	1,248,304	-	1,248,304	-	-	-	-	-	-	-	1,248,304	-	-	Dec-19
P36322 - King City - Substation Upgrades	1,206,347	1,201,580	4,766	-	-	-	-	-	-	-	1,206,347	-	-	Nov-19
P35349 - Dist Line Sys - Equip Replacement	1,199,869	1,097,146	-	-	102,569	153	-	-	-	-	1,199,869	-	-	Monthly
P36710 - Fairview Substation Upgrades	1,128,667	-	1,128,667	-	-	-	-	-	-	-	1,128,667	-	-	May-20
P36730 - Harrison Sub Temp H Install SE PDX	1,087,957	1,087,957	-	-	-	-	-	-	-	-	1,087,957	-	-	Feb-20
P36497 - 3G Meter Replacement Project	1,087,739	-	-	-	-	1,087,739	-	-	-	-	1,087,739	-	-	Monthly
P35727 - Malin Relay Replacement	1,062,481	-	1,062,481	-	-	-	-	-	-	-	-	1,062,481	-	Dec-18
P36563 - Battery Safety Improvements	862,508	425,060	437,447	-	-	-	-	-	-	-	862,508	-	-	Various
P36372 - Bethany-Springville Feeder Ext.	850,973	850,973	-	-	-	-	-	-	-	-	850,973	-	-	Dec-19
P37094 - Replace SCADA RTU with SER	850,950	-	850,950	-	-	-	-	-	-	-	-	850,950	-	Dec-21
P35941 - OG: Switchyard Upgrade	828,918	-	828,918	-	-	-	-	-	-	-	-	828,918	-	Dec-18
P36856 - Malin Substation - Security	823,674	-	823,674	-	-	-	-	-	-	-	-	823,674	-	Feb-20
P35096 - Dist Customer Line Construction	758,267	1,411,804	-	-	(268,922)	(384,615)	-	-	-	-	758,267	-	-	Monthly
P35149 - Colstrip Transmission NW Energy	722,876	-	722,876	-	-	-	-	-	-	-	-	722,876	-	Various
P36584 - Replace Laminated Poles & Lights	656,347	656,347	-	-	-	-	-	-	-	-	656,347	-	-	Monthly
P35995 - UG Core Cable Replacement	645,265	645,265	-	-	-	-	-	-	-	-	645,264	-	-	Monthly
P36460 - Install Bus Charging Stations	630 425	630 425	-	-	-	-	-	-	-	-	630 425	-	-	Sep-19
P36166 - Orient sub: Capacity Addition	609,052	(280,537)	889,589	-	-	-	-	-	-	-	609,052	-	-	Dec-18
P37121 - Durham Substation Seperation	539,778	-	539,778	-	-	-	-	-	-	-	539,778	-	-	Nov-21
P36378 - Centennial Substation Upgrades	524,419	524,419	-	-	-	-	-	-	-	-	524,419	-	-	Jun-19
P36170 - OHSU Infrastructure Upgrades	516,441	516,058	-	-	382	-	-	-	-	-	516,440	-	-	Various
Total	**1,566,276,915**	**809,107,458**	**351,668,550**	**215,198,605**	**67,823,834**	**53,463,074**	**27,383,567**	**17,449,015**	**16,194,961**	**7,987,851**	**1,109,503,864**	**172,559,092**	**284,213,999**	

August 20, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 312
Dated August 6, 2021

Request:

Please see Table 1 on PGE / 800, Bekkedahl – Jenkins / 4.

a. For any of the items that make up this table and where applicable, please provide all change orders PGE issued throughout the construction of these projects. This is an **ongoing request** – please send additional change orders and associated narrative as additional change orders occur, until a final order is issued in this case.

Response:

PGE objects to this request on the basis that it is vague and unduly burdensome. Subject to and without waiving its objection PGE responds as follows:

See PGE's response to OPUC Data Request No. 311, Attachment 311-A for a listing of all project numbers included in the above referenced Table 1. PGE's Response to OPUC Data Request No. 198, Attachment 198-A provides the project justification forms for these projects, which includes the changes to both definition and scope of the project from project inception to present.

August 20, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 326
Dated August 6, 2021

Request:

For each of the projects the Company is requesting cost recovery for in Exhibit 801:

a. Please provide itemized costs of each project in Excel format with cell formulae intact.
b. Please indicate which of these projects have been previously acknowledged or not in an Oregon IRP, and in which Commission Order it was acknowledged or not acknowledged.
c. If any of these projects were acknowledged in an IRP, please provide the difference in costs between what was projected in an IRP and what actual costs the Company is asking recovery for.
d. Please itemize and provide a narrative justifying each loading associated with a cost escalation in part c.
e. Has the Company obtained all the required approvals for each of these projects (i.e., CPCNs and land use permits)? If not, please provide a list of approvals still required for construction of each of these projects and the anticipated timeline for a decision.
f. Please provide any and all interconnection studies associated with these projects (e.g., System Impact Study, Feasibility Study, and Facilities Study).

Response:

a. Attachment 326-A provides the requested information.
b. None of the projects were acknowledged in an Oregon IRP because they address issues on the PGE local transmission system, not the regional transmission grid.
c. Not applicable.
d. Not applicable.
e. All required approvals for each project have been received.
f. There are no interconnection studies associated with any of these projects.

OPUC DR 326

Integrated Operations Center (IOC)

Charge	Cost
Outside Services	167,430,228
Materials	30,992,752
AFUDC	12,502,531
Internal Labor (Loaded)	2,253,598
Taxes & Fees	1,926,027
Non-Labor Overheads	63,334
Software	30,000
Other Business Expenses	5,540
Total	**215,204,009**

Butler Substation Project

Charge	Cost
Outside Services	31,782,280
Internal Labor (Loaded)	22,342,090
Materials	13,730,556
AFUDC	2,413,718
Taxes & Fees	205,775
Non-Labor Overheads	93,905
Other Business Expenses	24,819
Rents and Lease	7,533
Total	**70,600,676**

Harborton Reliability Project Phase 1

Charge	Cost
Outside Services	22,987,599
Internal Labor (Loaded)	20,695,464
Materials	8,256,196
AFUDC	4,235,185
Taxes & Fees	506,074
Non-Labor Overheads	191,636
Rents and Lease	72,486
Other Business Expenses	60,254
Total	**57,004,894**

Blue Lake Phase II Project

Charge	Cost
Outside Services	15,559,493
Internal Labor (Loaded)	13,265,003
Materials	6,198,358
AFUDC	1,644,797

Non-Labor Overheads	120,882
Taxes & Fees	67,398
Other Business Expenses	38,649
Rents and Lease	34,561
Total	**36,929,141**

Marquam Substation Project

Charge	Cost
Outside Services	21,445,333
Materials	9,199,297
Internal Labor (Loaded)	2,831,314
AFUDC	1,390,711
Non-Labor Overheads	340,979
Rents and Lease	75,064
Other Business Expenses	65,617
Taxes & Fees	24,661
Software	270
Total	**35,373,245**

Unjacketed Cable Replacement Program

Charge	Cost
Outside Services	19,076,857
Internal Labor (Loaded)	12,689,940
Materials	1,720,829
Taxes & Fees	7,141
Non-Labor Overheads	1,802
Other Business Expenses	59
Total	**33,496,628**

Brookwood Substation Conversion Project

Charge	Cost
Materials	9,355,630
Outside Services	7,586,288
Internal Labor (Loaded)	5,208,949
AFUDC	1,381,771
Taxes & Fees	35,879
Non-Labor Overheads	20,248
Rents and Lease	11,039
Other Business Expenses	8,359
Total	**23,608,162**

Helvetia Substation Project

Charge	Cost
Outside Services	10,571,533
Materials	9,886,700
Internal Labor (Loaded)	1,210,849

AFUDC	786,150
Non-Labor Overheads	43,741
Other Business Expenses	31,079
Taxes & Fees	29,383
Rents and Lease	4,056
Total	**22,563,491**

Rock Creek Substation

Charge	Cost
Outside Services	9,202,593
Internal Labor (Loaded)	7,637,888
Materials	4,018,086
AFUDC	1,709,935
Taxes & Fees	241,171
Non-Labor Overheads	74,315
Other Business Expenses	8,051
Rents and Lease	729
Total	**22,892,767**

Roseway Substation Project

Charge	Cost
Outside Services	6,926,615
Internal Labor (Loaded)	6,342,366
Materials	5,218,404
AFUDC	1,506,001
Taxes & Fees	126,664
Non-Labor Overheads	88,665
Rents and Lease	25,260
Other Business Expenses	9,871
Total	**20,243,845**

Division Transit Project

Charge	Cost
Outside Services	11,913,975
Internal Labor (Loaded)	8,315,996
Materials	671,939
Taxes & Fees	148,800
Non-Labor Overheads	6,795
Other Business Expenses	669
CIAC	(1,750,379)
Total	**19,307,795**

PCB Transformer Replacement Project

Charge	Cost
Internal Labor (Loaded)	7,725,435
Outside Services	6,975,315

Materials	3,487,557
Non-Labor Overheads	93,630
Taxes & Fees	59,063
Other Business Expenses	5,460
CIAC	(6,229)
Total	**18,340,231**

Field Voice Communication System Project

Charge	Cost
Outside Services	8,414,334
Materials	5,524,088
Internal Labor (Loaded)	3,107,190
Non-Labor Overheads	287,123
Other Business Expenses	73,047
AFUDC	34,065
Rents and Lease	5,538
Software	3,699
Total	**17,449,085**

McGill Substation Project

Charge	Cost
Internal Labor (Loaded)	6,450,340
Materials	4,159,810
Outside Services	4,335,623
AFUDC	1,712,726
Non-Labor Overheads	212,135
Rents and Lease	124,268
Other Business Expenses	116,049
Taxes & Fees	106,019
Total	**17,216,969**

Field Area Network (FAN)

Charge	Cost
Outside Services	6,458,544
Materials	5,119,418
Internal Labor (Loaded)	4,221,348
Non-Labor Overheads	152,055
AFUDC	84,175
Other Business Expenses	79,298
Software	68,450
Rents and Lease	6,004
Taxes & Fees	5,698
Total	**16,194,990**

Horizon VWR3 Project

Charge	Cost

Internal Labor (Loaded)	4,839,426
Materials	4,419,320
Outside Services	3,207,442
AFUDC	360,793
Non-Labor Overheads	182,354
Other Business Expenses	96,445
Taxes & Fees	77,542
Rents and Lease	75,778
Total	**13,259,100**

Silverton Capacity Addition Project

Charge	Cost
Internal Labor (Loaded)	3,942,367
Materials	3,355,396
Outside Services	3,105,051
AFUDC	338,580
Non-Labor Overheads	105,543
Other Business Expenses	32,501
Rents and Lease	17,530
Taxes & Fees	9,040
Total	**10,906,007**

Willbridge Substation Project

Charge	Cost
Internal Labor (Loaded)	4,688,218
Outside Services	2,985,607
Materials	1,770,733
AFUDC	931,225
Non-Labor Overheads	71,323
Taxes & Fees	56,598
Other Business Expenses	48,752
Rents and Lease	43,920
Total	**10,596,376**

Shute Capacity Addition Project

Charge	Cost
Materials	8,224,489
Internal Labor (Loaded)	787,466
Outside Services	660,084
AFUDC	311,021
Taxes & Fees	16,300
Non-Labor Overheads	6,831
Other Business Expenses	18
Total	**10,006,209**

August 25, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Supplemental Response to OPUC Data Request 334
Dated August 6, 2021

Request:

For each project in exhibit 801 where the Company determined that additional capacity was needed to support load service, please provide a narrative explanation of how the Company forecasted growing need or load for each particular project. Please provide all applicable distribution or transmission planning documents demonstrating forecasted load growth.

Initial Response (dated August 20, 2021):

Confidential Attachment 334-A contains documentation discussing the following projects listed in Exhibit 801:

- Harborton Reliability Project
- Blue Lake Phase II Project
- Marquam Substation Project
- Rock Creek Substation Project
- Roseway Substation Project
- McGill Substation Project
- Horizon VWR3 Project
- Silverton Capacity Addition Project
- Willbridge Substation Project
- Shute Capacity Addition Project
- Brookwood Substation Conversation Project (addressed in the Hillsboro Reliability Project documentation)

The Butler Substation Project and Helvetia Substation Project did not have white papers developed due to a large amount of load growth coming online during the short amount of time that was required for the implementation of these projects. These projects were expedited as a result.

Confidential Attachment 334-A contains protected information and is subject to General Protective Order No. 21-206.

Revised Response (dated August 25, 2021):

Confidential Attachment 334-A contains documentation discussing the following projects listed in Exhibit 801:

- Harborton Reliability Project
- Blue Lake Phase II Project
- Marquam Substation Project
- Rock Creek Substation Project
- Roseway Substation Project
- McGill Substation Project
- Silverton Capacity Addition Project
- Willbridge Substation Project
- Shute Capacity Addition Project
- Brookwood Substation Conversation Project (addressed in the Hillsboro Reliability Project documentation)

Highly Confidential Attachment 334-B contains documentation discussing Horizon VWR3 Project.

The Butler Substation Project and Helvetia Substation Project did not have white papers developed due to a large amount of load growth coming online during the short amount of time that was required for the implementation of these projects. These projects were expedited as a result.

Confidential Attachment 334-A contains protected information and is subject to General Protective Order No. 21-206.

Highly Confidential Attachment 334-B contains protected information and is subject to Modified Protective Order No. 21-237.

September 3, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 498
Dated August 20, 2021

Request:

Regarding the estimated $350 million cost to provide "the needed seismic upgrades designs for 3WTC" referenced at PGE /800, Bekkedahl – Jenkins /15, please provide all support for this estimate.

Response:

Confidential Attachment 498-A provides the requested information. The referenced testimony incorrectly stated the estimated cost to provide needed seismic upgrades for 3 World Trade Center (WTC) as $350 million. The correct number is $304 million, as shown in Confidential Attachment 498-A. Confidential Attachment 498-A provides the following:

- Presentation to Finance Committee of the Board of Directors on October 23, 2018 (similar presentations were given to OPUC Staff on May 28, 2019, and August 11, 2020).
- Request for PGE's architect (Dreyfuss+Blackford) to contract with DCW Cost Management to evaluate the cost associated with five construction options.
- Cost estimates provided by Dreyfuss+Blackford using the cost estimates they received from DCW Cost Management. The cost estimate to renovate and provide seismic upgrades to 3WTC is $304 million.

Attachment 498-A contains protected information and is subject to General Protective Order No. 21-206.

September 3, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 507
Dated August 20, 2021

Request:

Please refer to OPUC Order No 19-400:

a. Please provide the projected Residential Exchange benefits estimated in docket No. UM 2031. Please provide all work papers, with cell formulae intact, showing these estimated benefits.

b. Please provide actual Residential Exchange benefits after reclassification. Please provide all work papers, with cell formulae intact, showing calculations of these benefits.

c. If there is a difference between subparts a. and b., please provide a narrative explanation of the differences in Residential Exchange benefits as a result of transmission reclassification in Docket No. UM 2031.

Response:

a. Although PGE believed that the reclassification of assets would result in an increase in the expected Residential Exchange Program (REP) benefit for our customers, PGE did not provide a projection of that increase in UM 2031.

b. PGE's annual REP benefit was approximately $58.9 million from October 1, 2019 to September 30, 2021. The new benefit, starting October 1, 2021 will be approximately $63.1 million annually. Please see attachment 507-A for the work paper provided by BPA calculating the utility REP benefit. Please note, REP benefits are dependent on both the utility average system costs as well as the load for all investor-owned utilities in the Pacific North West and is not solely dependent on the reclassification of PGE assets.

c. See part a, above.

Calculation of Settlement Utility Specific PF Exchange Rates

Results Under Settlement

TOC RAM2022_Errata xls

Initial Allocations

Initial Allocations	ASC	Base PFx	FY 2022 Exchange Load	FY 2023 Exchange Load	Average Exchange Load	Unconstrained Benefits	Scheduled Amount	Refund Amount	Interim Protection Allocation	Refund Cost Allocation	Interim 7(b)(3) Surcharge	Interim Utility PFx	Interim REP Benefits
	a	b	c	d	e=avg(c,d)	f=(a-b)*e	g=contract	h=contract	Σi=Σf - Σh	Σj=h	k=(i+j)/e	l=b+k	m=(a-l)*e
Avista Corporation	62.93	49.54	3,971	3,971	3,971	$ 53,168			$ 35,222	$ -	8.87	58.41	$ 17,945
Idaho Power Company	58.17	49.54	6,857	6,857	6,857	$ 59,159			$ 39,192	$ -	5.72	55.26	$ 19,968
NorthWestern Energy, LLC	68.34	49.54	714	714	714	$ 13,424			$ 8,893	$ -	12.45	62.00	$ 4,531
PacifiCorp	77.61	49.54	9,147	9,147	9,147	$ 256,738			$ 170,083	$ -	18.59	68.14	$ 86,655
Portland General Electric Company	70.09	49.54	8,413	8,413	8,413	$ 172,862			$ 114,517	$ -	13.61	63.15	$ 58,345
Puget Sound Energy, Inc.	67.28	49.54	11,952	11,952	11,952	$ 212,006			$ 140,449	$ -	11.75	61.29	$ 71,557
Clark Public Utilities	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
Franklin	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
Snohomish PUD	55.83	49.72	3,715	3,731	3,723	$ 22,755			$ 15,074		4.05	53.77	$ 7,680
Total			44,770	44,786	44,778	$ 790,110	$259,000	$0	$ 523,430	$0			$ 266,680

rounding to places = -$948	IOU Σ(g)	$ 767,356	$259,000	$259,000	$ 508,356	IOU Σ(j)	IOU REP	$ 259,000
	COU Σ(g)	$ 22,755		$7,680	$ 15,074	COU Σ(j)	COU REP	$ 7,680

IOU Reallocations

IOU Reallocations	Interim REP Benefits	Annual Adjustment	Reallocation Adjustment	Reallocated Benefits	Final Protection Allocation	Final 7(b)(3) Surcharge	Final Utility PFx	Final REP Benefits
	n=m	o=contract	p=below	q=n-o+p	r=f-q	s=r/e	t=b+s	u=(a-t)*e
Avista Corporation	$ 17,945	$ 2,005	$ -	$ 15,941	$ 37,227	9.37	58.92000	$ 15,926
Idaho Power Company	$ 19,968	$ -	$ -	$ 19,968	$ 39,192	5.72	55.26000	$ 19,954
NorthWestern Energy, LLC	$ 4,531	$ -	$ 68	$ 4,598	$ 8,825	12.36	61.90000	$ 4,599
PacifiCorp	$ 86,655	$ -	$ -	$ 86,655	$ 170,083	18.59	68.14000	$ 86,624
Portland General Electric Company	$ 58,345	$ -	$ 870	$ 59,215	$ 113,647	13.51	63.05000	$ 59,226
Puget Sound Energy, Inc.	$ 71,557	$ -	$ 1,067	$ 72,624	$ 139,382	11.66	61.20000	$ 72,671
Total	$ 259,000	$ 2,005	$ 2,005	$ 259,000	$ 508,356			$ 258,999

	FY 2022 REP Benefits	FY 2023 REP Benefits
	v=(a-t)*c	w=(a-t)*d
Avista	$ 15,926	$ 15,926
Idaho Power	$ 19,954	$ 19,954
NorthWestern	$ 4,599	$ 4,599
PacifiCorp	$ 86,624	$ 86,624
Portland	$ 59,226	$ 59,226
Puget Sound	$ 72,671	$ 72,671
IOU REP	$ 258,999	$ 258,999
Clark	$ -	$ -
Franklin	$ -	$ -
Snohomish	$ 7,664	$ 7,697
COU REP	$ 7,664	$ 7,697
Total REP	$ 266,663	$ 266,696
Refund Amt	$ -	$ -
REP Cost	$ 266,663	$ 266,696

IOU Reallocation Adjustments

IOU Reallocation Adjustments	Avista	Idaho	NorthWestern	PacifiCorp	Portland	Puget Sound	Total
	$ 2,005	$ -	$ -	$ -	$ -	$ -	
	p1=o1*(f/Σf)	p2=o2*(f/Σf)	p3=o3*(f/Σf)	p4=o4*(f/Σf)	p5=o5*(f/Σf)	p6=o6*(f/Σf)	p=Σ(p1 p6)
Avista Corporation		$ -	$ -				$ -
Idaho Power Company							$ -
NorthWestern Energy, LLC	$ 68	$ -		$ -	$ -	$ -	$ 68
PacifiCorp		$ -	$ -				$ -
Portland General Electric Company	$ 870	$ -	$ -	$ -			$ 870
Puget Sound Energy, Inc.	$ 1,067	$ -	$ -	$ -	$ -		$ 1,067
	$ 2,005	$ -	$ -	$ -	$ -	$ -	$ 2,005

Determine Rounding Decimal Place

	1	2	3	4	5	6	7	8
Avista Corporation	$ 16,005	$ 15,926	$ 15,941	$ 15,941	$ 15,941	$ 15,941	$ 15,941	$ 15,941
Idaho Power Company	$ 19,680	$ 19,954	$ 19,968	$ 19,968	$ 19,968	$ 19,968	$ 19,968	$ 19,968
NorthWestern Energy, LLC	$ 4,599	$ 4,599	$ 4,598	$ 4,598	$ 4,598	$ 4,598	$ 4,598	$ 4,598
PacifiCorp	$ 86,989	$ 86,624	$ 86,651	$ 86,655	$ 86,655	$ 86,655	$ 86,655	$ 86,655
Portland General Electric Company	$ 58,805	$ 59,226	$ 59,218	$ 59,215	$ 59,215	$ 59,215	$ 59,215	$ 59,215
Puget Sound Energy, Inc.	$ 72,671	$ 72,671	$ 72,623	$ 72,624	$ 72,624	$ 72,624	$ 72,624	$ 72,624
	$ 258,749	$ 258,999	$ 258,999	$ 259,001	$ 259,000	$ 259,000	$ 259,000	$ 259,000
	($250,554)	($948)	($843)	$836	$60	$1	$1	($0)
	999	2	3	4	5	6	7	8

Rate Analysis Model Exchange Resource Cost

[illegible] | [illegible]

		2022	2023	2 22	2023	2022	2023
Av s a Co po at on	1	62 93	62 93	3 971	3 971		
[illegible]	1	58 17	58 17	6 857	6 857	[illegible]	[illegible]
	1	68 34	68 34	714	14		
Pac f Co p	1	77 61	77 61	9 147	9 147		
[illegible]	1	70 09	70 09	8 413	8 413	[illegible]	[illegible]
	1	67 28	67 28	11 952	11 952		
C a k Pub c Ut t es	0	42 14	42 14	0	0		
F ank n	0	0 00	0 00	0	0	-	-
Snohom sh PUD	1						
To a							

Exchange Cost Calculation

Results Under Settlement

Exchange ASCs ($/MWh)	2022	2023	2024	2025	2026	2027
Avista Corporation	$ 62.93	$ 62.93	$ 64.32	$ 64.32	$ 65.67	$ 65.67
Idaho Power Company	$ 58.17	$ 58.17	$ 58.40	$ 58.40	$ 59.21	$ 59.21
NorthWestern Energy, LLC	$ 68.34	$ 68.34	$ 69.47	$ 69.47	$ 69.62	$ 69.62
PacifiCorp	$ 77.61	$ 77.61	$ 78.34	$ 78.34	$ 79.01	$ 79.01
Portland General Electric Company	$ 70.09	$ 70.09	$ 87.52	$ 87.52	$ 94.94	$ 94.94
Puget Sound Energy, Inc.	$ 67.28	$ 67.28	$ 69.32	$ 69.32	$ 74.05	$ 74.05
Clark Public Utilities	$ -	$ -	$ -	$ -	$ -	$ -
Snohomish PUD	$ 55.83	$ 55.83	$ 57.58	$ 57.58	$ 59.89	$ 59.89

Exchange Loads (GWh)	2022	2023	2024	2025	2026	2027
Avista Corporation	3,971	3,971	4,021	4,021	4,031	4,042
Idaho Power Company	6,857	6,857	6,860	6,860	6,919	6,938
NorthWestern Energy, LLC	714	714	715	715	718	720
PacifiCorp	9,147	9,147	9,299	9,299	9,274	9,299
Portland General Electric Company	8,413	8,413	11,072	11,072	11,112	11,143
Puget Sound Energy, Inc.	11,952	11,952	12,080	12,080	12,141	12,174
Clark Public Utilities	0	0	0	0	0	0
Snohomish PUD	3,715	3,731	3,531	3,521	3,521	3,521
	44,770	44,786	47,578	47,568	47,717	47,839

Exchange Resource Cost ($000)	2022	2023	2024	2025	2026	2027
Avista Corporation	$ 249,924	$ 249,924	$ 258,635	$ 258,636	$ 264,738	$ 265,464
Idaho Power Company	$ 398,876	$ 398,876	$ 400,623	$ 400,622	$ 409,687	$ 410,809
NorthWestern Energy, LLC	$ 48,803	$ 48,803	$ 49,648	$ 49,648	$ 50,017	$ 50,153
PacifiCorp	$ 709,911	$ 709,911	$ 728,521	$ 728,521	$ 732,744	$ 734,752
Portland General Electric Company	$ 589,652	$ 589,652	$ 969,005	$ 969,004	$ 1,054,994	$ 1,057,884
Puget Sound Energy, Inc.	$ 804,160	$ 804,160	$ 837,387	$ 837,387	$ 899,040	$ 901,502
Clark Public Utilities	$ -	$ -	$ -	$ -	$ -	$ -
Snohomish PUD	$ 207,384	$ 208,278	$ 203,307	$ 202,752	$ 210,886	$ 210,886
	$ 3,008,711	$ 3,009,604	$ 3,447,126	$ 3,446,569	$ 3,622,106	$ 3,631,450

Exchange Inputs Sheet

Not printed in documentation.

Transmission Cost ($/MWh) 5.55

EntityID	*Exchange ASC ($/MWh)*	2022	2023	2024	2025	2026	2027
10016	Avista Corporation	62.93	62.93	64.32	64.32	65.67	65.67
10205	Idaho Power Company	58.17	58.17	58.40	58.40	59.21	59.21
10262	NorthWestern Energy, LLC	68.34	68.34	69.47	69.47	69.62	69.62
10300	PacifiCorp	77.61	77.61	78.34	78.34	79.01	79.01
10314	Portland General Electric Company	70.09	70.09	87.52	87.52	94.94	94.94
10325	Puget Sound Energy, Inc.	67.28	67.28	69.32	69.32	74.05	74.05
10103	Clark Public Utilities	42.14	42.14	43.34	43.34	45.07	45.07
10183	Franklin						
10354	Snohomish PUD	55.83	55.83	57.58	57.58	59.89	59.89

	Exchange LOADS (aMW)	2022	2023	2024	2025	2026	2027
10016	Avista Corporation	453.4	453.4	457.8	459.0	460.2	461.5
10205	Idaho Power Company	782.8	782.8	781.0	783.1	789.9	792.0
10262	NorthWestern Energy, LLC	81.5	81.5	81.4	81.6	82.0	82.2
10300	PacifiCorp	1044.2	1044.2	1058.7	1061.6	1058.7	1061.6
10314	Portland General Electric Company	960.4	960.4	1260.5	1263.9	1268.5	1272.0
10325	Puget Sound Energy, Inc.	1364.4	1364.4	1375.2	1379.0	1386.0	1389.8
10103	Clark Public Utilities	289.4	289.4	297.0	297.0	297.0	297.0
10183	Franklin	0.0	0.0	0.0	0.0	0.0	0.0
10354	Snohomish PUD	424.0	425.9	402.0	402.0	402.0	402.0

September 1, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 508
Dated August 20, 2021

Request:

Please refer to Order No. 19-400.

a. Have there been any material changes in law or regulation that has impacted PGE's classification approach? If so, please explain why,

Has PGE deviated from the stipulation in its classification approach? If so, please explain why.

Response:

No, to both questions.

September 1, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 509
Dated August 20, 2021

Request:

Please refer to UE 394 / PGE / 200, Tooman – Batzler / 11:

a. Please provide the FERC rate case docket number.
b. Please provide an estimate, if PGE's proposal were to be authorized at FERC, of how costs will increase for i) PGE retail customers, including all customer classes and ii) PGE transmission customers.
c. Please provide all work papers showing cost estimates for subpart b. of this question.

Please provide work papers on how transmission revenue in the forecast for "Other Revenue" would change if PGE's rate proposals were to be authorized by FERC.

Response:

PGE has not completed its preparation of work papers or testimony with which to file a FERC transmission rate case and does not currently expect to make that filing until late 2021. Consequently, there are no data available with which to respond to this request.

October 12, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Revised Response to OPUC Data Request 527
Dated August 20, 2021

Request:

For all Transmission, Distribution, and Transmission & Distribution projects listed under PGE responses to Staff DRs 142 and 143:

a. Please provide all load service request/transmission service request studies associated with these projects.
b. Please provide any other engineering analysis, or similar supporting evidence that justifies construction of these projects.
c. Please provide a narrative explanation of how the Company forecasted growing need or load for each particular project. Please provide all applicable distribution or transmission planning documents, localized load forecasting studies, or similar supporting evidence that justifies construction of these projects. Where these studies have already been provided as part of Staff Data Request 334, please indicate as such.
d. Please provide one-line diagrams of all these projects. Where these studies have already been provided as part of Staff Data Request 329, please indicate as such.

Initial Response (dated September 3, 2021):

a. There are no transmission service requests associated with these projects. To the extent there are "request for service" forms submitted by customers, those contain protected customer-specific information that must be redacted prior to disclosure to protect customers.
b. Attachment 527-A lists the projects contained in PGE's responses to OPUC Data Requests No. 142 and 143; note that certain projects are not included for cost recovery in this rate case and are indicated as such in Attachment 527-A. Attachment 527-A provides references to where the requested information is provided.
c. See part b.
d. See part b.

Revised Response (dated October 12, 2021)

a. There are no transmission service requests associated with these projects. To the extent there are "request for service" forms submitted by customers, those contain protected customer-specific information that must be redacted prior to disclosure to protect customers.

b. Attachment 527-A lists the projects contained in PGE’s responses to OPUC Data Requests No. 142 and 143; note that certain projects are not included for cost recovery in this rate case and are indicated as such in Attachment 527-A. Attachment 527-A provides references to where the requested information is provided.

   Confidential Attachment 527-B provides documentation as referenced in Attachment 527-A.

c. See part b.

d. See part b.

Attachment 527-B contains protected information and is subject to General Protective Order No. 21-206.

FP#	Project Description	Project Justifications Provided in PGE's Response to OPUC Data Request No.:	One-Line Diagrams Provided in PGE's Response to OPUC Data Request No.:
P14628	Replace Failed Underground Cables	**198 Attach A**	**n/a**
P16567	UG FITNES	**198 Attach A**	**n/a**
P17443	T&D Major System Inspect, Replace	**198 Attach A**	**n/a**
P18834	River District Infrastructure - Install Vaults and Conduits	**198 Attach A**	**n/a**
P22449	Colstrip Coal Capital Project	**198 Attach A**	**n/a**
P22771	Pelton Round Butte Mitigation Enhancement Fund	**198 Attach A and 261**	**n/a**
P23631	Clackamas Protection Mitigation Enhancement	**198 Attach A and 261**	**n/a**
P23970	Corporate Strategic Fiber Project	**198 Attach A**	**n/a**
P24995	Pelton Round Butte Mitigation Enhancement Fund	**198 Attach A and 261**	**n/a**
P35085	Substation Fitness	**198 Attach A**	**n/a**
P35172	PSES - Generation Fitness Fund	**198 Attach A and 277**	**n/a**
P35228	Clackamas PME Road Fund	**198 Attach A and 280**	**n/a**
P35349	Dist Line Sys - Equip Replacement	**198 Attach A**	**n/a**
P35484	Repl Trans Structures & Insulators	**198 Attach A**	**n/a**
P35556	Avian Protection Program	**198 Attach A**	**n/a**
P35565	PSES - Generation Site Paving	**198 Attach A**	**n/a**
P35572	New Rock Creek Substation Construction	**198 Attach A, 332 Attach A and 334 Attach A**	**329 Attach A**
P35591	As-Built Drawings - Generation	**198 Attach A**	**n/a**
P35679	Marquam Substation Construction	**198 Attach A, 332 Attach A and 334 Attach A**	**329 Attach A**
P35802	Horizon Substation Phase II Project	**198 Attach A, 332 Attach A and 527 Attach B**	**332 Attach A and 527 Attach B**
P35834	Round Butte Transmission Upgrades	**198 Attach A**	***cost recovery for project not included in rate case***
P35846	CPP Switch Replacement	**198 Attach A**	**n/a**
P35890	Purchase Distribution Transformers	**198 Attach A**	**n/a**
P35892	Purchase Customer Meters	**198 Attach A**	**n/a**
P35894	Communications Fitness	**198 Attach A**	**n/a**
P35914	Substation Fitness Project - Replace, Repair and Upgrade Agi	**198 Attach A**	**n/a**
P35924	Distribution System Construction	**198 Attach A**	**n/a**
P35925	Distribution Line Construction	**198 Attach A**	**n/a**
P35938	Field Voice Communications System	**198 Attach A and 332 Attach A**	**n/a**
P35959	West Side Hydro Structural/Reliability Upgrade	**198 Attach A, 262 and 286**	**n/a**
P35995	Downtown UG Core Cable Replacement	**198 Attach A**	**n/a**
P36039	Harborton Reliability Project	**198 Attach A, 332 Attach A and 334 Attach A**	**329 Attach A**
P36042	Tektronix Substation Upgrade	**198 Attach A, 527 Attach B** *"St Marys-Tektronix"*	
P36056	Upgrade and Add Revenue Quality Meters	**198 Attach A**	**n/a**
P36061	Beaver Generator Rewind Program	**198 Attach A and 263**	**n/a**
P36089	Transmission Pole Inspection and Replacement	**198 Attach A**	**n/a**
P36100	Bethel to Round Butte Fiber Optic Communication Project	**198 Attach A and 264**	**n/a**
P36101	Substation Communication Upgrade	**198 Attach A and 265**	**n/a**
P36105	Dispatchable Standby Generation (DSG)	**198 Attach A and 281**	**n/a**
P36116	Wind Generation Fitness Program	**198 Attach A**	**n/a**
P36134	Hydro Control System Upgrade	**198 Attach A and 266**	**n/a**
P36167	Repower Faraday Units 1-5	**198 Attach A**	**n/a**
P36175	Customer Underground Primary Service	**198 Attach A**	**n/a**
P36209	Silverton Capacity Addition	**198 Attach A, 332 Attach A and 334 Attach A**	**329 Attach A**
P36224	Identity Management and Access Control Software System U	**198 Attach A**	**n/a**
P36229	McGill Substation Capacity Additions	**198 Attach A, 332 Attach A and 334 Attach A**	**329 Attach A**
P36235	Install Low OH Services Guarding	**198 Attach A**	**n/a**
P36270	Roseway Substation Expansion	**198 Attach A, 332 Attach A and 334 Attach A**	**329 Attach A**
P36285	Purchase T&D - Tools & Lab Equipment	**198 Attach A**	**n/a**
P36322	King City - Substation Upgrades	**198 Attach A and 527 Attach B**	**527 Attach B**
P36324	Garden Home Substation Upgrade	**198 Attach A and 527 Attach B**	**527 Attach B**
P36334	Sherwood Security Upgrades	**198 Attach A**	**n/a**
P36337	Mist Natural Gas Storage	**198 Attach A and 267**	**n/a**
P36341	St. Mary's West Substation System Protection Upgrade	**198 Attach A and 527 Attach B** *"St Marys Battery"*	***cost recovery for project not included in rate case***
P36373	Blue Lake Substation Upgrade	**198 Attach A and 332 Attach A and 334 Attach A**	**329 Attach A**
P36378	Centennial Substation Upgrades	**198 Attach A and 527 Attach B**	**527 Attach B**
P36391	Willbridge Substation Conversion	**198 Attach A, 332 Attach A and 334 Attach A**	**329 Attach A**
P36394	Vintage Vehicle Replacement II	**198 Attach A and 275**	**n/a**
P36400	Enablon Software Upgrade	**198 Attach A**	**n/a**
P36407	Development Operations Automation	**198 Attach A**	**n/a**
P36417	Replace or Rewind Failed Transformers	**198 Attach A and 268**	**n/a**
P36422	Evergreen Property Land Purchase	**198 Attach A**	**n/a**
P36439	Gresham Substation Rebuild	**198 Attach A**	***cost recovery for project not included in rate case***
P36444	Upgrade Excitation System	**198 Attach A and 269**	**n/a**
P36462	Electric Vehicle Charging Station Network Expansion	**198 Attach A**	**n/a**
P36464	Facilities Asphalt R&R Project	**198 Attach A and 284**	**n/a**
P36496	As-Built Drawings	**198 Attach A**	**n/a**
P36501	Build Integrated Operations Center	**198 Attach A and 332 Attach A**	**n/a**
P36503	Enterprise Performance Monitoring	**198 Attach A**	**n/a**
P36510	Carty Water Treatment System Upgrade	**198 Attach A and 270**	**n/a**
P36522	Distribution Automation Project	**198 Attach A**	**n/a**
P36527	Tapline Reliability Improvement Program (TRIP) Implementat	**198 Attach A**	**n/a**
P36537	Unjacketed Cable Replacement Prgrm	**198 Attach A and 332 Attach A**	**n/a**
P36541	T&D/Generation Key Metric Software Development	**198 Attach A**	**n/a**
P36543	PRC-002 Protection Upgrades	**198 Attach A**	**n/a**
P36545	Tree Wire Installment Program	**198 Attach A**	**n/a**
P36550	Small Generator/Qualified Facility (QF) Interconnection	**198 Attach A**	**n/a**

P36564	Stephens Substation Conversion	**198 Attach A and 530 Attach A**	***cost recovery for project not included in rate case***
P36571	Marquam Substation Feeder Addition	**198 Attach A**	
P36582	Canyon Substation Upgrade	**198 Attach A**	
P36583	Strategic Spare Substation Equipment Purchase	**198 Attach A**	**n/a**
P36587	Upgrade Physical Access Control System	**198 Attach A**	**n/a**
P36599	Install Load Bank	**198 Attach A**	**n/a**
P36602	RB: Replace Hatchery Chiller System	**198 Attach A and 285**	**n/a**
P36617	South Milliken Distribution Line Rebuild	**198 Attach A and 528 Attach A**	***cost recovery for project not included in rate case***
P36628	Replace Exhaust Frame and Diffuser	**198 Attach A**	**n/a**
P36640	Port Westward Turbine Upgrade	**198 Attach A and 271**	**n/a**
P36641	Oil Spill Containment Modifications	**198 Attach A**	**n/a**
P36656	Energy Storage System	**198 Attach A and 272**	**n/a**
P36667	Residential Flexible Pricing Implementation	**198 Attach A**	**n/a**
P36679	Orenco Substation Rebuild	**198 Attach A**	***cost recovery for project not included in rate case***
P36680	Brookwood Substation Conversion	**198 Attach A, 332 Attach A and 334 Attach A**	**329 Attach A**
P36683	Distributed Control Software Upgrade	**198 Attach A**	**n/a**
P36693	Build Helvetia Substation	**198 Attach A and 332 Attach A**	**329 Attach A**
P36706	Human Resources System Implementation	**198 Attach A**	**n/a**
P36708	Build Butler Substation	**198 Attach A and 332 Attach A**	**329 Attach A**
P36711	Purchase GIS Software Enterprise Licenses	**198 Attach A**	**n/a**
P36716	Arleta-Holgate Conversion	**198 Attach A and 530 Attach A**	**530 Attach A**
P36723	Field Area Network Project	**198 Attach A and 332 Attach A**	**n/a**
P36727	Energy Storage, Microgrid	**198 Attach A**	**n/a**
P36732	Carty/Boardman Separation Project	**198 Attach A and 273**	**n/a**
P36742	River Mill Unit 3 Rewind	**198 Attach A**	**n/a**
P36762	Milliken Tower Reinforcement	**198 Attach A**	**n/a**
P36763	Horizon Substation Transformer Installation	**198 Attach A and 334 Attach B**	**329 Attach A**
P36766	Remote Imaging Project	**198 Attach A**	**n/a**
P36770	Street and Area Light Construction	**198 Attach A**	**n/a**
P36818	Verint Voice Recording Tool Replacement	**198 Attach A**	**n/a**
P36829	Build Sherwood Training Center	**198 Attach A and 274**	**n/a**
P36836	BR: Beaver Modernization	**198 Attach A and 276**	**n/a**
P36855	Wheatridge Renewable Energy Facility	**198 Attach A**	**n/a**
P36861	Division Transit Project (DTP)	**198 Attach A and 332 Attach A**	**n/a**
P36867	Remote Disconnect Project	**198 Attach A**	**n/a**
P36868	Shute Capacity Addition	**198 Attach A, 332 Attach A and 334 Attach A**	**329 Attach A**
P36879	Advanced Distribution Management System Upgrade	**198 Attach A**	**n/a**
P36907	Reconductor Murrayhill-St Mary's	**198 Attach A**	
P36910	Outer Div Multi-Modal Safety Proj	**198 Attach A**	**n/a**
P36911	Wildfire Mitigation	**198 Attach A**	**n/a**
P36913	Trans. Line Clearance Mitigation	**198 Attach A**	**n/a**
P36921	PGE/DTNA HD charging Demonstration	**198 Attach A**	**n/a**
P36959	2022 Distribution Blanket Projects	**198 Attach A**	**n/a**
P36973	Upgrade IVR System	**198 Attach A**	**n/a**
P37017	Facilities Upgrades-EV Readiness	**198 Attach A**	**n/a**
P37046	T&D Asset Relocation	**198 Attach A**	**n/a**
P37047	Joint Pole Construction	**198 Attach A**	**n/a**
P37048	Outage or Emergency Replacement	**198 Attach A**	**n/a**
P37049	Line Crew Truck Stock Materials	**198 Attach A and 282**	**n/a**
P37061	OH FITNES Transmission	**198 Attach A**	**n/a**
P37085	2021 Infrastructure Fitness Blanket	**198 Attach A**	**n/a**
P37094	Replace SCADA RTU with SER	**198 Attach A**	**n/a**
P37095	SCADA Replacement - Grizzly Substation	**198 Attach A and 283**	**n/a**
P37099	Restore Beaver GT Unit 5	**198 Attach A**	**n/a**
P37103	ODOT OR213/SE82nd Foster to Lindy	**198 Attach A**	**n/a**
P37106	Mobile 2.0	**198 Attach A**	**n/a**
P37108	Proactive Outage (Software)	**198 Attach A**	**n/a**
P37109	Customer Data Centers	**198 Attach A**	**n/a**
P37110	Restore Bethel-RB 230 kV Line	**198 Attach A**	
P37111	Supply Chain Evolution	**198 Attach A**	**n/a**
P37113	Web Next Gen 2.0 Phase II	**198 Attach A**	**n/a**
P37114	Project BaT	**198 Attach A**	**n/a**
P37118	WSH:Restore Facilities post-fire	**198 Attach A**	**n/a**
P37121	Durham Substation Separation	**198 Attach A**	
P37131	2021 Desktop Fitness	**198 Attach A**	**n/a**
P37133	2021 Network Fitness	**198 Attach A**	**n/a**
P37135	2021 Server Storage Fitness	**198 Attach A**	**n/a**
P37143	Credit Remote Connect Meters	**198 Attach A**	**n/a**
P37155	Time of Day	**198 Attach A**	**n/a**
P37157	Mobile 3.0	**198 Attach A**	**n/a**
P37175	Electronic Payment Redesign Phase 2	**198 Attach A**	**n/a**

September 3, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 532
Dated August 20, 2021

Request:

Please refer to PGE's Attachment to Staff DR 142:

a. Please explain why the Butler Substation is classified as both T&D.
b. Please explain how PGE will or does classify this on its FERC Form 1, and why.

Response:

a. The Butler substation is a 115 kV breaker-and-one-half substation that is networked into the transmission system with four normally closed 115 kV lines: Butler #1, Butler #2, Orenco, and St Marys. The distribution transformers are radial to the 115 kV system; therefore, this equipment and everything downstream is classified as distribution. Attachment 532-A provides further information.

b. PGE will classify the assets for Butler Substation as identified in part (a), following the criteria in Order No. 19-400.

   Transmission assets will be recorded in FERC Account 353 for substation equipment and FERC Accounts 354-355 for the transmission lines.

   Distribution assets will be recorded in FERC Account 362 for substation equipment and FERC Accounts 364-367 for distribution feeders.

   Common assets (such as land, fencing, etc.) will be split between transmission and distribution accounts based on the ratio of original cost of the transmission and distribution assets in that substation.

Substation	Voltages at the Substation (kV)	All Substation Assets < 100 kV? (Non-Gen Tie)	All Substation Assets > 100 kV? (Non-Gen Tie)	Substation Assets < 100 kV AND > 100 kV? (Non-Gen Tie)	115 kV Radial/Idle Equipment, Including Distribution Transformers? (Non-Gen Tie)	Gen Tie Facilities?	Three or more *Normally Closed* 115 kV + Transmission Line Sources? (Non-Gen Tie)	Substation Common Assets Classification
Butler	115, 34.5	NO	NO	YES	YES	NO	YES	T & D

September 27, 2019

TO: Nadine Hanhan
Public Utility Commission of Oregon

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 2031
PGE Response to OPUC Data Request No. 046
Dated September 20, 2019

Request:

Considering Staff DR 46 Attachment A showing BPA RDS 11, Table 2.4.11 Rate Directive Step, Calculation of Utility Specific PF Exchange Rates and REP Benefits, where the first page thereof reflects a Test Period of October 2017 to September 2019, and the second page reflects a Test Period of October 2019 to September 2021, and UM 2031 / PGE 100, Edmonds – Galaway4 – Paragraph A – third bullet from top – An expected increase in the Residential Exchange Program benefits from the Bonneville Power Administration, please provide a spreadsheet with formulas and cell references intact and supporting narrative showing against the fiscal year REP benefits depicted on Attachment A lower right corner for Portland General Electric.

a. Annual REP benefits as best projected by PGE annually from now through 2030, and NPV thereof.
b. Annual REP benefits increase against benchmark a above, as best projected by PGE annually from now through 2030, and NPV thereof were PGE's request for asset reclassification approved as filed.
c. Annual REP benefits increase against benchmark a above, as best projected by PGE annually from now through 2030, and NPV thereof were PGE's request for asset reclassification approved for lines of 100 kV and greater, and for transformers with both primary and secondary voltage of 100 kV or greater, but approval denied for lines under 60 kV and also denied for transformers with secondary voltage under 60 kV except when PGE determines that the 60 kV and lower voltage assets are both part of the Bulk Electric System (BES) and subject to NERC reliability regulation.
d. Narrative itemizing and explaining the assumptions necessary for PGE to make the above calculations.
e. Narrative explaining the zero-sum or common-pie aspect of the BPA Residential Exchange Program and PGE's estimation of what portion of increased PGE Res-

X benefits would come at the expense of Oregon ratepayers of each of PacifiCorp and Idaho Power respectively.

f. Narrative sharing PGE's best understanding of how and to what extent changes in transmission assets on filed FERC Form 1's of each of Avista and Idaho Power between the time periods of Attachment A Page 1 and Page 2 increased Avista and Idaho Power portion of available Res-X benefits at the expense of PGE and its customers.

g. Narrative explaining how the Res-X benefit translates to PGE ratepayer benefit and to what extent these benefits are dependent on the above assumptions holding true relative to other Res-X participants.

Response:

PGE objects to this request on the grounds that calls for speculation and new analysis. Without waving this objection, PGE responds as follows:

a. The Settlement Agreement with the Bonneville Power Administration (BPA) runs through September 31, 2028, which is the end of the 2028 BPA fiscal year. Projecting REP benefits beyond that date would require considerable speculation. Consequently, PGE is providing projected benefits for the contract period. Attachment 046-A, Tab "A_Current ASC Benefits" provides the requested information.

b. See Attachment 046-A, Tab "B_ASC Benefits As-Filed."

c. See Attachment 046-A, "Tab C_ASC Benefits >100 kV."

d. The results included in Attachment A assume that average system costs (ASCs) and qualifying load for Northwest IOU's, except for PGE, remain constant through BPA fiscal year 2028 and that the residential exchange program (REP) settlement amounts increase per the REP settlement with BPA. The only changes are to increase PGE's transmission net book plant amount and annual O&M expense to account for the facilities reclassified from distribution to transmission, and to decrease net book and O&M for distribution by the same amounts. The result of those adjustments is to increase PGE's ASC in 2022 to account for an increase in PGE's transmission rate base, and again in 2024 to account for an increase in PGE's transmission O&M. In addition, we assume that PGE will file its 2019 FERC Form 1 to reflect asset reclassification from distribution to transmission.

   In addition to the above assumptions, while not an exhaustive list, the following items are held constant for each IOU: cost of capital, capital structure, net sales for resales, wheeling expense and revenue, market prices for electricity and natural gas, tax rates, distribution losses, salaries, load forecasts and New Large Single Loads.

Finally, PGE used its authorized Return on Equity as approved in its most recent general rate case, UE 335, to calculate net present values (NPVs).

e. PGE requested reclassification of certain distribution assets from distribution to network transmission based on engineering analysis by PGE and nFront. An increase in REP benefits to PGE customers is a secondary benefit of reclassification and is not the reason for requesting the reclassification. Additionally, PGE does not think that any impact on REP benefits for customers of other Northwest IOUs is relevant to this filing.

   The Settlement Agreement with BPA includes a schedule of REP benefits through BPA fiscal year 2028 to Northwest IOUs with benefits increasing over time. Benefits are allocated among the IOU's for their residential and small farm customers based on the respective utility's ASC and qualifying load. The Rate Analysis Model performs iterations until the aggregate benefits equal the REP scheduled amount. Consequently, changes in the ASC and/or qualifying load of any utility impact the share of the REP Scheduled Amount received by all of the other IOUs. Under the Settlement Agreement, REP benefits are fixed for each two-year BPA rate period.

   See Attachment 046-A, "Tab D_Comparison" for the potential impacts to PacifiCorp and Idaho Power Company (IPC) REP benefits through BPA 2028 fiscal year. Note that the values for both IPC and PacifiCorp are on a total company basis, and PGE does not know what portion of their respective REP benefits are allocated to customers in Oregon.

f. While PGE has not conducted a thorough review of IPC's or Avista's ASC filings for 2018 and 2020, it appears that their respective increases in REP benefits from 2018 to 2020 are due, at least in part, to increases in their production and transmission rate base. Avista's net production and transmission rate base increased from $1.2 billion to $1.4 billion (a 17.75% increase). IPC's net production and transmission plant increased from $2.3 billion to $4.0 billion (a 75.4% increase). The net impact of increasing production and transmission plant net rate base (and other changes) is that Avista's REP benefits increased from $2.9 million in 2018 and 2019 to $14.6 in 2020 and 2021, while IPC's REP benefits increased from $13.4 million to $22.3 million.

g. REP benefits are a pass-through credit from BPA to residential and small farm customers. PGE collects the REP benefits for its customers and credits customers' bills via PGE Schedule 102. REP funds are held in a balancing account, with any balance earning interest at the modified blended treasury rate in accordance with Commission Order No. 08-263, which is updated annually. The bill credit under Schedule 102 is adjusted periodically to keep the balance relatively low. In addition to the current balance, considerations on whether to adjust the credit include PGE REP benefits as determined in BPA rate cases and forecasts of residential and farm loads. Consequently, actual REP credits to customers depend on actual REP payments from BPA and customer load, not projected REP benefits. To the extent that actual amounts, including investments or reclassification by other IOUs, differ from the assumptions made in responding to this data request, actual REP credits to PGE's customers will also differ. Even if another IOU adds production or transmission costs in the future, such that its ASC increases, PGE's reclassification would still lead to increased benefits for its customers compared to a scenario in which PGE has not reclassified assets. If PGE's transmission assets are not reclassified from distribution to transmission, and reported as such in FERC Form 1, PGE customers' share of REP benefits are not projected to increase.

Benefits Under Current ASC

Year	Scheduled Amount	Exchange ASC	PGE Benefit (Millions)	PGE - NPV (Millions)	PacifiCorp Benefit (Millions)	PacifiCorp - NPV (Millions)	Idaho Power Benefit (Millions)	Idaho - NPV (Millions)
2019	$232,200	$75.76	$66,934	$66,934	$67,750	$67,750	$13,376	$13,376
2020	$245,200	$77.53	$58,927	$53,815	$63,718	$58,190	$22,292	$20,358
2021	$245,200	$77.53	$58,927	$49,146	$63,718	$53,142	$22,292	$18,592
2022	$259,000	$77.53	$62,094	$47,294	$67,540	$51,442	$23,565	$17,948
2023	$259,000	$77.53	$62,094	$43,191	$67,540	$46,979	$23,565	$16,391
2024	$273,600	$77.53	$65,445	$41,572	$71,583	$45,472	$24,912	$15,825
2025	$273,600	$77.53	$65,445	$37,966	$71,583	$41,526	$24,912	$14,452
2026	$286,100	$77.53	$68,285	$36,176	$75,027	$39,748	$26,094	$13,824
2027	$286,100	$77.53	$68,285	$33,038	$75,027	$36,300	$26,094	$12,625
2028	$286,100	$77.53	$68,285	$30,172	$75,027	$33,151	$26,094	$11,530
		Total =	$644,721	$439,304	$698,513	$473,699	$233,196	$154,921

Inputs

REP Settlement Inputs

RAMmodel_REP2020.xls

	Scheduled Benefits	Refund Amounts
2012	182100	76537.617
2013	182100	76537.617
2014	197500	76537.617
2015	197500	76537.617
2016	214100	76537.617
2017	214100	76537.617
2018	232200	76537.617
2019	232200	76537.617
2020	245200	0
2021	245200	0
2022	259000	0
2023	259000	0
2024	273600	0
2025	273600	0
2026	286100	0
2027	286100	0
2028	286100	0

Discount Rate 9.5%

ASC Benefits With Reclassification from Distibution to Transmission for All Assets

Year	Scheduled Amount	Exchange ASC	PGE Benefit (Millions)	PGE - NPV (Millions)	PacifiCorp Benefit (Millions)	PacifiCorp - NPV (Millions)	Idaho Power Benefit (Millions)	Idaho - NPV (Millions)	
2019	$232,200	$75.76	$66,934	$66,934	$67,750	$67,750	$13,376	$13,376	3
2020	$245,200	$77.53	$58,927	$53,815	$63,718	$58,190	$22,292	$20,358	
2021	$245,200	$77.53	$58,927	$49,146	$63,718	$53,142	$22,292	$18,592	
2022	$259,000	$77.59	$64,373	$49,030	$66,745	$50,837	$23,302	$17,748	
2023	$259,000	$77.59	$64,373	$44,776	$66,745	$46,426	$23,302	$16,208	
2024	$273,600	$82.33	$69,387	$44,077	$70,208	$44,598	$24,454	$15,534	
2025	$273,600	$82.33	$69,387	$40,253	$70,208	$40,729	$24,454	$14,186	
2026	$286,100	$82.33	$72,435	$38,375	$73,605	$38,995	$25,587	$13,556	
2027	$286,100	$82.33	$72,435	$35,046	$73,605	$35,612	$25,587	$12,380	
2028	$286,100	$82.33	$72,435	$32,005	$73,605	$32,522	$25,587	$11,306	
		Total =	$669,613	$453,456	$689,907	$468,800	$230,233	$153,243	

2022-2023: ASC benefit includes capital associated with reclassification.
2024-2028: ASC benefit includes capital and O&M associated with reclassification.

Benefits With Reclassification from Distibution to Transmission for Assets > 100 kV

Year	Scheduled Amount	Exchange ASC	PGE Benefit (Millions)	PGE - NPV (Millions)	PacifiCorp Benefit (Millions)	PacifiCorp - NPV (Millions)	Idaho Power Benefit (Millions)	Idaho - NPV (Millions)
2019	$232,200	$75.76	$66,934	$66,934	$67,750	$67,750	$13,376	$13,376
2020	$245,200	$77.53	$58,927	$53,815	$63,718	$58,190	$22,292	$20,358
2021	$245,200	$77.53	$58,927	$49,146	$63,718	$53,142	$22,292	$18,592
2022	$259,000	$77.59	$63,972	$48,725	$66,886	$50,944	$23,347	$17,782
2023	$259,000	$77.59	$63,972	$44,497	$66,886	$46,524	$23,347	$16,240
2024	$273,600	$82.33	$68,706	$43,644	$70,446	$44,749	$24,533	$15,584
2025	$273,600	$82.33	$68,706	$39,857	$70,446	$40,867	$24,533	$14,232
2026	$286,100	$82.33	$71,719	$37,996	$73,856	$39,128	$25,669	$13,599
2027	$286,100	$82.33	$71,719	$34,699	$73,856	$35,733	$25,669	$12,419
2028	$286,100	$82.33	$71,719	$31,689	$73,856	$32,633	$25,669	$11,342
		Total =	$665,301	$451,002	$691,418	$469,660	$230,727	$153,524

2022-2023: ASC benefit includes capital associated with reclassification.
2024-2028: ASC benefit includes capital and O&M associated with reclassification.

$20,580

ASC Benefits With Reclassification from Distibution to Transmission for All Assets

As-Filed

Year	Scheduled Amount	Exchange ASC	PGE Benefit (Millions)	PacifiCorp Benefit (Millions)	Idaho Power Benefit (Millions)
2019	$232,200	75.76	$66,934	$67,750	$13,376
2020	$245,200	77.53	$58,927	$63,718	$22,292
2021	$245,200	77.53	$58,927	$63,718	$22,292
2022	$259,000	77.59	$64,373	$66,745	$23,302
2023	$259,000	77.59	$64,373	$66,745	$23,302
2024	$273,600	82.33	$69,387	$70,208	$24,454
2025	$273,600	82.33	$69,387	$70,208	$24,454
2026	$286,100	82.33	$72,435	$73,605	$25,587
2027	$286,100	82.33	$72,435	$73,605	$25,587
2028	$286,100	82.33	$72,435	$73,605	$25,587

Current ASC Benefits

Year	Scheduled Amount	Exchange ASC	PGE Benefit (Millions)	PacifiCorp Benefit (Millions)	Idaho Power Benefit (Millions)
2019	$232,200	$75.76	$66,934	$67,750	$13,376
2020	$245,200	$77.53	$58,927	$63,718	$22,292
2021	$245,200	$77.53	$58,927	$63,718	$22,292
2022	$259,000	$77.53	$62,094	$67,540	$23,565
2023	$259,000	$77.53	$62,094	$67,540	$23,565
2024	$273,600	$77.53	$65,445	$71,583	$24,912
2025	$273,600	$77.53	$65,445	$71,583	$24,912
2026	$286,100	$77.53	$68,285	$75,027	$26,094
2027	$286,100	$77.53	$68,285	$75,027	$26,094
2028	$286,100	$77.53	$68,285	$75,027	$26,094

Variance

Year	Scheduled Amount	Exchange ASC	PGE Benefit (Millions)	PacifiCorp Benefit (Millions)	Idaho Power Benefit (Millions)
2019	$232,200	$75.76	$0	$0	$0
2020	$245,200	$77.53	$0	$0	$0
2021	$245,200	$77.53	$0	$0	$0
2022	$259,000	$77.53	$2,279	-$795	-$263
2023	$259,000	$77.53	$2,279	-$795	-$263
2024	$273,600	$77.53	$3,942	-$1,375	-$458
2025	$273,600	$77.53	$3,942	-$1,375	-$458
2026	$286,100	$77.53	$4,150	-$1,422	-$507
2027	$286,100	$77.53	$4,150	-$1,422	-$507
2028	$286,100	$77.53	$4,150	-$1,422	-$507

	PGE Benefit (Millions)	PacifiCorp Benefit (Millions)	Idaho Power Benefit (Millions)
Change to Benefit	**$24,892**	**-$8,606**	**-$2,963**

CASE: UE 394
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 703

REDACTED

Exhibits in Support
Of Opening Testimony

October 25, 2021

Staff Exhibit 703 is confidential subject to Protective Order No. 21-206.

CASE: UE 394
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 704

REDACTED

Exhibits in Support
Of Opening Testimony

October 25, 2021

Staff Exhibit 704 is confidential subject to Protective Order No. 21-206.

CASE: UE 394
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 705

REDACTED

Exhibits in Support
Of Opening Testimony

October 25, 2021

Staff Exhibit 705 is confidential subject to Protective Order No. 21-206.

CASE: UE 394
WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 706

REDACTED

Exhibits in Support
Of Opening Testimony

October 25, 2021

Staff Exhibit 706 is highly confidential subject to Modified Protective Order No. 21-237.

CASE: UE 394
WITNESS: NICK SAYEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

REDACTED

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Nicholas (Nick) W. Sayen. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review PGE's investment in an Advanced Distribution Management System (ADMS), ADMS operations and maintenance (O&M), distribution projects, and projects that are a combination of distribution and transmission (referred to collectively as "distribution projects").

Q. How is your testimony organized?

A. My testimony is organized around the following issues, with the final issue including a project-by-project review:

ISSUE 1. ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS) CAPITAL

Q. Please describe ADMS.

A. ADMS is a software system that, combined with hardware in the field, enables real-time visibility into, and management of, the distribution system. Examples include capabilities such as automatic fault location and restoration, optimization around distributed energy resources (DERs), and optimization around flexible loads.

Q. Please summarize the Company's approach to ADMS.

A. PGE is taking a multi-phase approach to ADMS. Phase one is currently underway and scheduled for completion by the end of 2021. Phase one includes the software itself, as well as steps to establishing the software as an operational platform.[1]

Q. Please summarize the Company's proposal.

A. PGE is seeking cost recovery for phase one of ADMS for capital costs of $30.6M and O&M costs of $3.8M.[2]

Q. Please describe Staff's analysis of the Company's ADMS investments.

A. Staff analyzed whether PGE's decision to invest in a $30.6M ADMS was prudent, and whether PGE prudently managed the costs of the project.

Q. Why did PGE invest in ADMS?

1 PGE/800, Bekkedahl-Jenkins/30.
2 PGE/800, Bekkedahl-Jenkins/31.

A. The Company's distribution grid has approximately 700 feeders and approximately 220 substations.[3] The Company currently monitors the distribution grid only indirectly through the transmission system, and through the outage management system (OMS) utilizing customer meters.[4] ADMS will allow PGE to monitor the distribution grid in real time and predict future power flow conditions and system constraints.[5]

PGE identified five key benefits to customers for Phase one of ADMS in testimony. These included: 1) establishing a platform on which to implement applications to manage the distribution system; 2) a real-time view of the state of the distribution system which enables proactive identification and resolution problems; 3) support for the separation of transmission system operator roles from distribution system operator roles; 4) support for migration from paper maps presently used for distribution switching to electronic switching orders; and 5) a "single source of truth" for the as-switched state of the distribution system.[6]

PGE testimony describes the ADMS as a key part of PGE's grid modernization plan, which is "a phased, multi-year and multi-program approach to better maintain and improve reliability and resiliency of the electric grid as new and innovative technologies are adopted by our customers."[7]

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3 PGE/800, Bekkedahl-Jenkins/32.
4 PGE/800, Bekkedahl-Jenkins/32.
5 PGE/800, Bekkedahl-Jenkins/32.
6 PGE/800, Bekkedahl-Jenkins/31.
7 PGE/800, Bekkedahl-Jenkins/12.

Q. What has Staff concluded about the prudence of PGE's decision to invest in ADMS?

A. Staff too has recognized new technologies, customer adoption rates, and evolving resiliency challenges and foresees an eventual transition to a grid that is capable of minimizing the frequency and impact of outages, supporting decarbonization, optimizing system performance, and enabling customers to deploy DERs.[8] Given these evolving dynamics, ADMS' foundational role in managing the distribution system, and finally PGE's prior lack of ADMS, Staff does not challenge the prudence of PGE's decision to invest in ADMS.

Q. What has Staff concluded about the amount of money invested in ADMS?

A. The Company's investment includes 1) capital investment in the ADMS software, and 2) capital investment in ADMS *other* than the software.

Regarding first the capital investment in the software, it is quite impractical to "comparison shop" one ADMS amongst ADMS implemented at other utilities. This is because utility service territories are heterogenous as are the distribution systems serving those territories, and these factors inherently embed any ADMS used to manage those systems with unique characteristics as well. Further complicating comparisons, a utility may choose to equip an ADMS with varying functions and features in varying implementation phases. Because of the impracticality in comparison shopping to evaluate PGE's ADMS

[8] Staff Whitepaper: A Proposal for Electric Distribution System Planning, page 3.

investment, Staff instead focused on the process by which the ADMS was selected, and whether that process was likely to lead to a prudent investment.

Q. What did Staff learn by reviewing this process?

A. To begin review of the selection process Staff noted from PGE testimony that the Company worked with utilities who already implemented ADMS and learned key lessons from the experiences of these utilities.[9] Staff also noted that the Company engaged independent experts to help develop the ADMS program.[10]

Staff submitted discovery to better understand the Company's approach to soliciting ADMS providers, review the solicitation itself, and review responses to the solicitation. Staff also submitted discovery to better understand the Company's approach to evaluating solicitation responses and to review the analysis conducted evaluating the responses. Additionally, Staff submitted discovery to better understand the Company's approach to contracting with the selected ADMS provider, to review the final contract with the selected provider, and to review the final total amount paid to the provider under the contract.

Staff learned that the Company retained a consultant experienced with implementing ADMS at other utilities.[11] The consultant worked with PGE stakeholders to develop the Company's ADMS business requirements and use

[9] PGE/800,Bekkedahl-Jenkins/33.
[10] PGE/800,Bekkedahl-Jenkins/33.
[11] Staff/802, PGE response to Staff DR 468.

cases.[12] These requirements and use cases were utilized to develop a request for proposals.[13] PGE received five responses[14] and evaluated these responses using several thousand criteria.[15] The responses were evaluated by members of the PGE ADMS team.[16] The two responses with the highest score were selected as finalists and invited to present to the PGE project team.[17] From the finalists,**[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was selected as the ADMS provider.

The fees of the received responses ranged from approximately **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**[18] Fees from the finalists ranged from approximately **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**[19] The final total amount paid to the selected ADMS provider by the expected in-service date of December 2021 is expected to be **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**[20] After conducting this review, Staff does not challenge the prudence of PGE's process to select the ADMS, nor the prudence of the amount of money invested in ADMS software.

Q. What about capital investment in ADMS other than the software?

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[12] Staff/802, PGE response to Staff DR 468.
[13] Staff/802, PGE response to Staff DR 468.
[14] Staff/802, PGE response to Staff DR 470.
[15] Staff/802, PGE response to Staff DR 471.
[16] Staff/802, PGE response to Staff DR 471.
[17] Staff/802, PGE response to Staff DR 468.
[18] Staff/803, Confidential PGE response to Staff DR 470, ADMS RFP Evaluations FINAL_Redacted.pdf.
[19] Staff/803, Confidential PGE response to Staff DR 470, ADMS RFP Evaluations FINAL_Redacted.pdf.
[20] Staff/803, Confidential PGE response to Staff DR 832.

A. Staff estimates this amount to be approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** based on subtracting the total paid to the ADMS provider of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from the Company's requested ADMS capital costs of $30.6M.

Staff submitted discovery to better understand the nature and timing and of this investment, requesting a list of projects comprising the $30.6M in capital costs and basic information about each project including the date each project was expected to be placed into service, the FERC account for each project, the final or estimated final cost of each project when placed in service, a brief narrative description of each project, project justification forms, and any engineering analysis, or similar, to justify each project.

The Company's discovery responses explained there was only one funding project for the ADMS capital costs, and provided the in-service date, the FERC accounts, the estimated final cost, a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[21] for the ADMS Project from 2018, a project justification form,[22] and referenced PGE testimony for a narrative description.

Q. Did this information enable evaluation of whether the amount of money invested was prudent?

21 Staff/803, Confidential PGE response to Staff DR 833 Attachment B.
22 PGE provided three versions of the project justification form. The initial version, provided in response to Staff data request 198, was ten pages in length. The second version, provided as a revised response to Staff data request 198, was 15 pages in length. The third version was 17 pages in length.

A. No, unfortunately not. The **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** provided background for the project but was prepared during the planning stage and so did not include actual project information.

The project justification form includes information such as the following (discussed below in the order it was presented in the form):

- Updates from March 2021 and September 2021.[23] The updates include an adjustment to the project schedule, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** but primarily address shifting spending from year-to-year.[24]
- Brief description of alternatives considered,[25] summary of the scope and goals of the project,[26] brief notes on various aspects of the project such as project contingencies and net present value,[27] and description of avoided costs and reduced risk exposure.[28]
- One entry, presumably early in the project, requesting **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of capital to complete phase one of ADMS, laying out spending over 2019, 2020, and 2021, and summarizing the scope and goals of the project.[29]
- Updates from December 2019, April 2020, June 2020, October 2020, and November 2020.[30] These updates include a request for additional

[23] Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Page 1.
[24] Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Page 3.
[25] Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Page 3.
[26] Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Page 5.
[27] Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Page 7.
[28] Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Page 9.
[29] Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Page 13.
[30] Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Pages 13 and 14.

funding, **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]** but primarily address shifting spending from year-to-year.[31]

- Brief notes on various aspects of the project such as why the status quo is not adequate, with a brief description of alternatives considered,[32] project benefits,[33] and dependencies such as relationships to other projects, and other project timelines.[34]

The project justification form does not include information about specific project components or any granular financial information about those, and includes minimal information on the timing of those projects. In sum, Staff was not able to tell what the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of investment was spent on, whether those projects were over or under budget, or whether those projects were on time.

Q. Where does this leave your conclusion about capital investment in ADMS other than the software?

A. Staff is unable to determine whether the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of investment for the non-software portion of ADMS was prudent or not, which argues for a sizable disallowance of over $20M. Given the uncertainty about a such large portion of the project budget, Staff's disallowance does not include loadings; Staff reserves the right to calculate

31 Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Pages 13 and 14.
32 Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Page 14.
33 Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Page 15.
34 Staff/803, Confidential PGE response to Staff DR 833 Attachment A, Page 16.

loadings once more is known about the project budget. Staff invites PGE to address this concerning issue in the Company's Reply Testimony. It is essential that PGE provides substantive information about what constituted this investment at a project-level (or at an equivalently granular basis), whether those projects/activities were over or under budget, and whether those projects/activities were on time.

Q. Do you have any other concerns about capital investment in ADMS?

A. Yes. Staff notes that at the time of the rate case filing, the estimated final cost that was not yet in service was $27.4M.[35] It is not clear whether the project will be in service by the tariff effective date.

Q. What are your concerns around the in-service date?

A. Staff may be unable to evaluate the prudence of the final costs for projects still under construction while a rate case is pending. Given the timing of testimony and other milestones in this rate case, it may be difficult to determine whether the Company was able to anticipate knowable problems and meet project deadlines. Failure to meet deadlines can, for various reasons, result in cost overruns.

This problem may be particularly significant in this rate case because of COVID-19. That is, there is a question of whether the Company was or will be able to acquire the necessary equipment, labor, and materials in the past year to meet its deadline of April 30, 2022. In the midst of the challenges of a global

[35] Staff/802, PGE response to Staff DR 833.

pandemic, risks to ratepayers should be minimized, and costs should be disallowed in the event that in-service dates are not met.

Q. What are your recommendations regarding these concerns?

A. Staff recommends that any ADMS capital investments not used and useful by April 30, 2022, as demonstrated through an officer attestation, should be removed from rates effective May 1, 2022. The Company would not be precluded from seeking ratemaking treatment in a future general rate case.

Further, for ADMS capital investments for which PGE wants cost recovery in this case, Staff recommends costs be capped at the total cost forecasted for the projects as of the date of the hearing in this case. Any costs for these projects that exceed those forecasts would be eligible for inclusion in a subsequent rate case, subject to a prudence review.

ISSUE 2. ADMS OPERATIONS AND MAINTENANCE (O&M)

Q. What has the Company proposed for ADMS O&M Costs?

A. The rate case includes ADMS O&M of $3.8M,[36] $3.2M of which is forecast labor costs.[37] Approximately $0.5M is for ongoing maintenance costs.[38] The labor costs are for the team PGE is adding to staff ADMS. This team consists of 28 employees: 14 Distribution System Operators, two Grid Tech Engineers, two Grid Tech Analysts, four Distribution Operation Engineers, two Trainers, one Simulator Specialist, one IT administrator, one GIS specialist, and one Distribution Operations Manager.[39]

Q. How did PGE develop the forecast labor costs?

A. In testimony PGE describes performing three different estimating exercises, one based on internal, historical estimates for similar projects, one based on benchmarking of peer utilities, and finally one based on estimates provided by consultants.

Staff submitted discovery to better understand PGE's forecast. Specifically, Staff requested the underlying data for a table in PGE's testimony (Table 6, ADMS O&M) which summarizes ADMS program O&M for 2020 actuals, 2021 budget and 2022 forecast. Staff also requested a narrative description of the justification of the size of the team added to staff ADMS, and of the justification of the composition of titles of the team added to staff

[36] PGE/800, Bekkedahl-Jenkins/31.
[37] PGE/800, Bekkedahl-Jenkins/34.
[38] PGE/800, Bekkedahl-Jenkins/35.
[39] PGE/800, Bekkedahl-Jenkins/34.

ADMS.[40] Finally, Staff requested underlying analysis, data, and research done to justify the size of the team, and the composition of the team.[41]

Q. What did you learn from the Company's response to this discovery?

A. PGE's confidential response to Staff data request 842 consisted of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, and provided substantive information about the Company's analysis in assembling the team to staff ADMS.[42] The **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[43]

PGE assumed a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for all other roles. PGE compared the

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[40] Staff/802, Staff DR 842.
[41] Staff/802, Staff DR 842.
[42] Staff/803, Confidential PGE response to Staff DR 842.
[43] Staff/803, Confidential PGE response to Staff DR 842.
[44] Staff/803, Confidential PGE response to Staff DR 842, page 13.
[45] Staff/803, Confidential PGE response to Staff DR 842, page 13.

proposed staffing levels to other utilities: **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]**[46] Staff found comparisons to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** informative. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was also included, but Staff found this comparison less informative as the data was partially regional and partially system-wide.[47] The Company's proposed staffing was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[48] the other utilities, while having comparable key metrics such as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[49] PGE's $3.2M forecast of O&M labor cost included in the rate case is consistent with the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** respectively.

Q. Did this information enable evaluation of whether the Company's proposed ADMS O&M Costs are prudent?

46 Staff/803, Confidential PGE response to Staff DR 842, page 5.
47 Staff/803, Confidential PGE response to Staff DR 842, page 5.
48 Staff/803, Confidential PGE response to Staff DR 842, page 5.
49 Staff/803, Confidential PGE response to Staff DR 842, page 5.

A. Yes. Given this review Staff does not challenge the prudency of PGE's proposed ADMS O&M costs.

ISSUE 3. DISTRIBUTION PROJECTS

Q. Could you provide a description of the process through which these projects were reviewed?

A. Yes. Transmission and distribution projects were reviewed collaboratively. Ms. Hanhan reviewed projects that were primarily transmission projects (based on FERC account). Ms. Hanhan's testimony is Hanhan/700. I reviewed projects that were primarily distribution projects (based on FERC account). As noted in Ms. Hanhan's testimony there were over 100 projects included in the nearly $1.5 billion at issue in this case.[50] Staff reviewed distribution projects with total loaded costs above $6M, as well as a project involving meter exchanges. Note that for the cost numbers below Staff relied on PGE's response to Staff DR 311:

Distribution System Construction II	$149,324,377
Dist. Customer Line Construction II	$107,247,031
Replace Failed Underground Cables	$47,668,661
Outage or Emergency Replacement	$41,690,051
Construct Marquam Project	$35,359,727
Unjacketed Cable Replacement Prgrm	$33,581,511
Purchase Distribution Transformers	$26,523,272
Brookwood Substation Conversion	$23,612,587
Street and Area Light Construction	$21,846,834
Division Transit Project (DTP)	$20,127,130
Distribution Automation	$20,122,204
PCB Transformer Replacement	$17,826,204
Purchase Customer Meters	$15,252,247
Silverton Capacity Addition	$10,905,981
Willbridge Station 11kV Conversion	$10,596,085
Shute Capacity Addition	$10,006,219
Marquam Radial Feeder Addition	$9,483,577
Replace/Rewind Failed Transformers	$8,902,353

[50] Staff/802, PGE response to Staff DR 311.

Remote Disconnect Project	$8,497,001
Garden Home Substation Upgrade	$7,997,233
Outer Div Multi-Modal Safety Proj	$6,213,950
Sensus DT34 Meter Exchanges	$5,702,996

As discussed in Ms. Hanhan's testimony, Staff structured the project review process based on Commission guidance in Order No. 20-473 which encouraged sampling of projects. As Ms. Hanhan describes, Staff reviewed each project valued above $6M, and sampled projects valued below $6M.[51]

A full list of the projects, including costs and in-service dates, that make up the nearly $1.5 billion in Exhibit PGE/800, Table 1, is included in Exhibit Staff/802.[52]

Q. Which projects will be covered in this testimony?

A. This testimony focuses on the following projects:

Marquam Substation Project	$35,359,727
Division Transit Project (DTP)	$20,127,130
Brookwood Substation Conversion	$23,612,587
Shute Capacity Addition	$10,006,219
Marquam Radial Feeder Addition	$9,483,577
Replace/Rewind Failed Transformers	$8,902,353
Remote Disconnect Project	$8,497,001
Outer Div Multi-Modal Safety Proj	$6,213,950
Sensus DT34 Meter Exchanges	$5,702,996

Q. Do you have overarching concerns about the projects that you wish to discuss?

[51] Staff/Hanhan/700.
[52] Staff/802, PGE response to Staff DR 311.

A. Yes. Staff has identified several projects where the in-service date is still in question.

Q. Which investments are Staff concerned may not be in service by the time rates go into effect?

A. Below is a list of four distribution projects valued greater than $1M that Staff identified as not in service (either in full, or partially) as of the rate case filing.

Project	Value	In-service date(s)
Brookwood Substation Conversion	$23,612,587	December 2021, April 2022[53]
Shute Capacity Addition	$10,006,219	December 2021[54]
Replace/Rewind Failed Transformers	$8,902,352	Monthly,[55] with approximately $3.8M in 2022[56]
Remote Disconnect Project	$8,497,001	Monthly,[57] with approximately $630,000 in 2022[58]

Q. What are the concerns regarding project timelines and in-service dates?

A. Staff's concerns are the same as discussed in my testimony in Issue 1.

Q. Is your recommendation the same?

A. Yes. Staff recommends that any of the distribution projects noted above not used and useful by April 30, 2022, as demonstrated through an officer attestation, should be removed from rates effective May 1, 2022. The Company would not be precluded from seeking ratemaking treatment in a

53 Staff/802, PGE response to Staff DR 311.
54 Staff/802, PGE response to Staff DR 311.
55 Staff/802, PGE response to Staff DR 311.
56 Staff/802, PGE response to AWEC DR 006, Attachment 006-C.
57 Staff/802, PGE response to Staff DR 311.
58 Staff/802, PGE response to AWEC DR 006, Attachment 006-C.

future general rate case. Further, for the distribution projects noted above, Staff recommends costs be capped at the total cost forecasted for the projects as of the date of the hearing in this case. Any costs for these projects that exceed those forecasts would be eligible for inclusion in a subsequent rate case, subject to a prudence review

Q. Please briefly describe how you structured your project-by-project review.

A. As noted previously in my testimony, transmission and distribution projects were reviewed collaboratively. Ms. Hanhan and I coordinated processes for reviewing these projects. Ms. Hanhan's testimony describes Staff's review of project justification forms, and the difficulties encountered in doing so.[59]

Q. Do the general cost tracking concerns Ms. Hanhan notes for transmission projects also apply to distribution projects?

A. Yes. Ms. Hanhan's testimony articulates Staff's concerns with project justification forms as documents of record for project review, and how these forms do not provide sufficient information to determine how costs were managed, as well as broader concerns about cost tracking and cost control.[60] These concerns are applicable to both transmission and distribution projects. Staff issued discovery where cost increases were unclear to try to learn more about whether they were justified, or whether Staff should recommend

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[59] Staff/Hanhan/700.
[60] Staff/Hanhan/700.

disallowance, or both. The remainder of this section of testimony will address adjustments for specific projects.

Q. Please describe your review of the Marquam Substation Project ($35,359,727).

A. I collaborated with Staff's safety and rates divisions to analyze PGE's investment. Staff reviewed a white paper pertaining to the Marquam Substation Project, **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]**[61] along with project justification forms, and discovery related to the project.

Q. Do you have any concerns with this project?

A. Yes. Staff has concerns with cost or cost management. There are ambiguous budget increases throughout the project justification form for this project. In general, the information presented to Staff was not clear or intuitive. For example, the non-loaded cost of this project as listed in the PJF appeared to be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** It is unclear whether this is because part of the project was already placed into service, or whether this is an error in cost tracking, or whether PGE is only opting to put part of the project into rate base. The following are several particularly problematic increases: **[BEGIN CONFIDENTIAL]**

61 Staff/803, Confidential PGE Supplemental Response to Staff DR 334, Confidential Attachment 334-A, Marquam Substation Deferral Risk Mitigation.

- [redacted][62]
- [redacted][63]
- [redacted][64]
- [redacted][65]
- [redacted][66] **[END CONFIDENTIAL]**

Based on the ambiguous information provided, it was not possible to determine whether these issues were due to mismanagement. The project justification form does not provide sufficient context of, nor clarity into, cost increases and decreases, and what project changes they map to.

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[62] Staff/803, Confidential PGE Revised Response to Staff DR 198, PJF 35679.
[63] Staff/803, Confidential PGE Revised Response to Staff DR 198, PJF 35679.
[64] Staff/803, Confidential PGE Revised Response to Staff DR 198, PJF 35679.
[65] Staff/803, Confidential PGE Revised Response to Staff DR 198, PJF 35679.
[66] Staff/803, Confidential PGE Revised Response to Staff DR 198, PJF 35679.

Q. What is your recommended adjustment?

A. Due to the ambiguity of the project justification form Staff cannot verify prudent management of costs. As a result, Staff's recommendation is to disallow the cost increases identified, which, in total, amounts to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in direct costs. Based on the loadings ratio Staff calculated from the project justification form, DR 326, and DR 311, this amounts to a total disallowance of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Staff invites PGE to address and clarify these ambiguities in the Company's reply testimony.

Q. Please describe your review of the Division Transit Project ($20,127,130).

A. I analyzed PGE's investment by reviewing the project justification form and discovery related to the project.

Q. Do you have any concerns with this project?

A. Yes. I have concerns with cost or cost management. In general, the information presented to Staff through in the project justification form was not clear or intuitive. The specific concern with this project is an approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** discrepancy between the "total project capital cost" reported in the project justification form of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** [67] which staff understands to be the most recent total, and the total for capital

[67] Staff/803, Confidential PGE Revised Response to Staff DR 198, PJF 36861.

costs (comprised of Outside Services and Materials) of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[68] reported by PGE in response to discovery asking for itemized projects costs.

The project justification form refers to some amount of construction in aid of construction, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**,[69] which might account for some of this difference. However, the amount reported in the justification form does not match the total reported in itemized project costs of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[70] Whether the noted discrepancy can be explained by construction in aid of construction, or by some other reason, the lack of clarity in the project justification form prevents Staff from accounting for the discrepancy.

Q. What is your recommended adjustment?

A. Due to the ambiguity of the project justification form Staff cannot account for, or evaluate the noted discrepancy, and so cannot verify prudent management of costs. As a result, Staff's recommendation is to disallow the discrepancy identified, which amounts to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in direct costs. Based on the loadings ratio Staff calculated from the project justification form and DR 311, this amounts to a total disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff invites PGE to address and clarify this lack of information in the Company's reply testimony.

68 Staff/802, PGE response to Staff DR 326, Attachment 326-A.
69 Staff/803, Confidential PGE Revised Response to Staff DR 198, PJF 36861.
70 Staff/802, PGE response to Staff DR 326, Attachment 326-A.

Q. Please describe your review of the Marquam Radial Feeder Addition project ($9,483,577).

A. I collaborated with members of Staff's safety and rates divisions to analyze PGE's investment. Staff reviewed a white paper pertaining to the Marquam Substation Project, which also discusses the Radial Feeder Addition, **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]**[71] along with project justification forms, and discovery related to the project.

Q. Do you have any concerns with this project?

A. Yes. As with prior projects Staff has concerns with cost or cost management. There are ambiguous budget changes throughout the project justification form for this project. In general, the information presented to Staff was not clear or intuitive. The specific concern with this project is the difference between the "total capital" cost reported in the project justification form of **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]**[72] which staff understands to be the most recent total, and the amount being requested in the rate case, approximately $9.5M.

The difference is roughly **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Staff understands the difference between a project's capital costs and a project's fully loaded

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71 Staff/803, Confidential PGE Supplemental Response to Staff DR 334, Attachment 334-A, Marquam Substation Deferral Risk Mitigation.

72 Staff/803, Confidential PGE Revised Response to Staff DR 198, PJF 36571.

costs to typically be 30%, and thus would expect a difference of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. What is your recommended adjustment?

A. Due to the ambiguity of the project justification form Staff cannot account for or evaluate the difference between expected fully loaded project costs and the amount request in the rate case, and so cannot verify prudent management of costs. As a result, Staff's recommendation is to disallow the difference identified, which, in total, amounts to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in direct costs. Based on the loadings ratio Staff calculated from the project justification form and DR 311, this amounts to a total disallowance of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Staff invites PGE to address and clarify this difference in the Company's reply testimony.

Q. Please describe your review of the Outer Division Multi-Modal Safety Project ($6,213,950).

A. I analyzed PGE's investment by reviewing the project justification form and discovery related to the project.

Q. Do you have any concerns with this project?

A. Yes, as with prior projects Staff has concerns with cost or cost management. This project justification form included information about budget changes that, compared to most other forms Staff reviewed, was less ambiguous and clearer. However, the specific concern with this project is also the difference between the "total capital" cost reported in the project justification form of **[BEGIN**

CONFIDENTIAL] [redacted], **[END CONFIDENTIAL]**[73] which Staff understands to be the most recent total, and the amount being requested in the rate case, approximately $6.2M.

The difference is roughly **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Staff understands the difference between a project's capital costs and a project's fully loaded costs to typically be 30%, and thus would expect a difference of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. What is your recommended adjustment?

A. Due to the ambiguity of the project justification form Staff cannot account for, or evaluate the difference between, expected fully loaded project costs and the amount request in the rate case, and so cannot verify prudent management of costs. As a result, Staff's recommendation is to disallow the difference identified, which, in total, amounts to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in direct costs. Based on the loadings ratio Staff calculated from the project justification form and DR 311, this amounts to a total disallowance of **[BEGIN CONFIDENTIAL]** [redacted]. **[END CONFIDENTIAL]** Staff invites PGE to address and clarify this difference in the Company's reply testimony.

Q. Please describe your review of the Sensus DT34 Meter Exchanges project ($5,702,996).

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[73] Staff/803, Confidential PGE Revised Response to Staff DR 198, PJF 36910.

A. I analyzed PGE's investment by reviewing the project justification form and discovery related to the project.

Q. Do you have any concerns with this project?

A. Yes. PGE exchanged approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL**[74] Sensus Device Type 34 meters (DT34) due to **[BEGIN CONFIDENTIAL]** '[redacted]." **[END CONFIDENTIAL]**[75] PGE and Sensus reached a Settlement Agreement to address "the insufficient data received from a specific meter model and the plan for Sensus to correct the issue by providing deeply discounted new meters."[76] Meters replaced in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[77] carried a price of **[BEGIN CONFIDENTIAL]** [redacted], **[END CONFIDENTIAL]**[78] and PGE made purchases at this price.[79] The $5.7M sought in recovery includes a capital investment of approximately $3.5M.[80] In response to discovery PGE noted the Company's investment in the DT34 meters will not be fully depreciated prior to replacement, and PGE will write-off any undepreciated investment.[81]

Q. Do you have a recommendation?

A. No. Staff is satisfied to see the Company is not seeking depreciation expense, or return, on the DT34 meters.

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74 Staff/803, Confidential PGE response to AWEC DR 006, PJF 36470.
75 Staff/803, Confidential PGE response to AWEC DR 006, PJF 36470.
76 Staff/802, PGE response to Staff DR 758.
77 Staff/803, Confidential PGE response to AWEC DR 006, PJF 36470.
78 Staff/803, Confidential PGE response to AWEC DR 006, PJF 36470.
79 Staff/802, PGE response to Staff DR 759.
80 Staff/802, PGE response to Staff DR 761.
81 Staff/802, PGE response to Staff DR 757.

Q. Did you review additional projects?

A. Yes. I reviewed 8 so-called "blanket projects" which are listed below. I analyzed PGE's investments by reviewing the project justification forms and discovery related to the projects.

Distribution System Construction II	$149,324,377
Dist. Customer Line Construction II	$107,247,031
Replace Failed Underground Cables	$47,668,661
Outage or Emergency Replacement	$41,690,051
Unjacketed Cable Replacement Prgrm	$33,581,511
Purchase Distribution Transformers	$26,523,272
Street and Area Light Construction	$21,846,834
Purchase Customer Meters	$15,252,247

Q. What did you learn reviewing these projects?

A. Broadly speaking these projects involve ongoing activities without conventional project phases, or conventional launch and completion dates. They involve for example activities such as routine distribution system construction, purchase of distribution transformers and customer meters, and distribution system repair. While the activities in question may be customary, in aggregate the size of the investment can be quite large.

Unfortunately, Staff's concerns with the project justification forms lacking sufficient information to determine how costs were managed were only magnified by the ongoing nature of these projects.

Q. Do you have a recommendation at this time?

A. Yes. Staff invites PGE, in its Reply Testimony, to clarify how cost control process and protocols, accountability mechanisms, and the Company process to plan, maintain, and meet its budget targets, all apply, or don't apply, to these blanket projects. Given the size of these investments there is great need to reassure the Commission, Staff, CUB, AWEC, and other stakeholders of a high internal standard for cost tracking.

Staff is still reviewing the projects and reserves the right to provide additional adjustments in Reply Testimony.

Q. Will Staff review testimony from other parties on these issues?

A. Yes. Staff will review and evaluate testimony from other parties and offer reply testimony on these in future rounds.

Q. Have you prepared a table showing all adjustments in your Staff Exhibit/800 testimony addressing all issues you have written about herein?

A. Yes. **[BEGIN CONFIDENTIAL]**

[redacted]		[redacted]	
[redacted]		[redacted]	
[redacted]		[redacted]	
[redacted]		[redacted]	
[redacted]		[redacted]	

[END CONFIDENTIAL]

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: NICK SAYEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statements

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	Nick Sayen
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Public Affairs, Environmental Public Policy, University of Wisconsin-Madison, 2007 Bachelor of Arts in Communication Studies, University of Montana, 2002
EXPERIENCE:	For two years I have been employed at the Public Utility Commission of Oregon where I have provided analysis and comments on integrated resource plans, renewable natural gas cost-effectiveness, and various dockets involving energy efficiency and demand response. I also staffed UM 2005, the investigation into electric utility distribution system planning. I also have over ten years of experience in the energy efficiency field. This included implementation of utility efficiency programs for commercial buildings, evaluation of residential efficiency programs, project management, and policy research and analysis.

CASE: UE 394
WITNESS: NICK SAYEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Exhibits in Support
Of Opening Testimony

October 25, 2021

ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: March 21, 2019

REGULAR __X__ **CONSENT** ____ **EFFECTIVE DATE** __**Upon Approval**__

DATE: March 13, 2019

TO: Public Utility Commission

FROM: Caroline Moore CM

THROUGH: Jason Eisdorfer and JP Batmale JE JP

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF: (Docket No. UM 2005) Request to open an investigation into distribution system planning.

STAFF RECOMMENDATION:

Staff recommends that the Oregon Public Utility Commission (OPUC or Commission) open an investigation into distribution system planning (DSP). The investigation would develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments.

DISCUSSION:

Issue

Whether the Commission should open an investigation into electric distribution system planning.

Applicable Law

Under ORS 756.515(1), whenever the Commission believes that an investigation of any matter relating to any public utility or telecommunications utility or other person should be made, the Commission may, on its own motion, investigate any such matter.

Analysis

Background

For decades, Oregon utilities have engaged in a robust bulk system planning process known as Integrated Resource Planning (IRP).[1] With the introduction of Smart Grid Report requirements in 2012, the Commission began to broaden the existing planning paradigm to include a more thoughtful consideration of grid modernization measures and increased attention to the distribution system. Through IRP Order Nos. 17-386 and 18-138, the Commission furthered this evolution of the utility planning framework by directing Portland General Electric and Pacific Power to work with Staff and parties to define a proposal for opening an investigation into distribution system planning.[2]

On February 19, 2019, Staff released its whitepaper, "A Proposal for Electric Distribution System Planning." In this paper Staff outlined the rationale for opening an investigation into distribution system planning. (See Attachment A.) Staff's whitepaper included the key drivers for investigating DSP, the desired outcomes of both the investigation and the future planning process, a near-term scope and schedule for the investigation, and a comprehensive list of additional planning considerations.

Staff held a stakeholder workshop to review the whitepaper and receive feedback on the proposed investigation prior to requesting that the Commission open the investigation. Staff appreciates the questions and insights provided by participants. More than 40 attendees participated in the March 1, 2019 workshop, including representatives from:

- Alliance of Western Energy Consumers
- Economist.com
- Energy Trust of Oregon
- ICF
- Idaho Power Company
- Northwest Energy Coalition
- Northwest Natural
- Oregon Citizens Utility Board
- Oregon Department of Energy
- Oregon Solar Energy Industry Association
- PacifiCorp
- Portland General Electric
- Renewable Energy Coalition
- Renewable Northwest
- TriMet

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[1] Staff uses the term bulk system to generally refer to the infrastructure used to balance utilities' system-wide resources and loads, including centralized generation resources and the transmission system that delivers the output from those resources to the utilities' local distribution networks. Staff expects more precise definitions of bulk and distribution systems to emerge through the DSP investigation.

[2] *In re Portland General Electric*, OPUC Docket No. LC 66, Order No. 17-386 at 19 (Oct. 9, 2017); *In re PacifiCorp*, OPUC Docket No. LC 67, Order No. 18-138 at 22 (Apr. 27, 2018).

Participants asked questions about Staff's proposed investigation and identified important considerations for further exploration in the investigation, including:

- What is the purpose of the distribution system plan and who is the audience?
- If the desired outcome of DSP is maximizing customer value through distribution-level investments and operations, how will customer value be defined?
- What is the outcome of the plan, in terms of acknowledgement, approval acceptance, or other processes? And, what precisely will be acknowledged, approved, or accepted?
- What are the appropriate components of the distribution system plans, including the timescale and level of detail?
- What information, analyses, and data do stakeholders need to see? What information may not provide value to Oregon stakeholders or require more resources to produce than the value it brings to the DSP process?
- How will DSP be linked to other regulatory processes, such as IRPs and Smart Grid Reports?

Participants also engaged in a small-group, brainstorm exercise to develop topics for education-focused workshops. A summary of ideas shared during the group exercise is provided in Attachment B.

Based on the workshop discussion, Staff plans to move forward with the investigation proposed in the Staff whitepaper with a single modification described below. The high level of engagement and meaningful insights notwithstanding, the workshop reinforced that tackling the breadth of technical, financial, policy, and planning issues within the scope of DSP may be challenging. Staff finds that the best course of action is to begin the process without further delay—understanding that there is much to learn and parties should remain adaptive and open to iteration throughout the investigation.

Proposed Investigation Structure and Timeline
Staff proposes an investigation structure that is phased, adaptive, and involves considerable stakeholder engagement. The proposed structure is summarized in the following table, which is based on Figure 6 of Staff's whitepaper. The investigation structure contains a modification to the Phase 3 key objective, which highlights the need for further discussion about the appropriate Commission action after the initial distribution system plans are accepted.

	Pre-Launch	Phase 1: Baselining	Phase 2: Assessment	Phase 3: Refinement
Time-frame	February - March 2019	March 2019 – December 2019	January 2020 – May 2021	June 2021 - ongoing
Goal	Identify the focus of and process for a DSP investigation	• Begin developing a knowledge-base for the major DSP principles • Develop guidelines to evolve the smart-grid report into a robust (initial) distribution system plan	Review the current state of each utility's system, identify near- and long-term needs and next steps to get to optimization	Refine planning process, incorporate additional considerations and requirements
Process	• Staff whitepaper released: Outlines Staff proposal for DSP investigation. • Scoping workshop: Stakeholder feedback on Staff proposal i.e., establish whether OPUC has outlined the correct drivers, outcomes, phases, goals and deliverables. • Public meeting memo: Staff's final proposal requesting investigation.	• Workshops: Staff will conduct a series of workshops to establish a baseline understanding of distribution system planning fundamentals, current utility processes, and outstanding distribution planning needs. • Draft guidance: Staff releases draft proposal for DSP guidance. • Stakeholder comments/ workshop(s) as necessary • Revised draft guidance • Final comments • Public meeting memo: Staff final proposal for DSP guidance.	• Establish individual utility dockets • Utilities file based on Commission guidance (~ 8 months) • OPUC and stakeholder engagement process (~ 6 months) ▪ Comments ▪ Workshops • Public meeting memo: Staff final recommendations (~April 2021)	• Continue to implement planning process as directed by Commission • Improve and evolve content, process, tools, and methodologies • Continue to incorporate evolving policy and operational requirements
Key Objective	Commission order opening investigation	Commission order adopting guidance for utilities to file initial DSPs	Commission orders accepting utilities' initial DSPs and direction to refine DSP process and/or DSP guidance	Commission approval of subsequent utility DSPs as determined during Phase 1 and guidance for refinement of subsequent utility DSPs

Following a Commission decision to open the investigation, Staff will develop, share, and begin executing a Phase 1 workshop plan. As the investigation progresses, phases, goals, milestones, and objectives will be shaped by shared learnings and continued stakeholder input. Staff will continue to work to engage a broad stakeholder group throughout the investigation.

Conclusion

After consulting stakeholders, Staff finds that it is necessary to begin taking steps to establish a transparent, robust, and holistic regulatory process for distribution system planning. Staff proposes to launch a phased investigation into DSP that results in maximized customer value through optimized distribution system operations and investments.

PROPOSED COMMISSION MOTION:

Staff recommends that the Commission open an investigation into distribution system planning.

Investigation into distribution system planning

Staff Whitepaper: A Proposal for Electric Distribution System Planning

Introduction

Expectations for Oregon's electrical grids are changing. Technological advancements in grid infrastructure and distributed energy resources, combined with declining costs, evolving policies, and changing consumer interests are driving greater consideration for investments on the distribution system. These distribution-level investments create opportunities for Oregon's investor-owned utilities to optimize system operations and maximize value for customers. Currently, the Oregon Public Utility Commission (OPUC or Commission) and stakeholders lack the visibility and planning structure to ensure utilities are best positioned to capture these benefits.

The purpose of this white paper is to outline OPUC Staff's (Staff) proposal to develop a holistic, robust planning structure through an investigation into distribution system planning (DSP). Staff's proposal includes:

1) Proposed drivers, outcomes, and considerations for the investigation; and
2) A draft scope for the investigation.

Staff's proposal is intended to serve as the starting point of an inclusive public process. In its proposal, Staff outlines some of the central drivers and outcomes identified for the investigation. However, Staff recognizes that there is a wide range of significant, interconnected DSP elements for which the appropriate place in the investigation framework will become clearer through continued discussion with utilities and stakeholders. Staff's proposal outlines a number of these considerations, in addition to the stated drivers and outcomes.

Following the release of this whitepaper, Staff will hold a workshop with utilities and other interested parties to receive feedback on the proposed drivers, outcomes, considerations, and scope. Staff will incorporate this feedback into a request to the Commission to open a new investigation into DSP. Working with stakeholders, Staff expects to continue to explore and refine the elements of the investigation presented in this whitepaper.

Key Terms

For the purposes of this whitepaper, Staff adopts the following definitions from the U.S. Department of Energy (USDOE), but recognizes that additional refinement will occur in the proposed investigation.

Distribution system: *The portion of the electric system that is composed of medium voltage (69 kV to 4 kV) sub-transmission lines, substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system.*

Distributed Energy Resource: *Distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid.*

Source: See page 7 of Modern Distribution Grid: Volume I https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

Background

Smart-Grid Reports: A foundation for modern distribution-level investments

In 2012, the Commission identified a need for utilities to consider and invest in smart-grid technologies, and to report on these activities through an annual Smart-Grid Report.[1] The Commission concluded that adopting a reporting requirement, rather than a planning requirement, was appropriate since the technologies were in different stages of development and affordability.

Since 2013, Oregon's investor-owned electric utilities, Idaho Power Company (IPC), PacifiCorp (PAC), and Portland General Electric (PGE) have filed annual or biennial Smart-Grid Reports. Reports are required to include utility strategy, goals, and objectives for smart grid investments, as well as the status of and plans for investments over the next five years within the Commission guidelines.

Staff greatly appreciates the thought and effort demonstrated by the utilities in developing the Smart Grid Reports, which provide important insight into a wide range of innovative grid modernization projects. However, Staff will illustrate the need to further expand and evolve this reporting framework in subsequent sections of the whitepaper.

Commission Guidance: Expanding utility transparency and regulatory process

In 2016 and 2017 respectively, Staff identified the need for additional planning processes specific to distribution-level investment in its comments on PGE's and PAC's Integrated Resource Plans (IRPs).[2] The following excerpt from Staff's initial comments in PGE's LC 66 2016 IRP captures Staff's motivation for initiating a DSP process:

"The description of PGE's thorough DSP's activities in the IRP update is helpful, but is not focused on getting to Staff's main issue of the need for improved transparency and creation of an overall plan for distribution system investments. PGE's four priority elements may be the best four areas for focus from a ratepayer perspective but the reasoning behind these selections and the ultimate goal these activities are intended to achieve was not provided, so Staff and stakeholders are unable to provide review of PGE's roadmap and plan."

Recognizing the need for a more robust distribution-level planning framework, the Commission directed both electric utilities to work with Staff and parties to define a proposal for opening a DSP investigation as a condition of IRP acknowledgement.[3]

[1] See Commission Order No.12-158 for Commission guidelines, policy goals, objectives, and reporting requirements related to smart-grid activities. https://apps.puc.state.or.us/orders/2012ords/12-158.pdf.
[2] See Dockets LC 66 and LC 67.
[3] See Order No. 17-386, p. 19 (PGE) and Order No. 18-138, p. 22 (PAC).

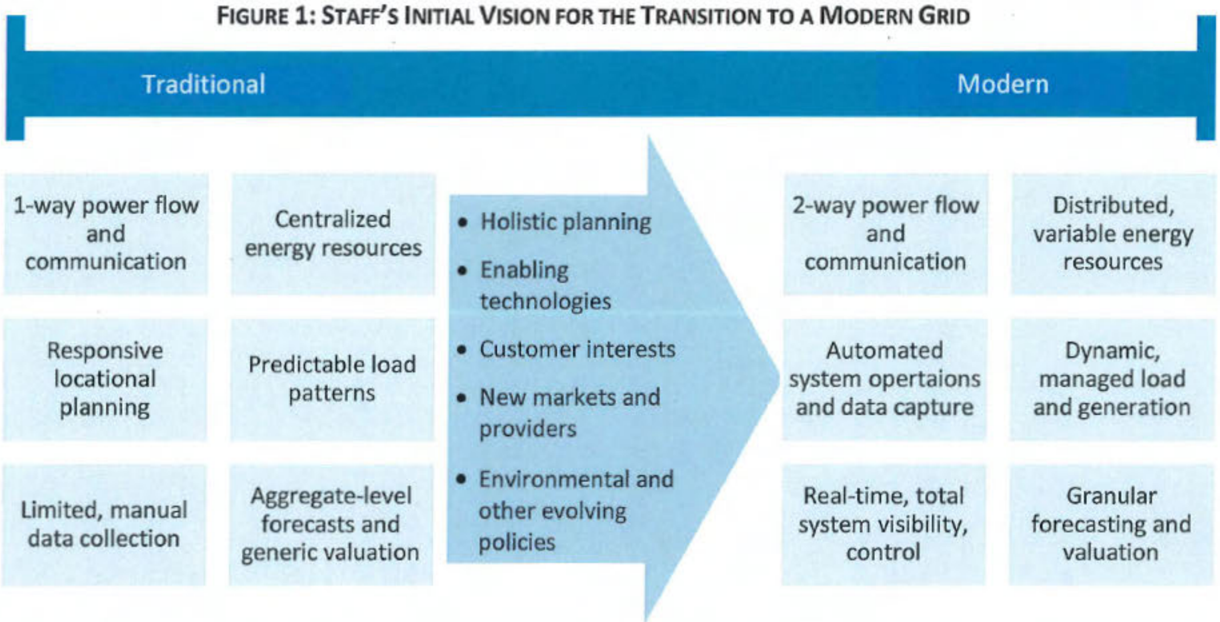
Governor's Climate Agenda: Prioritizing a modern, affordable grid

On November 28, 2018, Governor Kate Brown released the Oregon Climate Agenda, an eight-point strategy to achieve the state's climate goals over the next five years.[4] Key among these priorities, and likely to impact the electric grid and distribution system planning, are:

- Decarbonizing the electric sector by "encouraging grid modernization while maintaining affordable and competitive electricity rates";
- "[E]xpanding electric vehicle infrastructure and incentives to support 50,000 electric vehicles on Oregon roads by 2020";
- "[E]xpand[ing] the reach of energy efficiency programs"; and
- Expanding opportunities for customers to, "access clean energy services from their utilities while ensuring utility regulation supports the utility system and does not preference new customers over existing ones."

Staff envisions DSP as a critical step in moving the state's expectations for a modern gird forward. While a more precise long-term vision for the modern grid will develop through the implementation of DSP, Staff foresees an eventual transition to a more responsive platform that is capable of minimizing the frequency and impact of outages (e.g., automated outage restoration), supporting decarbonization (e.g., better integrating renewables), optimizing system performance (e.g., volt-var management), and enabling customers to deploy DERs in a manner that minimizes their costs while maximizing system benefits (e.g., more accessible hosting capacity data, advanced price signals.)[5]

FIGURE 1: STAFF'S INITIAL VISION FOR THE TRANSITION TO A MODERN GRID



Note: The DSP investigation will provide a clearer understanding of where each utility falls within this continuum.

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[4] State of Oregon Office of the Governor. *Oregon Climate Agenda: A Strong, Innovative, Inclusive Economy While Achieving State Climate Emissions Goals. 2018. https://www.oregon.gov/gov/policy/Documents/Governor Kate Brown Climate Agenda.pdf.*

[5] Staff is referring to responsive pricing that signals conditions such as time, season, location/proximity to load, and other system conditions.

This whitepaper serves as an initial step in fulfilling the Commission's direction to open an investigation into DSP. The remainder of this report will outline Staff's initial proposal for initiating the DSP investigation, including the drivers, outcomes, considerations, and scope.

Proposed Investigation

FIGURE 2: STAFF'S PROPOSED FRAMEWORK FOR A DSP INVESTIGATION

States across the nation are engaging in a regulatory investigation into distribution system planning. Each DSP effort is shaped by that state's unique motivations and conditions.[6] Therefore, clearly defining Oregon's "drivers" for an investigation into DSP is the foundation of Staff's proposal. Once the drivers are established, expected outcomes to address the drivers can be identified, and a roadmap to achieve those outcomes can be constructed, i.e., the investigation scope.

The following sections will review the components of Staff's DSP investigation. Staff will also list the many additional elements for which the appropriate place in this framework will become clearer as OPUC works with utilities and stakeholders throughout this investigation. Staff will refer to these elements as considerations.

Drivers

Staff finds that the utilities are providing safe, reliable, affordable service and no known system crises are driving the need to create new DSP processes (e.g., current DER adoption levels are not immediately threatening reliability). Creating a framework to help parties understand and engage in DSP now will allow OPUC, the utilities, and stakeholders the opportunity to anticipate the impacts of the evolving distribution landscape and determine the best mechanisms to address those impacts moving forward. Within this context, Staff has identified two *proactive* drivers for initiating Oregon's DSP investigation.

1. Insight (procedural driver): The near-term need to establish visibility and holistic engagement in utilities' distribution-level investments.[7]
2. Optimization (operational driver): The longer-term need to ensure the operation of the changing distribution system maximizes efficiency and customer value.

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[6] The Pacific Northwest National Laboratory and Lawrence Berkeley National Laboratory's report, *Distribution System Planning – State Examples by Topic*, published in 2018, provides a useful overview of other state's' drivers, outcomes, and scope. https://epe.pnnl.gov/pdfs/DSP_State_Examples-PNNL-27366.pdf.

[7] Staff considers the need to establish more insight an opportunity for near-term action, but does not suggest that insight is only needed in the near-term. Staff proposes that insight is needed on an ongoing basis.

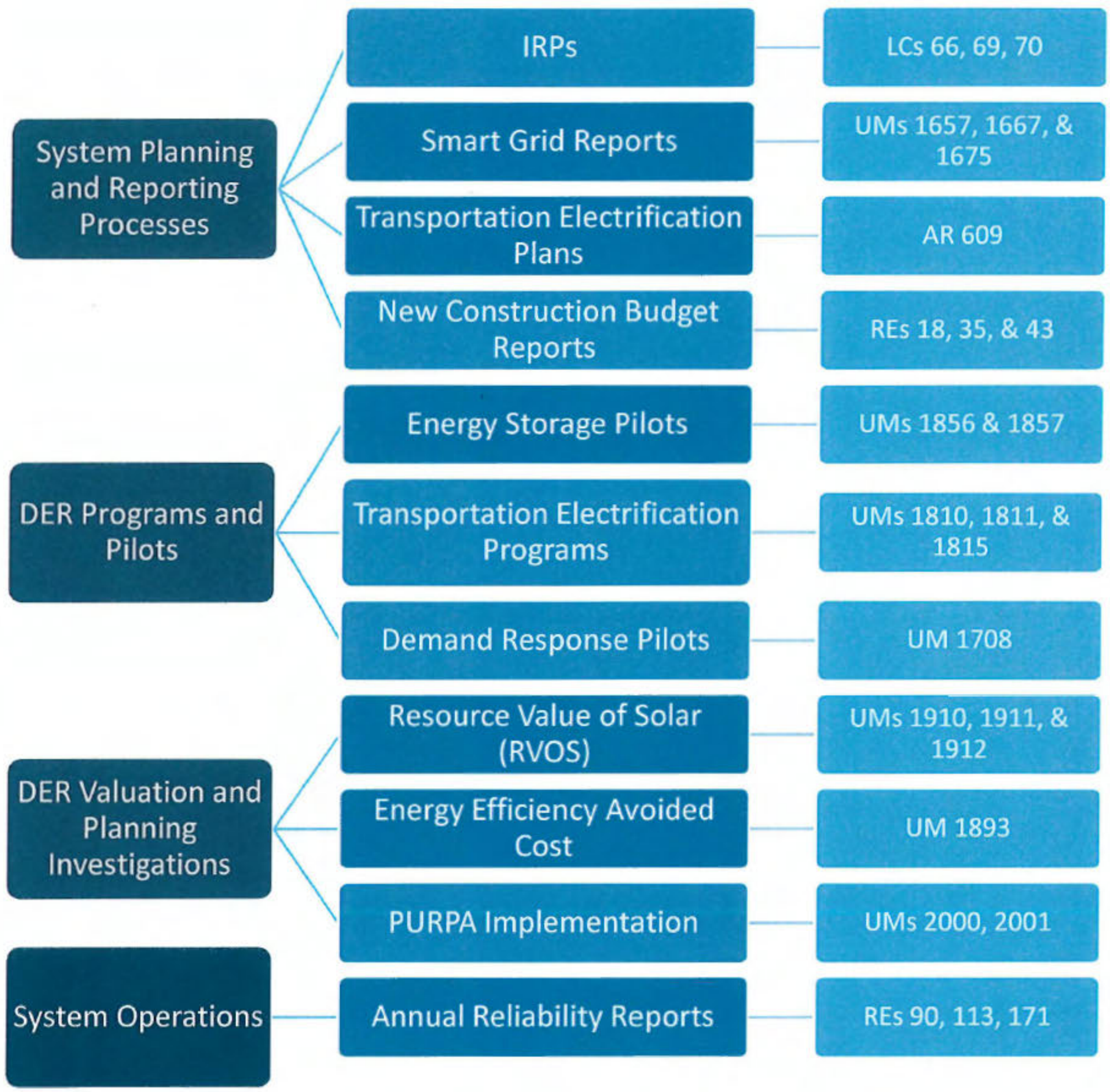
Insight

While OPUC and stakeholders are engaged with utilities to ensure the safety and reliability of the distribution system, there is less rigorous engagement in the utilities' distribution system planning processes and ongoing investment decisions. This is driven by several factors, including:

- **Limited visibility:** Unlike bulk system planning such as IRPs and transmission planning, the majority of utility distribution system planning and investment decisions occur through internal processes driven by short-term needs to maintain system reliability. OPUC and stakeholder visibility into these investments generally occurs at the aggregate level through rate cases or the utilities' New Construction Reports, which only report on individual investments over $10 million.[8]
- **Limited engagement:** OPUC and stakeholders also lack opportunities to participate actively in distribution planning processes and review proposed investments before they occur. When visibility is provided, it is primarily a one-directional flow of information, after the utility decision making process is complete (e.g. rate cases and Smart Grid Reports). A transparent utility planning process will provide OPUC and stakeholders with the opportunity to meaningfully engage with utilities' planning and decision-making processes, understanding the "how", "why", and priorities in addition to the "what".
- **Siloed actions:** Staff finds that there are a variety of disparate planning processes, reports, policies, programs, pilots, and other investigations related to distribution system operations (see Figure 3). OPUC and stakeholders are provided varying levels of insight through individual proceedings, but lack the regulatory connectivity to address distribution-level planning, investments, and operations holistically. A cohesive planning process will provide this whole system view, as well as, much needed procedural efficiency across participants in OPUC's regulatory processes. It will also provide OPUC with a richer understanding of the interaction of distribution-level issues with bulk system planning and ratemaking processes. Staff anticipates additional matters related to cyber security, data management, and third-party engagement in service delivery will further intensify this driver.
- **Nascence:** As demonstrated through Smart Grid Reports, utilities continue to expand their grid modernization learnings and identify opportunities to improve the grid to benefit customers. However, Staff and stakeholders are limited in their exposure to these learnings. Barriers to inclusive stakeholder engagement are heightened by the highly technical aspects of advanced technologies and distribution system operations. A robust planning process, and the associated utility transparency, will promote inclusivity and raise the knowledge-level across parties.

[8] OAR 860-027-0015 requires Oregon utilities with gross operating revenues of $50,000 or more per year to report information on new construction, extension, and new additions to property of the utility to the Commission annually. The report form only requires electric utilities to individually report the three highest cost projects and all projects greater than $10 million.

FIGURE 3: DISTRIBUTION-RELATED OPUC PROCEEDINGS



Optimization

The traditional distribution system was designed to support one-way flow of power from centralized production facilities, across the bulk transmission system and down to the distribution system for delivery to end users, without the breadth of modern communications, controls, and sensing technology available today. The planning and decision-making processes in place today were designed to ensure least-cost, least-risk operation of the traditional system. However, the evolution of technology, policies, markets, and consumer interests are challenging this long-standing paradigm. Staff finds that new processes and tools are required to ensure that 1) the optimal investments, programs, and policies are implemented; and 2) these investments, programs, and policies are implemented such that they maximize reliability, efficiency, and customer value as the landscape continues to evolve.

For example, traditional resource planning practices focus on identifying the aggregate load-resource balance and system-wide resource solutions to meet deficiencies. In the evolving landscape, consideration must be made with more awareness of granular balance of loads and resources and the full range of opportunities to meet the system's needs such as:

- What is the load forecast for a given area?
- What is the generating DER forecast in the area?
- What is the capacity of the distribution system to support the forecasted load-resource balance in that area?
- What other grid services are needed and/or anticipated in that area?
- What is the full range of technological, operational, and customer-driven options to meet those needs?
- How are the outcomes integrated with bulk-system planning and ratemaking processes?

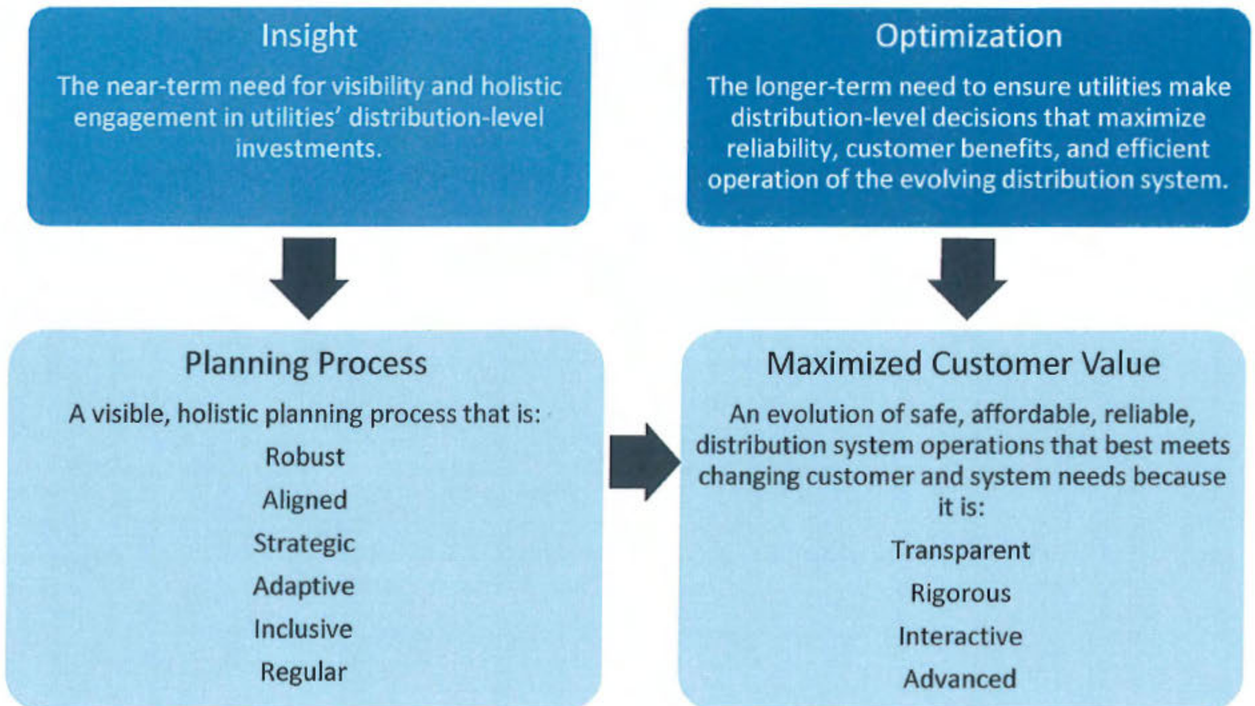
Staff finds that regulatory guidance for a utility DSP planning structure is necessary to support appropriate adoption of DER and grid technologies, and to ensure that utilities make distribution-level decisions that maximize reliability and customer benefits, and maintain efficient operation of the evolving distribution system.

Outcomes

Based on the need to establish insight and optimization, Staff envisions two key outcomes of the DSP investigation:

1. A planning process (procedural outcome): The direct outcome of the DSP investigation will be the creation of a new process that provides sufficient distribution system planning insight. Staff's vision for this process is described further in this section.
2. Maximized customer value (operational outcome): Staff aims to design a DSP process that ultimately results in investment and operational decisions that maximize value for utility customers. Staff's vision for a DSP process that achieves maximized customer value is described further in this section.

FIGURE 4: STAFF'S PROPOSED INVESTIGATION FRAMEWORK



Planning Process

Staff's immediate vision for the DSP investigation is relatively simple: Establish a regulatory planning process that provides adequate distribution system insight. Rather than drive DSP from the top down with prescriptive requirements for distribution-level investments and grid-modernization actions, Staff intends to build a planning structure through which the appropriate utility roadmap will emerge. At minimum, Staff proposes the planning process should be:

- **Robust:** Based on multi-scenario planning principles; considers the full range of technologies and resource types; recognizes the importance of future-proofing; attuned to the state's evolving policy goals e.g., decarbonization, reducing energy burden, resiliency, enhancing customer opportunities.

- **Aligned:** Streamlines the various distribution-related processes, policies, reports, and investigations (see Figure 3.); houses future distribution-related matters; integrates with IRPs such that all system adequacy and investment decisions are coordinated; aligns the procedural timeline and planning horizon with other processes, such as capital budget cycles and IRPs.

- **Strategic:** Provides a strategic roadmap of near and long-term investments that is prioritized and iterative; serves as a space to identify potential issues that will be addressed in separate filings; includes a long-term planning period and a short-term action plan.[9]

[9] Staff understands that the scale and nature of distribution system investments may require shorter planning horizons, action plans, and interim updates.

- **Adaptive:** Recognizes differences across utilities; balances well-defined Commission guidance with the flexibility for utilities to take ownership of the planning process and to adapt to a continually evolving landscape.
- **Inclusive:** Incorporates meaningful OPUC and stakeholder engagement; continues to focus on accessibility across customers and communities; serves as a public resource that is regularly referred to by Staff, stakeholders, and the Commission when considering new investments and how current and proposed projects fit in with the utility's vision.
- **Regular:** Plans are filed with predictability either through a regular schedule or triggered by specifically defined events.

Maximized Customer Value

Staff's ultimate vision for DSP is to maximize customer value by ensuring that the utilities' approach to managing and operating the distribution system is evolving in a least-cost, least-risk manner. While clearer policy objectives are expected to arise through the planning process, Staff's high level expectation is to develop a regulatory DSP structure that enables utilities to better identify system needs and evaluate the evolving range of opportunities that can meet those needs. The intended outcome is an approach to utility distribution system operations that evolves safe, affordable, and reliable, to also include:

- **Transparent:** Provides widespread system visibility; creates a roadmap for optimized locational planning e.g., hosting capacity analysis.
- **Rigorous:** Utilizes advanced methodologies to evaluate and deploy new grid capabilities, DER, and other non-wires alternatives to meet system needs e.g., refined avoided cost methodologies and use cases, multi-scenario analysis, more granular, responsive forecasts and valuation, data analytics enabled by grid modernization.
- **Interactive:** Enables the efficient integration of customer options; responsive to customer interest, environmental and other policy drivers e.g., sends advanced price signals to customers and other DER operators; streamlines interconnection; enables more two-way data and power flows.
- **Advanced:** Deploys modern software, hardware, DER technologies, and capabilities that maximize net customer and system benefits; deploys advanced communications, controls, platforms, and other technologies, based on a thoughtful grid architecture foundation i.e., Staff does not envision grid modernization for the sake of modernization, but expects that DSP will provide a clear pathway for utilities to take advantage of advanced technologies that demonstrate a net increase in operational efficiency and customer value.[10]

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[10] For a more detailed understanding of the evolving range of opportunities to meet modern distribution system needs, Staff suggests reviewing the US Department of Energy's *Modern Distribution Grid Report*. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx.

Considerations for DSP

In addition to the proposed drivers and outcomes, Staff presents the following list of considerations that represent a holding place for the breadth of important DSP elements for which an appropriate place in this framework will become clearer as OPUC works with utilities and stakeholders throughout this investigation:

- Grid modernization and aging infrastructure
- Increased DER penetration, exogenous and endogenous to the DSP process e.g., resulting from the DSP process, cost reductions, technological advancements, and other policy drivers such as Community Solar, Transportation Electrification, Energy Storage, Demand Response, and RVOS
- Evolving standards and the need for interoperability e.g., IEEE 1547
- The value of flexibility and the ability to respond to variability and uncertainty
- Resiliency, climate adaptation, and storm hardening
- Interfacing with the bulk system
- Integration with other planning processes, such as Smart Grid Reports and Transportation Electrification Plans
- Cybersecurity and safely harnessing data to support transparency and precision
- Customer choice and control
- The role and market for third-party providers
- Equity and the needs of underserved communities
- Accessibility of the distribution system for customers and third-parties based on system awareness, system constraints, and/or procedural challenges
- The role of R&D and pilots
- Staff's investigation into performance-base ratemaking and performance metrics

Proposed Scope

Staff recognizes that Oregon is not the first jurisdiction to engage in a DSP effort. In developing a proposed scope for the DSP investigation, Staff examined the breadth of procedural pathways created in other states to inform a plan that bridges the proposed drivers and outcomes for DSP.

Staff finds that a successful DSP investigation is iterative, adaptive to continued learnings, and involves considerable stakeholder engagement. To accomplish these ends, Staff proposes a phased approach that begins with a baseline assessment of the following:

- How do utilities currently plan for distribution system operations?
- What do the current plans look like?
- What does the current system look like?
- What are the known distribution system operations and planning needs?

Staff plans to open the first phase of the investigation with a series of educational workshops related to the questions above (see Figure 5.) The workshop process may begin with a policy-level discussion of stakeholder values, priorities, and desired outcomes; however, Staff expects that the majority of workshops will focus on technical discussions that create a shared understanding of utility distribution system operations, planning, and investments, along with emerging technology, markets, use cases, and valuation models.

FIGURE 5: POTENTIAL WORKSHOP CONTENT

Scoping

- Feedback on Staff proposed drivers and outcomes
- Feedback on Staff proposed investigation scope

Kick-off and DSP 101

- Overview of other state's regulatory efforts related to DSP
- Utilities review current DSP processes e.g., capital budgeting processes, project planning and selection processes, Smart Grid Reports and other grid modernization efforts, integration of DSP in IRPs, pilots and R&D
- Utilities review distribution system design principles e.g., how utilities plan and operate for reliability, resiliency, capacity, etc.
- Stakeholder values, priorities, and desired DSP outcomes

Principles of grid modernization – infrastructure and advanced technologies

- Overview of DSP concepts e.g., system data and visibility, controls, communications, technical standards/ requirements
- Utilities review current processes, projects, and etc.
- Stakeholder perspectives

Principles of grid modernization – forecasting, DER integration, and valuation

- Overview of DSP concepts
- Utilities review current processes, programs, and etc.
- Stakeholder perspectives

Final Perspectives

- Reviews Staff's draft proposal for DSP guidance
- Final utility and stakeholder perspectives

The initial phase of Staff's proposed investigation culminates with Commission guidance for utilities to file distribution system plans. In the interest of baselining and remaining adaptive, the Commission's initial guidance can be less formal than the IRP guidelines, providing a set of planning objectives and listing the data points and analyses that utilities are required to include in an initial DSP filing.[11] Further, Staff proposes that the initial DSP filing serve as a dry-run, which will receive significant Commission review, but not require Commission acknowledgement.

As the landscape continues to evolve and all parties develop expertise, subsequent phases will build on this baseline with continued expansion and refinement of Commission guidance for DSP.

Staff's proposed investigation scope is detailed in Figure 6 below.

[11] See Attachment B for an example of Minnesota PUC's Integrated Distribution Planning Requirements for Xcel. Staff proposes that initial Commission guidance could resemble this format.

FIGURE 6: PROPOSED DSP INVESTIGATION SCOPE

	Pre-Launch	Phase 1: Baselining	Phase 2: Assessment	Phase 3: Refinement
Timeframe	February - March 2019	March 2019 – December 2019	January 2020 – May 2021	June 2021 - ongoing
Goal	Identify the focus of and process for a DSP investigation.	• Begin developing a knowledge-base for the major principles of DSP. • Develop guidelines to evolve the smart-grid report into a robust (initial) distribution system plan.	Review the current state of each utility's system, identify near- and long-term needs and next steps to get to optimization.	Refine planning process, incorporate additional considerations and requirements
Process	• Staff whitepaper released: Outlines Staff proposal for DSP investigation. • Scoping workshop: Stakeholder feedback on Staff proposal i.e., establish whether OPUC has outlined the correct drivers, outcomes, phases, goals and deliverables. • Public meeting memo: Staff's final proposal requesting investigation.	• Workshops: Staff will conduct a series of workshops to establish a baseline understanding of distribution system planning fundamentals, current utility processes, and outstanding distribution planning needs. • Draft guidance: Staff releases draft proposal for DSP guidance. • Stakeholder comments/ workshop(s) as necessary. • Revised draft guidance • Final comments • Public meeting memo: Staff final proposal for DSP guidance.	• Establish individual dockets for each utility • Utilities file based on Commission guidance (~ 8 months) • OPUC and stakeholder engagement process (~ 6 months) ▪ Comments ▪ Workshops • Public meeting memo: Staff final recommendations (~April 2021)	• Continue to implement planning process as directed by Commission • Improve and evolve content, process, tools, and methodologies • Continue to incorporate evolving policy and operational requirements
Key Objective	Commission order opening investigation	Commission order adopting guidance for utilities to file initial DSPs	Commission orders accepting utilities' initial DSPs and direction to refine DSP process and/or DSP guidance	Commission acknowledgement of action plan and guidance for refinement of subsequent utility DSPs

Following the release of this whitepaper, Staff will hold a workshop to refine the proposed drivers, outcomes, and scope. Staff will incorporate feedback from the workshop into its proposed investigation and submit a formal request for the Commission to open the investigation. The subsequent phases, goals, milestones, and objectives will be shaped by feedback from stakeholders and any additional Commission guidance.

Conclusion

Since the initial Smart Grid Reports were filed in 2013, the OPUC, utilities, and stakeholders have been thoughtfully engaged in an effort to understand and adapt to an evolving distribution system landscape. As technology, policy, markets, and consumer interests evolve, regulatory structures must adapt to adequately consider these new and significant opportunities, uncertainties, and risks. Based on the need for insight and optimization, Staff proposes a thoughtful, phased approach to begin necessary steps towards transparent, robust, and holistic distribution system planning.

Attachment A – Invitation to Initial Scoping Workshop

Invitation to Distribution System Planning Workshop

Staff of the Public Utility Commission of Oregon (OPUC) will hold a scoping workshop to discuss and solicit input regarding an investigation into distribution system planning (DSP):

Date: Friday, March 1, 2019

Time: 9:30 a.m. – 12:30 p.m.

Location: Portland State Office Building
Room 1A
800 NE Oregon St, Portland, OR 97232

Workshop overview

Expectations for Oregon's electrical grid are changing. Technological advancements in grid infrastructure and distributed energy resources, combined with declining costs, evolving policies, and changing consumer interests are driving greater consideration for investments on the distribution system. OPUC Staff (Staff) believes that a holistic regulatory framework is necessary to ensure utilities are best positioned to capture customer value during this transition to a modern grid.

In the coming weeks, Staff plans to release a whitepaper outlining its proposal to launch a DSP investigation. At this March 1st workshop, stakeholders will provide feedback on Staff's proposed investigation. Following the workshop, Staff will modify its proposal as needed and request that the Commission launch an investigation into DSP at a public meeting.

Logistics

Staff's whitepaper, an agenda for the workshop, and call-in information for the workshop will be provided to this distribution list in advance of the March 1st meeting.

Please direct questions to:
Caroline Moore
(503) 480-9427
caroline.f.moore@state.or.us

If you have a disability and need accommodation to participate in this event, please let us know: (503) 480-9427 or caroline.f.moore@state.or.us

Attachment B – Background Reading List

Below is a non-exhaustive list of resources that may provide helpful context for readers of this whitepaper and participants in OPUC's DSP Investigation.

Oregon's Smart Grid Reports

- Latest smart gird reports:
    - Idaho Power Company: https://edocs.puc.state.or.us/efdocs/HAQ/um1675haq132224.pdf
    - PacifiCorp: https://edocs.puc.state.or.us/efdocs/HAQ/um1667haq11754.pdf
    - Portland General Electric: https://edocs.puc.state.or.us/efdocs/HAQ/um1657haq16327.pdf
- Commission Smart Grid Guidance: https://apps.puc.state.or.us/orders/2012ords/12-158.pdf

Industry Background Materials

- USDOE Grid Modernization Report (Vols. 1-3):
    - Vol. I Customer and State Policy Driven Functionality: https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf
    - Vol. II Advanced Technology Market Assessment: https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-II_v1_1.pdf
    - Vol. III Decision Guide: https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf
- Distribution System Planning – State Examples by Topic: https://epe.pnnl.gov/pdfs/DSP_State_Examples-PNNL-27366.pdf
- Distribution Systems 101 Webinar: http://nasuca.org/resources/webinars/distribution-101/
- Distribution System Planning 101 Webinar: http://nasuca.org/resources/webinars/utility-distribution-planning-101/

Process Example: Minnesota PUC

- Utility and stakeholder questionnaire (Document ID: 20174-131044-01): https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={307DE9F3-1F36-4CB1-AABA-96F0FCA6B1A8}&documentTitle=20174-131044-01
- Commission order approving integrated distribution planning filing requirements for Xcel Energy (Document ID: 20188-146119-01) : https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={F05A8C65-0000-CA19-880C-C130791904B2}&documentTitle=20188-146119-01
- Xcel's initial Integrated Distribution Plan (Document ID: 201811-147534-01): https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={E098D466-0000-C319-8EF6-08D47888D999}&documentTitle=201811-147534-01

March 1, 2019 DSP Workshop - Small Group Exercise Summary

The present system: Current distribution system planning and operations	**The future system:** Where distribution system planning and operations are heading
• **Utility planning practices** o The suite of distribution planning processes and whether they have evolved over time o Data and modeling used in distribution planning ▪ Forecast methodologies e.g., DER forecasts, electric vehicles (EVs), whether utilities forecast QFs locationally, whether utilities forecast areas of high penetration of energy efficient buildings ▪ Existing assumptions ▪ The levels of granularity available and used o Planning and investment timelines and timescales o The processes to identify system needs and solutions ▪ The role of research and development ▪ How customer needs and interests are considered o Characteristics of distribution system planning, such the fact that distribution system attributes change more rapidly than the bulk system o Planning principles, e.g., how utilities manage risk and uncertainty, how utilities balance grid needs and cost shifting o Shortfalls and risks associated with existing processes o Challenges to planning for DERs • **The state of utility plans and systems** o Short and long-term investment plans by regions/areas o Existing roadmaps and smart grid activities e.g. AMI utilization ▪ The mix of modern and traditional technologies in service o Existing data and metrics ▪ Location and size of existing DERs ▪ The DER contribution to peak ▪ Distribution substations and other "mainline" infrastructure ▪ Communications infrastructure, such as scada ▪ Reliability and resiliency metrics o Current valuation models (and what is missing or out of date) o Customer demographics, differences between classes • **Distribution system engineering and operations** o Distribution system 101 ▪ Components such as meters, feeders, reclosers ▪ Demand v energy ▪ Net load v capacity o Engineering basics, requirements, and standards such as IEEE 1547 o Protection and safety o How utilities integrate and manage DERs, including barriers and flexibility • **Related regulatory and utility practices** o How utilities recover investment costs and develop rates o How distribution planning connects to transmission planning	• **Emerging technologies and tools** o Data management, visualization, and sharing tools o Automation technologies o Advanced inverter functions (solar specifically) o AMI utilization o IT systems and software o Microgrids, energy storage, EVs, and other DERs o Reliability, safety, major events preparedness and recovery in remote communities o Advanced valuation methodologies ▪ The value of behind the meter solar + storage ▪ The value of resiliency ▪ The value of deferring distribution system investments ▪ Locational value of DERs ▪ Mechanisms for sending price signals ▪ How to consider value to customers and value to the utility o Non-wires solutions v. typical wires solutions o The timescale of deploying tools and interoperability o Third party aggregators and other services • **Developing a shared roadmap** o Where utilities want to be in the future o Where other stakeholders want to be in the future • **Engaging customers in DSP** o Understanding customer needs and expectations o Measuring customer interests and value propositions o Customer knowledge level e.g., understanding of DSP concepts, familiarity with regulatory processes o Communication and education channels • **Considerations for evolving DSP** o Managing customer price impacts ▪ The trade-offs for various customer classes ▪ How costs associated with DSP should be allocated o Data security and privacy, including third party access o Accuracy and timeliness of data o The rate of technology change and determining the correct time to invest? o How will new programs and investments will impact reliability o The role of interconnection in DSP o How planning processes and decisions can be more transparent o Sharing best practices among utilities o Opportunities to coordinate with public power o The time and resources required for DSP (compared to the existing process and compared to the benefits)

August 31, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 468
Dated August 17, 2021

Request:

Please describe in narrative form the process used to solicit potential Advanced Distribution Management System (ADMS) providers.

Response:

PGE engaged a consultant experienced with implementing ADMS at other utilities to work with business stakeholders to develop ADMS business requirements and use cases. These business requirements and use cases were packaged and a Request for Proposal (RFP) was created. A market survey was conducted; potential vendors with a viable product were short-listed and invited to respond to the RFP. Based on their responses, the two top vendors, one primary and one alternate, were selected.

September 3, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 470
Dated August 17, 2021

Request:

Please provide all responses to the solicitation process discussed above (for example, all proposals submitted in response to an RFP).

Response:

Confidential Attachment 470-A provides the five RFP responses received and PGE's internal evaluation of the four qualifying RFP responses. Page 5 of the evaluation provides the bidders' pricing proposals. Note that one bidder was disqualified early in the process due to its proposal not meeting PGE's requirements.

Attachment 470-A contains protected information and is subject to General Protective Order No. 21-206.

August 31, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 471
Dated August 17, 2021

Request:

Please describe in narrative form the evaluation process used to select the chosen ADMS provider.

Response:

In general, PGE evaluated each bidder's proposal based on a number of areas, including:

- The completeness of the proposal in addressing all topics covered by the RFP;
- Bidder's experience and past performance with clients that are similar in size, scope and complexity to PGE, subject to the references checked by PGE;
- The effectiveness, efficiency, innovativeness and creativity of bidder's proposed configuration of services;
- Bidder's willingness to assign and retain experienced resources to support PGE; and
- Bidder's willingness to accept liability for all services, even to the extent agreed upon services may be performed by subcontractors.

Additionally, PGE's ADMS project team evaluated all submitted bids using a detailed matrix that considered over 3,250 aspects of the bid requirements. Each criterion was evaluated as one of the following: "requirement met out of the box," "requirement will be met in the future," or "requirement will not be met." Based on this evaluation, we calculated the percentage of "met" requirements for each bidder. The two bidders with the highest "met sum" score proceeded as finalists.

The two finalists were invited to make presentations to the ADMS project team. The contract award was offered in early February 2019 with final negotiations based on use case review; the final contract was signed in August 2019.

October 1, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 833
Dated September 17, 2021

Request:

Please see Exhibit 800, page 31. Of the $30.6 million ADMS capital costs included in the rate case:

d. Please provide a list of individual projects;
e. Please provide the date each project is expected to be placed into service;
f. Please provide the FERC account category for each project (Intangible, Steam, Hydraulic, Other Production Plant, Transmission, Distribution, or General);
g. Please provide the final cost of the project at the time it was placed into service or the estimated final cost for projects not yet in service;
h. Please provide a brief narrative description of the nature of the project including why it is necessary and how ratepayers will benefit;
i. Please provide the project justification forms for each project; and
j. Please provide any engineering analysis, or similar supporting evidence that justifies construction of these projects.

Response:

d. There is only one funding project: P36879.
e. The expected in-service date is December 2021.
f. The software and associated implementation costs will be recorded to Intangible plant. Computer hardware will be recorded to General plant.
g. At the time of the rate case filing, the estimated final cost that was not yet in service was $27.4 million. $2.3 million of computer hardware has already closed to plant and there is $0.9 million of contingency. The total estimated final cost is approximately $30.6 million.
h. Section IV.B of PGE Exhibit 800 provides the requested information.
i. Confidential Attachment 833-A provides the requested information.
j. Confidential Attachment 833-B provides the requested information.

Confidential Attachments 833-A and 833-B contain protected information and are subject to General Protective Order No. 21-206.

Oregon

Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301
Mailing Address: PO Box 1088
Salem, OR 97308-1088
Consumer Services
1-800-522-2404
Local: 503-378-6600
Administrative Services
503-373-7394

September 17, 2021

JAKI FERCHLAND
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST, 1WTC-0702
PORTLAND OR 97204
Jacquelyn.Ferchland@pgn.com pge.opuc.filings@pgn.com

RE:

Docket No.	OPUC Request Nos.	Response Due By
UE 394	OPUC 841-842	October 1, 2021

Please provide responses to the following request for data by the due date. Please note that all responses must be posted to the PUC Huddle account. Contact the undersigned before the response due date noted above if the request is unclear or if you need more time. In the event any of the responses to the requests below include spreadsheets, the spreadsheets should be in electronic form with cell formulae intact.

Topic or Keyword: **Advanced Distribution Management System (ADMS)**

841. Please provide the underlying data for Table 6 ADMS O&M in Exhibit 800, page 34. Please provide all data in electronic workbook format with all cells and references complete.

842. Please see Exhibit 800, page 34:

    PGE is adding 28 new employees (14 Distribution System Operators, two Grid Tech Engineers, two Grid Tech Analysts, four Distribution Operation Engineers, two Trainers, one Simulator Specialist, one IT administrator, one GIS specialist, and one Distribution Operations Manager), in order to staff ADMS.

    a. Please provide a narrative description of the justification of the number of the new employees added to staff ADMS, as well as justification of the composition of titles of new employees added to staff ADMS.

    b. Please provide any underlying analysis, data, and research done to justify the number of the new employees added to staff ADMS, as well as to justify the composition of titles of new employees added to staff ADMS. Please cite the source(s) of any data and research used in this justification.

Please name your responsive file to include the Data Request number. Once you have posted your response to the Data Request to the PUC Huddle account, use the “Sharing” feature of Huddle to generate an email to authorized parties notifying them that the response has been posted. In the body of the generated email, list the Data Request number associated with your response.

You must mark confidential responses as such and post them to Huddle in the appropriate “Confidential” folder. Access to Confidential folders is limited to individuals who have signed the protective order. You should not send confidential documents (hard copy or electronic) separately to the Commission or its Staff; you should post confidential responses only to the Huddle account.

Should you need to request an extension to the due date for the data responses you will need to contact the staff attorney assigned to the case for approval.

Questions regarding the use of Huddle should be directed to puc.datarequests@puc.oregon.gov

/s/ Matt Muldoon, E-RFA, Manager

Staff Initiator(s): Nick Sayen nick.sayen@puc.oregon.gov (503) 510 4355

August 20, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 311
Dated August 6, 2021

Request:

Please see Table 1 on PGE / 800, Bekkedahl – Jenkins / 4.

a. Please provide an itemized list of all items in this table.
b. In your answer, please indicate the following:
    i. Cost
    ii. Voltage where applicable
    iii. In service date by day, month, and year
    iv. Whether these items were recently reclassified, and if not, whether a 7-factor test was applied to each of these items.
    v. Whether these are distribution or transmission items

Response:

Attachment 311-A provides the requested information.

Staff Exhibit

“Attachment 311-A”

is

filed in electronic format

August 24, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 006
Dated August 10, 2021

Request:

Please refer to PGE / 800 Bekkedahl – Jenkins / 4 Table 1. Please provide the following information for each project included in this table with gross plant greater than $1 million:

a. Project number and description;
b. Documents associated with project approval, including approval of any substantial changes;
c. Project management documents;
d. Capital spending by month; and
e. Date and amounts of transfers to plant.

Response:

a. PGE's response to OPUC Data Request No. 198 provides the requested information for certain projects. Attachment 006-A provides the requested information for the remaining projects.
b. PGE's response to OPUC Data Request No. 198 provides the requested information for certain projects. Confidential Attachment 006-B provides the requested information for the remaining projects.
c. PGE's response to OPUC Data Request No. 198 provides the requested information for certain projects. Confidential Attachment 006-B provides the requested information for the remaining projects.
d. Attachment 006-C provides the requested information.
e. Attachment 006-C provides the requested information.

Attachment 006-B contains protected information subject to Protective Order No. 21-206.

Staff Exhibit

“Attachment 006-C”

is

filed in electronic format

August 20, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 326
Dated August 6, 2021

Request:

For each of the projects the Company is requesting cost recovery for in Exhibit 801:

a. Please provide itemized costs of each project in Excel format with cell formulae intact.
b. Please indicate which of these projects have been previously acknowledged or not in an Oregon IRP, and in which Commission Order it was acknowledged or not acknowledged.
c. If any of these projects were acknowledged in an IRP, please provide the difference in costs between what was projected in an IRP and what actual costs the Company is asking recovery for.
d. Please itemize and provide a narrative justifying each loading associated with a cost escalation in part c.
e. Has the Company obtained all the required approvals for each of these projects (i.e., CPCNs and land use permits)? If not, please provide a list of approvals still required for construction of each of these projects and the anticipated timeline for a decision.
f. Please provide any and all interconnection studies associated with these projects (e.g., System Impact Study, Feasibility Study, and Facilities Study).

Response:

a. Attachment 326-A provides the requested information.
b. None of the projects were acknowledged in an Oregon IRP because they address issues on the PGE local transmission system, not the regional transmission grid.
c. Not applicable.
d. Not applicable.
e. All required approvals for each project have been received.
f. There are no interconnection studies associated with any of these projects.

Staff Exhibit

“Attachment 326-A”

is

filed in electronic format

September 28, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 758
Dated September 14, 2021

Request:

Please provide a) a copy and a narrative description of the PGE and Sensus settlement agreement referred to in the PJF and b) a narrative description of the terms of the agreement.

Response:

The Settlement Agreement between PGE and Sensus addresses the insufficient data received from a specific meter model and the plan for Sensus to correct the issue by providing deeply discounted new meters. PGE's return obligation was to provide Sensus evidence of a meter replacement in order for both parties to reconcile quantities of meters replaced.

Confidential Attachment 758-A provides the Settlement Agreement.

Confidential Attachment 758-A contains protected information and is subject to General Protective Order No. 21-206.

September 28, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 759
Dated September 14, 2021

Request:

The PJF states that to achieve value through the settlement agreement with Sensus, PGE must make the meter purchases 2017-2019:

a. Did PGE do so?

b. Did PGE make the purchases at the prices noted in the PJF.

If not, what was the cost consequence to PGE?

Response:

a. Yes.
b. Yes.

September 28, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 761
Dated September 14, 2021

Request:

What is the final total capital investment for P36470?

Response:

The final total capital investment for P36470 was $3,530,276.

September 28, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 757
Dated September 14, 2021

Request:

The PJF for P36470 requests approximately $4.2m to "exchange 12,000" Device Type 34 (DT 34) commercial meters with Device Type 49 (DT49) commercial meters.

a. When were the DT 34 meters installed?

b. Will PGE's investment in the DT 34 meters be fully depreciated prior to the exchange for DT49 meters? If not, will PGE write off any undepreciated investment for the DT 34 meters?

c. Please provide a narrative explaining part b above further.

Response:

a. The meters were installed between April 2019 and December 2020.

b. No. The investment will not be fully depreciated and PGE will write-off any undepreciated investment.

c. PGE uses group depreciation, which is common in the utility industry, in which asset lives are established for a group of assets and are not based on each individual asset. Some meters will be retired before, and some after, the established life. A gain or loss is not recorded on the retirement of an individual meter, as the retirement results in a debit to Accumulated Depreciation and a credit to Plant-in-Service.

   Actual additions and retirements are incorporated into future depreciation studies and used to determine if the current asset life is still appropriate or needs to be changed going forward. The result of any changes will impact the rate of depreciation expense at the effective date of the new depreciation study.

CASE: UE 394
WITNESS: NICK SAYEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 803

Confidential Exhibits in Support
Of Opening Testimony

October 25, 2021

September 3, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 470
Dated August 17, 2021

Request:

Please provide all responses to the solicitation process discussed above (for example, all proposals submitted in response to an RFP).

Response:

Confidential Attachment 470-A provides the five RFP responses received and PGE's internal evaluation of the four qualifying RFP responses. Page 5 of the evaluation provides the bidders' pricing proposals. Note that one bidder was disqualified early in the process due to its proposal not meeting PGE's requirements.

Attachment 470-A contains protected information and is subject to General Protective Order No. 21-206.

October 1, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 832
Dated September 17, 2021

Request:

Please provide the final total amount paid to selected ADMS provider under the contract.

Response:

Confidential Attachment 832-A provides the requested information.

Confidential Attachment 832-A contains protected information and is subject to General Protective Order No. 21-206.

[7] Attachment C to the Company's response to Staff DR 588, page 8.

October 1, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 833
Dated September 17, 2021

Request:

Please see Exhibit 800, page 31. Of the $30.6 million ADMS capital costs included in the rate case:

d. Please provide a list of individual projects;
e. Please provide the date each project is expected to be placed into service;
f. Please provide the FERC account category for each project (Intangible, Steam, Hydraulic, Other Production Plant, Transmission, Distribution, or General);
g. Please provide the final cost of the project at the time it was placed into service or the estimated final cost for projects not yet in service;
h. Please provide a brief narrative description of the nature of the project including why it is necessary and how ratepayers will benefit;
i. Please provide the project justification forms for each project; and
j. Please provide any engineering analysis, or similar supporting evidence that justifies construction of these projects.

Response:

d. There is only one funding project: P36879.
e. The expected in-service date is December 2021.
f. The software and associated implementation costs will be recorded to Intangible plant. Computer hardware will be recorded to General plant.
g. At the time of the rate case filing, the estimated final cost that was not yet in service was $27.4 million. $2.3 million of computer hardware has already closed to plant and there is $0.9 million of contingency. The total estimated final cost is approximately $30.6 million.
h. Section IV.B of PGE Exhibit 800 provides the requested information.
i. Confidential Attachment 833-A provides the requested information.
j. Confidential Attachment 833-B provides the requested information.

Confidential Attachments 833-A and 833-B contain protected information and are subject to General Protective Order No. 21-206.

October 1, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 842
Dated September 17, 2021

Request:

Please see Exhibit 800, page 34:

> *PGE is adding 28 new employees (14 Distribution System Operators, two Grid Tech Engineers, two Grid Tech Analysts, four Distribution Operation Engineers, two Trainers, one Simulator Specialist, one IT administrator, one GIS specialist, and one Distribution Operations Manager), in order to staff ADMS.*

a. Please provide a narrative description of the justification of the number of the new employees added to staff ADMS, as well as justification of the composition of titles of new employees added to staff ADMS.

b. Please provide any underlying analysis, data, and research done to justify the number of the new employees added to staff ADMS, as well as to justify the composition of titles of new employees added to staff ADMS. Please cite the source(s) of any data and research used in this justification.

Response:

a. Confidential Attachment 842-A provides the requested information.
b. Confidential Attachment 842-A provides the requested information.

Confidential Attachment 842-A contains protected information and is subject to General Protective Order No. 21-206.

August 25, 2021

To: Nadine Hanhan
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Supplemental Response to OPUC Data Request 334
Dated August 6, 2021

Request:

For each project in exhibit 801 where the Company determined that additional capacity was needed to support load service, please provide a narrative explanation of how the Company forecasted growing need or load for each particular project. Please provide all applicable distribution or transmission planning documents demonstrating forecasted load growth.

Initial Response (dated August 20, 2021):

Confidential Attachment 334-A contains documentation discussing the following projects listed in Exhibit 801:

- Harborton Reliability Project
- Blue Lake Phase II Project
- Marquam Substation Project
- Rock Creek Substation Project
- Roseway Substation Project
- McGill Substation Project
- Horizon VWR3 Project
- Silverton Capacity Addition Project
- Willbridge Substation Project
- Shute Capacity Addition Project
- Brookwood Substation Conversation Project (addressed in the Hillsboro Reliability Project documentation)

The Butler Substation Project and Helvetia Substation Project did not have white papers developed due to a large amount of load growth coming online during the short amount of time that was required for the implementation of these projects. These projects were expedited as a result.

Confidential Attachment 334-A contains protected information and is subject to General Protective Order No. 21-206.

Revised Response (dated August 25, 2021):

Confidential Attachment 334-A contains documentation discussing the following projects listed in Exhibit 801:

- Harborton Reliability Project
- Blue Lake Phase II Project
- Marquam Substation Project
- Rock Creek Substation Project
- Roseway Substation Project
- McGill Substation Project
- Silverton Capacity Addition Project
- Willbridge Substation Project
- Shute Capacity Addition Project
- Brookwood Substation Conversation Project (addressed in the Hillsboro Reliability Project documentation)

Highly Confidential Attachment 334-B contains documentation discussing Horizon VWR3 Project.

The Butler Substation Project and Helvetia Substation Project did not have white papers developed due to a large amount of load growth coming online during the short amount of time that was required for the implementation of these projects. These projects were expedited as a result.

Confidential Attachment 334-A contains protected information and is subject to General Protective Order No. 21-206.

Highly Confidential Attachment 334-B contains protected information and is subject to Modified Protective Order No. 21-237.

September 1, 2021

To: John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 198
Dated July 29, 2021

Request:

Regarding the responses to Staff Data Requests 142 and 143, please provide the project justification forms for each funding project number listed in UE 394_OPUC DR 142_Attach A.xlsx and UE 394_OPUC DR 143_Attach A.xlsx.

Initial Response (dated August 12, 2021):

Attachment 198-A provides the requested information.

Attachment 198-A contains protected information subject to Protective Order No. 21-206.

Revised Response (dated September 1, 2021)

Confidential Attachment 198-A provides the requested information with customer-specific information redacted and with supplemental pages to certain project justification forms that were inadvertently excluded from the initial response.

Confidential Attachment 198-A contains protected information and is subject to General Protective Order No. 21-206.

August 24, 2021

To: Jesse O. Gorsuch
Alliance of Western Energy Consumers

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to AWEC Data Request 006
Dated August 10, 2021

Request:

Please refer to PGE / 800 Bekkedahl – Jenkins / 4 Table 1. Please provide the following information for each project included in this table with gross plant greater than $1 million:

a. Project number and description;
b. Documents associated with project approval, including approval of any substantial changes;
c. Project management documents;
d. Capital spending by month; and
e. Date and amounts of transfers to plant.

Response:

a. PGE's response to OPUC Data Request No. 198 provides the requested information for certain projects. Attachment 006-A provides the requested information for the remaining projects.
b. PGE's response to OPUC Data Request No. 198 provides the requested information for certain projects. Confidential Attachment 006-B provides the requested information for the remaining projects.
c. PGE's response to OPUC Data Request No. 198 provides the requested information for certain projects. Confidential Attachment 006-B provides the requested information for the remaining projects.
d. Attachment 006-C provides the requested information.
e. Attachment 006-C provides the requested information.

Attachment 006-B contains protected information subject to Protective Order No. 21-206.

CASE: UE 394
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am the Policy and Economic Analysis manager employed in the Utility Strategy & Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. I discuss Staff's analysis and review of several issues in Portland General Electric's (PGE) general rate case. This includes proposed non-bypassable charges and the Company's load forecast for the test year.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. LOAD FORECAST

Q. How does PGE's 2022 load forecast compare to the previous general rate case, UE 335?

A. On a total Company basis, the 2022 load forecast is expected to increase by 7.6 percent from 2019, from 19,041 GWh to 20,497 GWh. For further comparison, the Company reported actuals for 2020 at 19,529 GWh. By far the largest increase by segment was industrial load, which accounted for 97 percent of the overall increase. The industrial load forecast increased by 30 percent or 1,409 GWh. The residential load forecast increases by 51 GWh or 3.52 percent, while the Commercial segment decreased by 12 GWh or negative 0.18 percent.

Q. Please describe the Company's general approach to load forecasting.

A. PGE utilizes a generally accepted standard for forecasting each customer class separately, which are further broken out by dwelling type, space heating type, or one of eighteen North America Industrial Classification System (NAICS) segments. Residential and commercial classes are the product of a use-per-customer regression and customer count forecast. Large industrial customer forecasts are based on information gathered from individual customers regarding their expected load in the coming years.

Q. Has the Company changed its forecast methodology from the last GRC?

A. Yes, however the changes overall are relatively minor. The only major new input to the model is to address the impacts of COVID-19 on load. The Company has also updated its inputs to reflect more currently available data.

Q. How does the Company propose to address the impacts of COVID-19?

A. PGE utilizes indicator variables reflecting different levels of COVID-19 related shutdowns to identify the impact of the pandemic on energy usage. PGE tested the specific variables based on the available historic data to test significance. Once the variables were identified, the Company made an assumption that the impacts of the pandemic would continue in perpetuity at 33 percent the impact. This assumption reflects what PGE is assuming will be the "new normal" moving forward as not everyone will return to the office or school in person.

Q. Does Staff support PGE's process for estimating the impacts of COVID-19 on load?

A. Yes. Staff largely supports PGE process for identification of the impact of COVID-19, but finds that the Company's evidentiary support for the long-term impact is somewhat deficient. Staff notes that this assumption can be further informed as new data becomes available and we progress further beyond the initial impacts of the pandemic. Staff recommends that the Company review this assumption throughout this filing and moving forward to ensure that the assumption is as accurate as possible.

Q. Do you also summarize how Covid-19 impacted other Staff review and analysis in this general rate case?

A. Yes. Please see Section 3 of this testimony.

Q. Please summarize the Company's residential load forecast methodology.

A. PGE utilizes Autoregressive Integrated Moving Average (ARIMA) models for its residential customer and demand forecasts. Like many other utilities, PGE breaks down its residential forecast into two components of load that are forecasted separately, use-per-customer (UPC) and number of customers. These components can be multiplied to obtain the load. Economic and weather variables are used as forecast drivers in the models. Somewhat unique to PGE is the use an outboard Energy Efficiency adjustment, which utilizes energy efficiency investment projections from Energy Trust of Oregon (ETO) for consumers as an after-the-fact adjustment to regression results to account for future energy efficiency gains from SB 838 funded projects.

Q. Does Staff support the use of an ARIMA model for forecasting load?

A. Yes. ARIMA models are used by all Oregon-regulated utilities. Some switched to ARIMA models following recommendations by Staff. ARIMA models work well for forecasting electricity demand because of their ability to model data with trends. This is because the model can be made to handle non-stationarity through differencing if necessary.

Q. What is non-stationarity and how does differencing solve the issue?

A. Non-stationarity can be a number of things, but in general it means that the predicted variable does not have constant statistical properties over time. For example, in variables that increase over time such as population, the average value would not remain constant. Regression models attempt to identify constant relationships between variables in order to predict future values; if the relationship of two variables does not remain constant because of a trend, then the result of the regression could be spurious.

Differencing is one of the simplest ways to deal with this issue, i.e., a non-stationary series. Instead of estimating the gross level of the variable of interest, differencing looks at the change from year to year. If the change from year to year is not stationary, then another difference is taken, and the forecast looks at the change in the difference from year to year.

A crude analogy to understand a non-difference regression would be trying to predict the location of a car. If the car were moving, the first difference would then try to use the speed of a car to parse out where a car is. If the car was not moving at a constant speed, the second difference would look at how fast the car is accelerating to then solve how fast the car is moving and then solve where it is. This process of differentiating is repeated until stationarity is achieved. The number of differences (d) required to achieve stationarity is denoted as the "I" (Integrated) part of the ARIMA model.

Q. Describe the Company's primary forecast driver for residential UPC?

A. PGE uses weather as the primary forecast driver for UPC. Weather describes a high proportion of the usages-per-customer, when used as the only variable in an ARIMA regression, it accounts for roughly 96 percent of the total variation in the UPC data.

To model normal weather, the historical weather data is broken down into heating degree days (HDD) and cooling degree days (CDD) for each month in the historic data set. The Company continues to utilize a hinge-fit model for normal weather, which estimates a linear trend for weather beginning in 1975. This assumption concludes that next year will likely have warmer weather than the previous year, whereas all other OPUC regulated utilities utilize a moving-average approach that assumes past n-number of years represent future weather.

PGE's hinge-fit approach was approved in UE 335 and has been utilized by PGE since. Staff continues to evaluate this relatively new assumption but has no recommended adjustments at this time.

Q. Please describe the Company's commercial and small industrial forecast.

A. PGE forecasts these two classes in a similar manner. The Company utilizes an ARIMA model to forecast the total demand for each rate class. Weather related variables are the primary forecast driver. Non-manufacturing or non-farm employment are the economic drivers included in the commercial model. Manufactory employment is used as the major economic driver in the industrial model.

Q. How does the Company forecast large industrial customer demand?

A. A small number of the largest industrial customers and data centers are individually forecast based on input from the customer and key customer managers. This is a common practice by utilities in the region. As noted previously, industrial load is expected to be the driving factor in load growth for the Company in 2022. This is largely due to large energy intensive projects such as data centers scheduled to come online in the coming year.

Q. How did Staff analyze the Company's load forecast?

A. Staff reviewed each model individually to identify any potential regression assumption violations, model and variable selection and appropriateness, and potential improvements to forecast accuracy or robustness. Any model with potential concerns for Staff was then reconstructed by Staff to provide a greater depth of understanding and to determine the merit of any concerns.

Q. Did Staff determine any models were of concern?

A. Yes, however Staff's primary concern is not with the model specification or methodology but with the outboard energy efficiency (EE) adjustment that alters the results of the residential, commercial, and industrial load forecast.

Q. What is Staff's concern with the EE adjustment?

A. As stated in the Company's opening testimony, two legislative bills have passed in the state with the goal of promoting EE. SB 1149 was enacted in 1999 and established the 3 percent public purpose charge to fund and encourage energy conservation. The impacts of this bill are assumed to be captured in the trends present in historic data fed into the load forecasting models.

SB 838 passed in 2007 to fund the acquisition by ETO of more low-cost, electric, EE opportunities. These investments are the impetus for PGE's outboard adjustment. Staff believes that there is no incremental difference between the historic data, which includes both SB 838 and SB 1149 investment, and future impacts of these bills. Staff has raised concerns regarding this practice in both UE 319 and UE 335 as SB 838 was enacted nearly fifteen years ago. The total impact of PGE's adjustment is a reduction of 159.3 GWh.

In UE 335, parties agreed to a 40% reduction in the overall impact of this adjustment, although the Company argues in opening testimony that it led to a less accurate forecast. Staff disagrees that there is necessarily a correlation between agreed to adjustment and accuracy of the forecast. Forecast error is common and a single data point cannot be used to justify the inclusion or exclusion of a model specification based on sound theoretical reasoning.

The simplest illustration of Staff's concern is that there were roughly six years between the implementation of SB 1149 and SB 838, yet PGE has been adjusting for the incremental impacts of SB 838 and assuming SB 1149 impacts are embedded in the data for 12 years. Staff notes that the Company's input data used to forecast the use-per-customer variable begins in January 2010, two years after the implementation of SB 838. There is no historic data, currently being used by the Company as an input in any relevant use-per-customer model that precedes the implementation of SB 838.

Q. Why does the timing of the input data matter?

A. The regression models utilize the relationships between variables to estimate the future value of the variable of interest. In a simple regression, the model statistically identifies how the variable of interest moves when only a single input variable is changed. This is done iteratively for each variable over the historic data to find the average impact of each input variable on the variable of interest. Then the model looks at the forecasts (or estimates the future values based on trends) of the input variables, to add up all of the individual impacts on the variable of interest to identify what the expected value will be to produce the forecast.

EE measures have a direct impact on load. By using historic load, which includes the previous investment from SB 1149 and SB 838, the model is estimating relationships which already assume a particular level of EE investment. This is referred to as "training" the model. In the case of COVID-19, it was difficult to estimate what the future impacts of the pandemic would be on load, until sufficient data was available to train the model. For PGE's COVID adjustment, the Company created a specific variable that identifies which data points are subject to the pandemic related impacts. However as Staff noted, the amount of data points is somewhat limited and additional data would be valuable for training the model.

In the case of EE, the Company testifies, "PGE recognizes that as time passes since the enactment of SB 838 in 2007, the level of embedded savings becomes less clear. While PGE is interested in investigating alternative approaches, at this time we believe our current adjustment mechanism performs well and is both appropriate and necessary for the development of PGE's energy deliveries forecast."1 Staff appreciates the Company's discussion on the topic, however Staff is concerned that the

[1] PGE/1000, Riter/8, line 16.

Company concludes that embedded savings become less clear over time but that the out-of-model adjustment is still necessary. Staff disagrees that the out-of-model adjustment is necessary. The relevant data is already being fed into the model, and only if future savings were assumed to be incrementally larger than previous savings would an adjustment be needed.

Q. Has Staff reviewed the levels of expected savings from SB 838?

A. Yes. As a comparison, Staff reviewed both the historic funding of both SB 1149 and SB 838 as well as the expected future savings from each. Figures 1 and 2 below show, the level of savings and funding, particularly in the near term, are relatively similar with little justifiable evidence for disparate treatment between SB 1149 and SB 838.

Figure 1

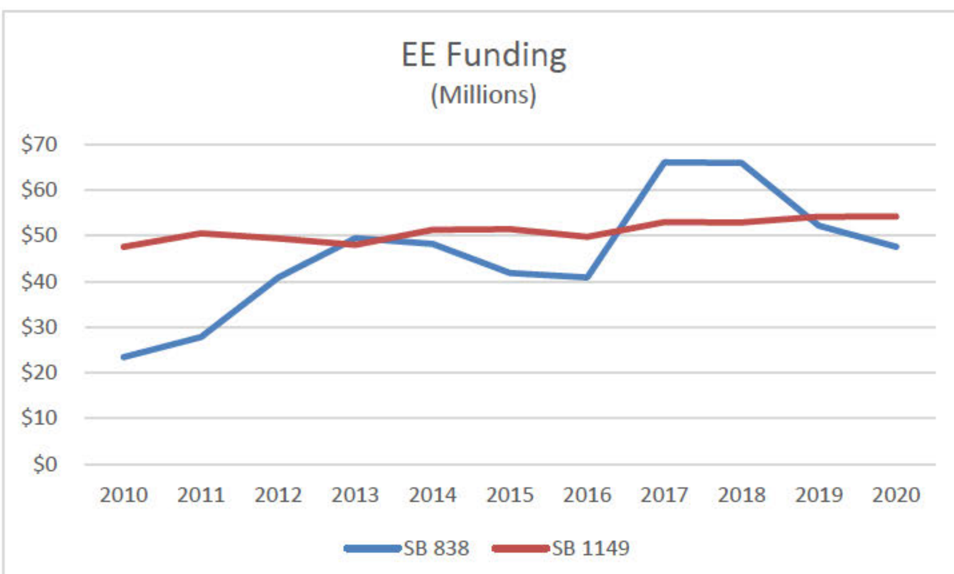
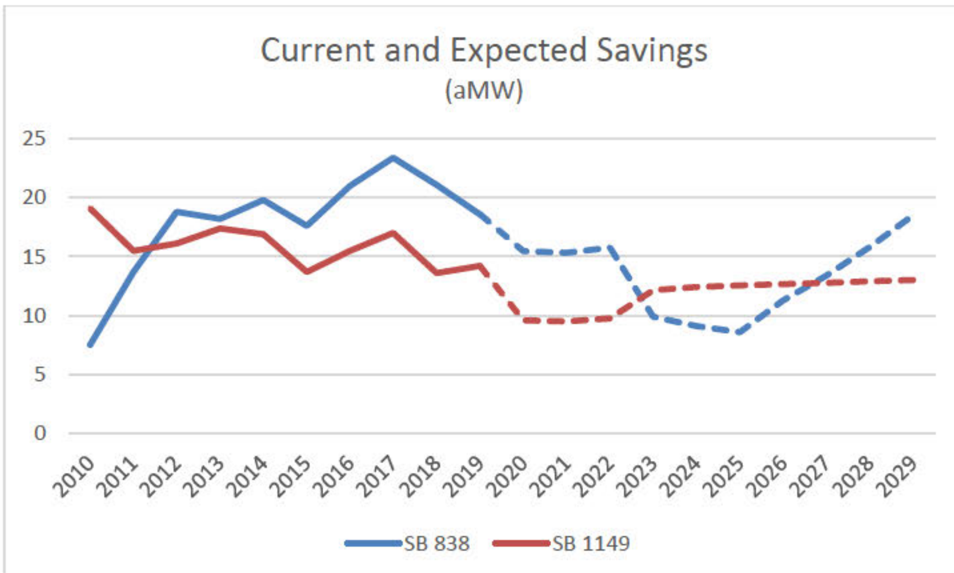


Figure 1 shows that the level of funding for the two programs is indeed somewhat different. SB 1149 has generally had smaller incremental changes from year to year. Staff assumes this is why PGE has argued that

SB 1149 is embedded in historic data, while SB 838 requires an additional adjustment. However, Staff notes that the model is not trying to forecast EE expenditures, but instead concerned with the level of savings that result from the EE investments.

Figure 2



As evidenced by Figure 2, savings from SB 838 and SB 1149 have been relatively similar over-time. There is no discernable difference in the variability of either mandate. In looking at Figure 2, expected savings, particularly through the test year, are expected to remain consistent with past performance. Thus, there is no evidence that past experience is not a good predictor of the future.

Q. What are your conclusions regarding PGE's outboard adjustment for EE?

A. There is no clear, increasing trend in expected savings that warrant additional steps to adjust for EE. The model already includes the impacts of past EE spending and savings for both SB 1149 and SB 838, and that historic data is a good indicator of what the future values will be. In PGE's current process, the model is calculating loads with EE spending, and predicting loads with EE spending, and then PGE is adding further EE spending on top of it. The expected savings from SB 838 is below the average savings being fed into the model. This means that the model will likely over-estimate the impact of EE in the forecast. Therefore, not only does PGE's current process effectively double count the effects of SB 838 impacts on load, but the model itself is being fed EE values that are higher than expected future values, further biasing the resulting forecast.

Q. What is Staff's recommendation for the load forecast?

A. Staff recommends that PGE remove its outboard EE adjustment, which results in an increase to the load forecast of approximately 159 GWhs in the Test Year. This equates to current rates recovering approximately $14.8 million more than PGE has estimated and reduces the overall requested increase by the same amount.

Q. Does this conclude your opening testimony on load forecasting?

A. Yes.

ISSUE 2. DIRECT ACCESS RELATED CHARGES

Q. Please describe PGE's proposal for Direct Access related charges.

A. PGE proposes an update to the direct access (DA) customer relocation fee, which is associated with Schedule 600, and to allocate the costs of two Schedules to DA customers, Schedule 137, Solar Payment Option (SPO), and Schedule 150, Transportation Electrification cost recovery.

Q. Please describe PGE's proposed update to Schedule 600.

A. Rule K of PGE's tariff states that the relocation fee applies, "[w]hen a Customer moves 100% of its operation from an existing service location enrolled under Direct Access to a [single] new service location and elects to continue Direct Access Service at such new service location." PGE's previous GRC resulted in a stipulated agreement which directed PGE to either justify the $7000 DA customer relocation fee or to propose changes to it. After reviewing the costs to PGE associated with handling a location change of a DA customer, PGE is proposing to reduce the relocation fee to $5000.

Q. Does Staff have concerns over PGE's proposed update to the ESS relocation fee?

A. No, the relocation fee seems reasonable. Staff reviewed the work papers that itemize the time and costs associated with the steps necessary to implement a change of location for an ESS. Staff also reviewed PacifiCorp's tariff to compare the relative costs associated with a customer change, however Staff was unable to identify a similar fee in PacifiCorp's tariff. PacifiCorp's rules do not specify the particular situation when a customer requests a location change, but do note that the fee schedule associated with charges to ESSs lists “Other Work at ESS Request” as having a “cost-based price.”[2]

Staff also reviewed PGE’s previously filed estimates for the labor and steps required to process the relocation of a DA customer, based on a 2013 estimate that resulted in the initial $7000 fee. In comparing the two, Staff notes the majority of the costs associated with a location change are similar between the two estimations, however the updated costs estimate a lower overall time impact on the Direct Access Operations group. After review of the updated costs, Staff finds the updated cost estimates reasonable.

Q. Please describe PGE’s proposed allocation for Schedule 137 and 150.

A. PGE proposes to include Schedule 137, which recovers costs associated with the Solar Payment Option (SPO), and Schedule 150, Transportation Electrification cost recovery in charges that would be allocated to long-term DA customers. PGE proposes to allocate the costs to DA customers on a revenue basis so that DA customers would pay the same as they would if they were COS customers.

Q. Is there any recent Commission precedent regarding the allocation of non-bypassable costs to DA customers?

A. Yes. Commission Order No. 20-173 approved PGE’s allocation methodology for Schedule 136, Community Solar Program Cost Recovery, whereby DA customers were charged as if they were COS customers and allocations were

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[2] https://www.pacificpower.net/content/dam/pcorp/documents/en/pacificpower/rates-regulation/oregon/tariffs/rates/600_ESS_Charges.pdf

made based on revenues In that case the Commission “[found] that the Community Solar Program is a legislatively-mandated program that is intended to provide for broad public, customer, and community benefits such that all customers should contribute to the recovery of costs for the program.”

However, Order No. 20-173 offers no precedent in terms of how to calculate the rates themselves. The Commission noted, “[W]e agree with [AWEC] that more review of the specific calculation and cost allocation methodology for those costs is warranted.” The Commission went on to say that “[o]ur decision regarding Community Solar Program costs is not precedential for future consideration of costs associated with other public policy directives. We will consider more broadly the question of whether and how costs associated with public policy directives should apply to direct access customers as part of the UM 2024 investigation.”

Thus, the Commission did approve PGE’s proposed methodology for part of Schedule 136, but noted that further discussion should take place, and deferred to UM 2024 as the appropriate venue.

Q. What is Staff’s response to PGE’s proposal?

A. Staff believes that the proper venue to identify a long-term solution for all non-bypassable charges for DA customers is through the general investigation into long-term direct access, Docket UM 2024. That docket provides a chance to discuss policy and theoretical considerations in a holistic manner. The proper allocation of costs should also be informed by each utility’s Long-Run Incremental Cost (LRIC) studies. However, given

PGE's current proposal, a solution for the appropriate allocation must be found until the conclusion of UM 2024.

Staff believes there are two questions that must be answered prior to implementation or approval of PGE's proposal. The first is whether these two programs (Schedule 137 and 150) should be paid for by DA customers. The second question what the allocation methodology should be if the costs should be allocated to DA customers.

Q. Does Staff believe that DA customers should pay for the costs associated with these schedules?

A. Yes. In Order No. 20-173, the Commission concluded that a program that is legislatively-mandated and intended to provide for board public, customer, and community benefits could meet the threshold for allocation to DA customers. The programs underlying both Schedules at issue in PGE's request satisfy this standard.

Schedule 137

HB 3039 required the Commission to "establish a pilot program for each electric company to demonstrate the use and effectiveness of volumetric incentive rates and payments for electricity delivered from solar photovoltaic energy systems." PGE implemented the pilot through Schedules 205 and 206 consistent with the Commission orders. Schedule 137 is designed to recover the costs associated with the pilot. In UE 237, PGE specifically addresses the concept of spreading the costs to LTDA customers, "PGE is not proposing to recover pilot program costs from large nonresidential customers who select a multi-year direct access option, under Schedules 485 and 489."[3] However, based on the Commission's recent direction, Staff believes this program qualifies as a legislatively-mandated program intended to provide for broad public benefits.

Schedule 150

HB 2165 recently mandated a fee paid for by all customers, including DA customers, set to one quarter of one percent of the total revenues. The funds collected being used to support and integrate transportation electrification (TE). PGE is seeking to recover costs that were previously deferred for amortization through Schedule 150, which would not at this point qualify under HB 2165.

Staff believes that HB 2165 provides sufficient discretion to determine that previous TE investment qualifies as a legislatively driven for the public good. Staff looks forward to further discussion on the matter, but at this time believes that the state legislature has provided the Commission with a direction to support TE as in the public interest. As such, costs associated with previous TE investment also provide benefit to the general public and thus should be paid for by all customers.

Q. Does Staff agree with PGE's proposed allocation methodology?

A. Staff reiterates that it believes the appropriate venue for discussion of the proper allocation methodology for non-bypassable charges is in Docket UM 2024. However, given the Commission's recent approval of a similar

[3] UE 237, PGE/100, Macfarlane/5, lines 14-15 PGE

allocation methodology in Commission Order No. 20-173, Staff believes a similar approach is reasonable as PGE has proposed. One benefit of the current process is that the LRIC allocations are examined in the rate case, allowing for a more in-depth and up-to-date allocation. For further discussion of Staff's review of the LRIC, please see Staff/1400.

ISSUE 3. COVID-19 IMPACTS SUMMARY

Q. How has Staff addressed the impacts of COVID-19 in its review of the issues in this case?

A. COVID-19 (COVID) brought about extreme changes and disruptions to consumers and utilities. Shipping and construction delays, energy usage pattern changes, and staffing issues were some of the indirect impacts of the pandemic on the utilities operations. Staff commends all utilities on their ability to continue to provide safe and reliable power during this time of uncertainty and change, and believes that PGE has largely done a good job of considering the impacts COVID has had on its operations in this rate case. While reviewing the issues in this case, Staff kept the potential impacts of COVID in mind to identify any areas where there could be a resulting impact on costs or rates. A few of the areas where COVID clearly had an impact on issues related to the rate case are the load forecast, transmission & distribution (T&D) additions, uncollectible expense, decoupling, and other revenue, Staff has no adjustments specifically related to COVID, but will continue to monitor the issues as the case progresses.

Q. Please summarize the impacts of COVID on the load forecast.

A. As mentioned previously in my testimony, the Company has added an additional indicator variable to its load forecast models to account for the impacts of the pandemic and specifically the stay-at-home orders issues in the state. The Company saw an increase in residential usage and decrease in commercial usage as a result of the safety measures. PGE predicts that the 33 percent of the impacts of COVID will continue through the test year, meaning elevated residential usage and a decline in commercial usage. Please see Issue 1 of my testimony for further details.

Q. Please summarize the impacts of COVID on Transmission and Distribution additions.

A. An overarching concern of Staff's with respect to COVID-19 is the Company's ability to acquire the necessary equipment, labor, and materials in the past couple years to meet its used and useful deadline of April 30, 2022. While the Company indicated that for 2021, it reduced its total capital budget by $50 million, a large portion of which was T&D, Staff, in its review of PGE's Project Justification Forms (PJFs), sought areas where COVID-19 may have impacted the Company's ability to meet project deadlines. As discussed in further detail in Exhibit Staff/700, Hanhan, the PJFs generally did not provide sufficient detail for project milestones (e.g., planning vs. execution) and how project timelines and their budgets may have been impacted due to COVID-19. Please refer to Exhibit Staff/700 for further details.

Q. Please summarize the impacts of COVID on uncollectible expense.

A. Uncollectible expense for PGE has increased as COVID related disruptions have caused increases in arrears. The Commission has addressed COVID related uncollectible expenses in part, through a deferral as stipulated in Docket No. UM 2064. In PGE's current general rate case, it is assumed that any debt above the Commission-approved uncollectible rate, will be included in the COVID related deferral. Please see Staff/300 for further detail of uncollectible expense.

Q. Please summarize the impacts of COVID on decoupling.

A. The Company is requesting to allow carryover of the balances associated with Sales Normalization Adjustment (SNA) under-collections in excess of the 2 percent limiter for recovery in subsequent years. Staff notes that COVID related impacts on the economy has resulted in suppressed non-residential usage and allowing carryover across multiple years would hinder economic recovery of an already struggling sector of the economy. Please see Staff/400 for further discussion on decoupling.

Q. Please summarize the impacts of COVID on other revenue.

A. The Company saw a substantive drop-off in other revenue in 2020 due to the Commission suspension of disconnections and late payment charges.[4] As a result, Staff proposes special consideration when examining the 2020 other revenue expense for determination of the appropriate level of other revenue expense in the test year. Please see Staff/1300 for more information on other revenue.

Q. Has Staff concluded that all of the impacts of COVID have been addressed in this rate case testimony?

A. No. Staff will continue to review the issues, other stakeholder testimony, and the Company's reply testimony to determine if COVID related issues have sufficiently been addressed. As noted earlier, Staff examined all the issues for

[4] See UM 2114, Commission Order No. 20-324.

potential interactions with the pandemic, however the impacts are wide-ranging and parties continue to gain information about what the "new normal" might look like for estimation of costs and revenues in the test year. As Staff gathers new information, it will continue to address these issues on the record.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATION STATEMENT

NAME:	Scott Gibbens
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Science, Economics, University of Oregon Masters of Science, Economics, University of Oregon

EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I have been the power cost team manager since January 2017. I have worked on the following power cost dockets: PAC UE 307, UE 309, UE 323, UE 327, UE 339, UE 344, UE 356, UE 361, and current UE 375 and UE 379. PGE UE 308, UE 310, UE 319, UE 329, UE 335, UE 346, UE 359, UE 362, and current UE 377. IPC UE 301, 305, UE 314, UE 320, UE 333, UE 336, UE 350, UE 354, UE 366, and current UE 376. I've also performed analysis and review on a variety of other issues at the Commission.

I have reviewed issues and made recommendations to the Commission in the following general rate cases: AVA UG 325, UG 366 and current UG 389; NWN UG 344, and current UG 388; PAC current UE 374; PGE UE 319, and UE 335; and CNG UG 305, UG 347 and current UG 390. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UE 394
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1000
REDACTED

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Moya Enright. I am a Senior Economist employed in the Rates, Finance & Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1001.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. FUEL STOCK

Q. What is Fuel Stock?

A. Fuel Stock is included in rate base and represents a stock of fuel typically stored at a generating plant to ensure adequate fuel supply is always available to operate the plant.[1] Fuel Stock complements the expense forecasted in the Company's Annual Update Tariff (AUT) for fuel requirements that may be delivered at differing times and locations during the year. Fuel Stock differs from the Company's AUT fuel because instead of being a pass-through cost, the Company earns a return on its Fuel Stock.

Q. What Fuel Stock value has the Company claimed in this filing?

A. The Company has included a total of $17.4 million in fuel stock. As shown in Figure 1, this is split into approximately:

- $3.6 million in coal stock,
- $5.0 million in CO2 Allowances,
- $1.0 million in Natural Gas, and
- $7.8 million in Diesel. [2]

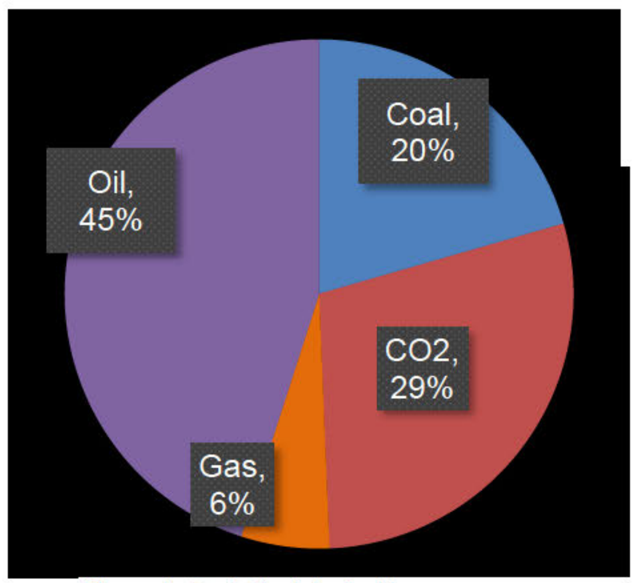

Figure 1 - Fuel Stock by fuel type

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[1] PGE's diesel and coal stock is located directly at the plants using the fuels, specifically, coal and diesel are held at Colstrip, and diesel is held at Beaver. PGE's natural gas stock is located at North Mist, connected to Port Westward Units 1 and 2, and the Beaver plants by a 13-mile pipeline. See Exhibit Staff/1002, Enright/48-51, PGE's response to Staff DR 827, section (c).

[2] See Exhibit Staff/1002, Enright/58, Attachment A to PGE's response to Staff DR 910.

Q. How did the Company determine its required Fuel Stock for revenue requirement?

A. The Company did not base its determination of Fuel Stock on a specific Fuel Stock policy.[3] Instead, PGE forecasted its oil, coal, and CO2 allowance requirements based on the actual amount and value of stock on hand as of March 31, 2021.[4] PGE forecasted the value of its natural gas stock by adjusting the value of Natural Gas stored at Mist on March 31, 2021 by the forecasted storage balance change for the year ahead.[5]

Q. Is this a reasonable method for determining a value for Fuel Stock to include in rate base?

A. Only if PGE has reasonable policies or practices for how much of each fuel to keep on hand and is vigilant in following this practice or policy, which is not true for PGE's stock of coal.

As for the Company's determination of CO2 allowance stock, Staff believes that the forecasted CO2 allowance stock provides no value to customers and should be excluded in its entirety for the reasons explained below.

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3 See Exhibit Staff/1002, Enright/55, PGE's response to Staff DR 828, section (a).

4 Staff has verified that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of Fuel Stock has been forecasted for Boardman in this filing, reflecting the retirement of the generator in late 2020. See Exhibit Staff/1002, Enright/52, Confidential Attachment A to PGE's response to Staff DR 827.

5 The year's storage balance change is forecasted in the Company's AUT filings. See Exhibit/1002, Enright/19-20, PGE response to Staff DR 778, section (d), and Docket Nos. UE 377 and UE 391.

Q. What are PGE's practices for how much fuel to keep on hand?

A. For gas at North Mist, approximately 1.2 billion cubic feet (BCF) of gas is maintained in storage to ensure the Port Westward thermal plant can be dispatched for seven days exclusively on storage gas should a gas pipeline disruption occur. This amount is supplemented with additional gas depending on the value derived from PGE's gas storage modeling in MONET.[6]

PGE's coal Fuel Stock is kept at Colstrip, which is a mine mouth plant.[7] The Company asserts that a small quantity of coal is kept on site to help regulate the volume of coal entering the plant, and to manage issues that arise at the plant or at the mine. For example, the plant may go off-line for a few hours or few days and coal from the mine would be held on site to be burned when the plant resumes operation. The Company also asserts that coal stock held on-site can be blended with coal coming directly from the mine to ensure that quality meets the standard needed for the units.[8] According to PGE, coal on hand varies from a few days' supply, up to several days' supply of both units 3 and 4 at full operation.[9]

Diesel inventory levels are based on the amount required to fuel PGE's Beaver Plant operations at full load for approximately four to five days during heavy load hours, in the event of a natural gas disruption or if it is economical

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6 As calculated in the Company's AUT. See Exhibit/1002, Enright/19-20, PGE response to Staff DR 778, section (d), and Exhibit/1002, Enright/24-25, PGE response to Staff DR 780.
7 Located directly next to a coal mine.
8 See Exhibit/1002, Enright/24-25, PGE response to Staff DR 780.
9 See Exhibit/1002, Enright/24-25, PGE response to Staff DR 780.

to run the plant on diesel fuel.[10] Diesel is required at Colstrip to start the units, and typically, Colstrip stores sufficient diesel on site to support three to five starts per year for each unit.[11]

For CO2 allowances,[12] the Company has not provided any specific detail regarding its practices.[13] However Staff discovery and analysis show that PGE's CO2 allowance requirements vary greatly through the three-year compliance periods,[14] and that the Company's March 31, 2021 stock (the basis of PGE'S Test Year forecast), represents the three-year peak of the Company's CO2 allowance holding as PGE prepared for the end of the 2018 – 2020 compliance period. Notably, the CO2 allowances held in stock provide no equivalent value to stock of oil, gas, or coal, which allow the Company to generate power.

Q. Does Staff have concerns with the Company's stated practices regarding the amount of Fuel Stock to be kept on hand?

A. Yes. Staff believes it would benefit PGE to conduct a risk/benefit or other analysis to support its practices regarding the amount of coal, gas and diesel kept on hand.

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10 See Exhibit/1002, Enright/68-71, PGE response to Staff DR 925, section (b).
11 See Exhibit/1002, Enright/24-25, PGE response to Staff DR 780.
12 PGE uses CO2 allowances to meet its obligation to the CARB, which arises when it imports CO2 emitting power to California.
13 See Exhibit/1002, Enright/24-25, PGE response to Staff DR 780, and Exhibit/1002, Enright/55, PGE response to Staff DR 828.
14 The California Air Resources Board (CARB) requires CO2 allowances to be retired in three-year cycles. As detailed in Figure 2 below, PGE has the flexibility to retire very small quantities of CO2 allowances following years one and two, and the majority of their three-year CO2 allowance requirement following year three.

Staff has an adjustment related to the amount of coal PGE has on hand for Colstrip, which does not necessarily correspond with PGE's stated practice described above.

Finally, Staff believes that PGE's practice for determining CO2 Fuel Stock is unreasonable, as holding CO2 allowance stock provides no value to customers, and should be excluded in its entirety.

Q. With regard to forecasted coal stock, has Staff analyzed PGE's forecasted coal stock compared with its generation requirements?

A. Yes. Staff found that the Fuel Stock the Company proposes to include in rate base assumes there will be 128,059[15] tons of coal stock held at Colstrip during the test year. This amount of coal would provide sufficient fuel for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[16] days of generation based on Colstrip's average use over the past 24 months. This is also equivalent to the Company's fuel requirement for its **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[17] highest demand days in the same period.

Q. Please explain Staff's concerns, and recommended adjustment for PGE's forecasted coal stock.

A. Staff's discovery shows that PGE intends to hold a few days' supply of coal, up to several days' supply, of both units 3 and 4 at full operation at Colstrip.[18]

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15 See Exhibit Staff/1002, Enright/58, Attachment A to PGE's response to Staff DR 910.
16 See Exhibit/1002, Enright/52, Confidential Attachment A to PGE response to Staff DR 827.
17 See Exhibit/1002, Enright/52, Confidential Attachment A to PGE response to Staff DR 827.
18 See Exhibit/1002, Enright/24-25, PGE response to Staff DR 780.

However Staff analysis shows that PGE is forecasting to hold several multiples of that amount in the Test Year.

Colstrip is a mine mouth plant, receiving coal deliveries almost daily,[19,20] and without interruption for the past decade at least.[21] Given this, along with the fact that the Company does not have a risk benefit analysis or other procedure to justify its fuel stock forecast,[22] Staff recommends the Commission limit the Company's cost recovery for coal stock held at Colstrip to 7 days of its historical maximum requirement.

Staff's recommendation results in a disallowance of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from rate base, equivalent to **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]** percent of the Company's coal stock. This disallowance of coal stock that is surplus to the Company's requirements helps to reduce the risk of customers paying a return for stock which is held at no benefit to them.

19 On average, Colstrip received coal deliveries on 357 days a year over the past three years. See Exhibit/1002, Enright/66-67, PGE response to Staff DR 921, section (a).

20 In one calendar day, it is possible to deliver enough coal to Colstrip to fuel the plant for **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of generation at its highest historical demand. See Exhibit/1002, Enright/66-67, PGE response to Staff DR 921, section (b), and Exhibit/1002, Enright/52, Confidential Attachment A to PGE response to Staff DR 827.

21 See Exhibit/1002, Enright/66-67, PGE response to Staff DR 921, section (b).

22 See Exhibit/1002, Enright/55, PGE response to Staff DR 828.

Q. With regard to forecasted CO2 allowances stock, please explain Staff's concerns.

A. Staff is concerned by the inclusion of CO2 allowances stock in the Company's filing, because holding stock of CO2 allowances simply provides no benefit to the Company's customers. The reasons are threefold:

First, CO2 allowances are retired in portions the November after the compliance year ends. PGE actually collects the revenue required to purchase the CO2 allowances long before the compliance obligation becomes due. This is illustrated in Figure 2 below.[23]

Second, as CO2 allowances are retired in portions in November of the following year, the Company has ample opportunity to purchase the allowances on the open market or at quarterly auctions. In short, the physical benefit of holding stock, which exists for fuels such a coal and diesel which can run a generator, does not exist for CO2 allowances.

Third, even if budgeting to hold stock of CO2 allowances provides an opportunity for PGE to purchase the allowances at advantageous prices, the price of CO2 allowances passed through to customers in rates reflects the forecasted market price.[24] PGE's customers do not benefit if PGE manages to purchase the CO2 allowances at a lower price than forecasted.

[23] Staff analysis shows that in each CARB compliance period since 2013, PGE has retired **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percentage of its compliance obligation following the first years of the compliance period, and the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** percentage of its compliance obligation following the final year of the compliance period. See Exhibit/1002, Enright/60, Confidential Attachment A to PGE response to Staff DR 911, and Exhibit/1002, Enright/61-62, PGE response to Staff DR 912, section (a).

[24] See Exhibit/1002, Enright/65, Confidential attachment A to PGE response to Staff DR 914.

Emissions Year	PGE Collects Revenue	Compliance Obligation Due Date	Percent of Compliance Obligation Due
2018	2018	November 1, 2019	30% of 2018 covered emissions
2019	2019	November 1, 2020	30% of 2019 covered emissions
2020	2020	November 1, 2021	70% of 2018 and 2019, and 100% of 2020 covered emissions

Figure 2 - Timeline for surrender of CO2 allowances during three-year compliance period[25]

Q. Are there any other reasons why the $5 million in CO2 Allowances is inappropriate?

A. Yes. PGE's forecast of CO2 allowance Fuel Stock is based on stock held on March 31, 2021, and includes CO2 allowances belonging to a past period (the 2018-2020 compliance period), and which **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[26] PGE held a whopping **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[27] percent of the 2018-2020 compliance period's CO2 allowance requirement in stock in March 2021, making the forecasted stock

25 See CARB publication "What Does My Company Need To Do To Comply With The Cap-And-Trade Regulation?" page 6: http://ww2.arb.ca.gov/sites/default/files/cap-and-trade/guidance/chapter3.pdf

26 See Exhibit/1002, Enright/60, Confidential Attachment A to PGE response to Staff DR 911.

27 See Exhibit/1002, Enright/60, Confidential Attachment A to PGE response to Staff DR 911, and Exhibit/1002, Enright/61-62, PGE response to Staff DR 912, section (a).

of CO2 allowances in no way representative of the stock of CO2 allowances that may be held during the 2022 test year.

Q. With regard to CO2 allowances stock, what is Staff's recommendation?

A. Staff recommends that the Commission disallow the Company's $5,004,122 CO2 allowances stock in its entirety, to reflect the fact that holding CO2 allowances stock provides no benefit to customers.

Q. Please summarize Staff's recommendations regarding the Company's forecasted Fuel Stock.

A. Staff recommends a total adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Staff recommends the Commission:

1. Disallow **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the Company's forecasted coal stock,
2. Disallow the Company's $5,004,122 CO2 allowances stock in its entirety.

ISSUE 2. FARADAY REPOWERING PROJECT

Q. Please provide some background on the Faraday Repowering Project.

A. The Faraday Repowering Project (the Repowering) involves the replacement of PGE's original Faraday Hydro Plant on the Clackamas River, specifically Units 1 – 5 and the original powerhouse (no upgrade to Unit 6 is necessary). The new powerhouse will consist of two higher efficiency turbines (Units 7 and 8), and a reinforced concrete powerhouse with new flood protection systems. Latest estimates show the Repowering is expected to be complete in March 2022.[28]

Q. Has the Commission dealt with this issue prior to the current case?

A. This filing is the first in which rate recovery for the Repowering will be considered by the Commission; however, the power cost impacts of the Repowering have already been considered in the Company's 2021 and 2022 AUT filings.[29] The Repowering was not addressed in an IRP filing.

Q. What is the cost of the Project?

A. Latest estimates show the total expected capital cost of the Repowering, including Allowance for Funds Used During Construction (AFUDC), is $119.4 million.[30]

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28 PGE/700, Jenkins-Cristea/5, line 23.
29 Docket No.s UE 377 and UE 391.
30 PGE/700, Jenkins-Cristea/4, lines 20-21.

Q. What is the standard by which Staff is analyzing the Repowering?

A. As explained in Fox/200, Staff is applying two standards in its review of utility plant. First, Staff reviews to ensure that the plant will be "used and useful," i.e., placed into service, prior to the effective date of the rates, and second, prudent.

With respect to the prudence of the Company's investment in the Repowering, Staff's analysis is based on the nature of the utility's deliberative process and the prudence of its decision based on the information that was reasonably available at the time the Company made its decision, not the final outcome of its decision. The prudence standard revolves around the question of whether an action is reasonable given the facts that are known and knowable at the time that the decision is made.[31]

Further, NARUC stresses that a utility must follow a course of conduct that a capably managed utility would have followed in light of existing and reasonably knowable circumstances. NARUC also presents the following factors that should be considered when determining prudence:

- utility executives are financial and technical experts;
- prevailing practice is relevant but not determinative;
- the utility's legal obligation to provide safe, reasonable, and adequate service at lowest cost;
- the initial utility decision and its subsequent utility response to changing circumstances; and

[31] See *In the Matter of PacifiCorp* Request *for a General Rate Revision,* Docket No. UE 246, Order No. 12-493, Dec 20, 2012, at 25 (Dec. 20, 2012).

- prudence analysis is not based on hindsight.[32,33]

Q. Will the Faraday generator units be "used and useful" on the rate effective date, April 30, 2022?

A. PGE is forecasting that Units 7 and 8 will be operational on March 31, 2022. Staff is concerned however, that delays in the project schedule may lead to the new generator units not yet being used and useful by the rate effective date April 30, 2022.

Q. Is Staff aware of any delays to the completion of the Faraday repowering?

A. Recent documentation provided by PGE shows Faraday Units 7 and 8 being synchronized to the grid on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[34] This, along with the commissioning of both units, which has been forecasted to occur during the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** weeks after synchronization,[35] would result in the new turbine generators being "used and useful" no sooner than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

32 "Management Audits / Prudency," NARUC, 2014. See: https://pubs.naruc.org/pub.cfm?id=537CC901-2354-D714-5154-339AD3909936
33 *In the Matter of PacifiCorp Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 25 (Dec. 20, 2012).
34 See Exhibit/1002, Enright/36-38, PGE Confidential response to Staff DR 817.
35 See Exhibit/1002, Enright/9-10, Confidential Attachment B to PGE response to Staff DR 591, page 34.

Q. Does Staff have a recommendation regarding the potential delays to the Faraday repowering project completion date?

A. Yes. Staff's recommendation, detailed in Staff/200, that PGE provide attestations for projects over $1 million placed into service in January to April 2022, will ensure that costs relating to the Faraday repowering project are not included in rates if the plant is not yet fully operational on the rate effective date.

Q. Has Staff identified any issues with the prudence of the Repowering?

A. Yes. Staff has found several issues:

1. PGE has provided little evidence to support the prudence of the Repowering in its filing;[36]
2. Staff has identified significant shortcomings in the selection of the project; and
3. Staff has identified mismanagement of the Company's contracting for construction.

These issues will be addressed in more detail below.

Q. Staff notes that PGE has provided little evidence to establish the prudence of the Repowering, please provide more information on this issue.

A. When a utility seeks to recover the cost of a newly acquired asset, the utility must prove the acquisition was prudent.[37] Although the Faraday Repowering

[36] PGE/700, Jenkins-Cristea/5, lines 1 - 21.
[37] See PUC website: https://www.oregon.gov/puc/utilities/Pages/Energy-Planning.aspx

project is not a new acquisition, it is equivalent in size and cost to PGE's largest acquisition in recent years and PGE must show its decision to repower Faraday was prudent.[38]

Despite the $119.4 million price tag of the Repowering, PGE has made little effort to prove its prudence, limiting its entire testimony on the need for the repowering to just one page of text in this docket.[39] Further, despite issues with the Faraday powerhouse building being known for many years prior to the decision to undertake this project, PGE did not include the project in any Integrated Resource Planning (IRP) filing.

Q. What is the significance of the project not being considered in an IRP filing?

A. The IRP process helps to identify the lowest practical and least risk cost at which a utility can deliver reliable energy services to its customers, and requires utilities to use analytical tools that are capable of fairly evaluating and comparing the costs and benefits of various resource options. The IRP process also allows the Commission, Staff, and other stakeholders to be involved in decisions affecting ratepayers.

By excluding the Repowering from an IRP filing,[40] and conducting an extremely limited analysis of its options, as detailed below, the Company

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38 PGE's 2020 investment in Wheatridge for example, had an initial price tag of $157.4 million. Docket No. UE 370, PGE/100, Armstrong-Batzler/16.
39 PGE/700, Jenkins-Cristea/5, lines 1 - 21.
40 PGE submitted IRP filings in February 2013 and November 2016.

engaged in an expensive project without taking advantage of an IRP review process.

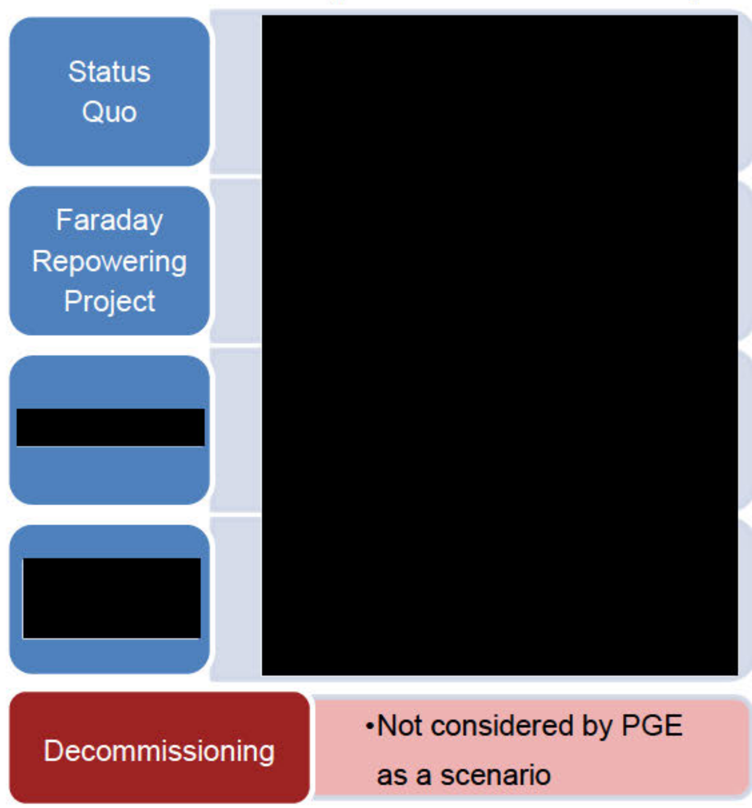
Q. What is Staff's recommendation regarding this sub-issue?

A. Staff recommends that the Commission instruct PGE to include significant capital investments such as repowerings in IRP filings going forward, and to fully demonstrate the prudency of its investments in future filings.

Q. Staff has observed shortcomings in the Company's selection of the project. Please explain the process the Company followed to select the project.

A. PGE selected the Faraday Repowering Project in 2016, after conducting an economic analysis in which it compared several scenarios, as shown in Confidential Figure 3.[41]

[BEGIN CONFIDENTIAL]



Confidential Figure 3 - Scenarios considered by PGE in 2016

[END CONFIDENTIAL]

The result of the Company's analysis showed that the repowering scenario had a **[BEGIN CONFIDENTIAL]** [redacted]

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41 See Exhibit/1002, Enright/5-7, PGE Confidential response to Staff DR 588, section (c).

[redacted] **[END CONFIDENTIAL]**[42] NPV than the status quo scenario, and as a result, the Repowering was selected.

Q. What other factors influenced the Company's decision?

A. PGE points to several other considerations that influenced its choice:

1. The poor state of the old powerhouse,[43]
2. The years remaining in the license period,[44]
3. A perceived regional capacity shortage and energy market price volatility,[45]
4. PGE and Oregon's decarbonization goals,[46]
5. Plant reliability, including the unpredictability of outages,[47] and Faraday's role supporting of PGE's diverse resource portfolio,
6. Production Tax Credits (PTCs) [48] available for incremental generation, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**,[49] and
7. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[50]

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[42] See Exhibit/1002, Enright/3, Confidential Attachment A to PGE response to Staff DR 584.
[43] Identified as a cause of increased O&M costs, unpredictable maintenance, and flooding concerns. See PGE/700, Jenkins-Cristea/5, lines 2-5.
[44] The Faraday license period runs until 2055. See PGE/700, Jenkins-Cristea/5, line 6.
[45] PGE/700, Jenkins-Cristea/5.
[46] See PGE/700, Jenkins-Cristea/5, lines 17-18.
[47] See Exhibit/1002, Enright/4, PGE response to Staff DR 587.
[48] PTCs are passed back to customers as a benefit through PGE's net variable power costs.
[49] See Exhibit/1002, Enright/1-2, PGE Confidential response to Staff DR 584, section (a).
[50] See Exhibit/1002, Enright/5-7, PGE Confidential response to Staff DR 588, section (b).

Q. What issues has Staff identified with the Company's process?

A. Staff has identified multiple issues:

1. The Company did not consider decommissioning as a scenario when choosing between its options.[51]
2. The Company did not **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** each available option.
3. The Company used **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** general construction costs in its 2016 NPV estimate.

Q. The Company did not consider decommissioning, nor did it [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL] each available option. Why is this a concern?**

A. Because of the significant capital required, it would have been appropriate for the Company to have considered all options available for Faraday, including its decommissioning. Similarly, the Company dismissed the options to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[52] Although PGE asserts that both options were not ideal due to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**,[53] PGE missed the opportunity to assess the value that the imperfect projects might create.

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[51] See Exhibit/1002, Enright/26, PGE response to Staff DR 812.
[52] See Exhibit/1002, Enright/5-7, PGE Confidential response to Staff DR 588, section (c).
[53] See Exhibit/1002, Enright/5-7, PGE Confidential response to Staff DR 588, section (c).

Q. General construction costs were [BEGIN CONFIDENTIAL] [redacted] **[BEGIN CONFIDENTIAL]. Is Staff attempting to judge the Company based on hindsight, rather than what was known or knowable at the time?**

A. No. In the case of the project selection, general construction costs were estimated to total **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This amount was revised **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** during the course of the project, a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on the original estimate.[54]

As financial and technical experts, Staff considers that PGE's executives should have been capable of providing a more accurate cost estimate. However, PGE **[BEGIN CONFIDENTIAL]** [redacted][55] [redacted] **[END CONFIDENTIAL]**.[56]

Although PGE claims that its construction budget **[BEGIN CONFIDENTIAL]** [redacted][57] [redacted]

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54 See Exhibit/1002, Enright/28-33, Confidential Attachment A to PGE response to Staff DR 814, pages 11-15.

55 A study into the Faraday powerhouse upgrade, prepared by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. See Exhibit/1002, Enright/77-79, Confidential Attachment A to PGE response to CUB DR 022 in Docket No. UE 356, provided as Confidential Attachment B to PGE response to CUB DR 006.

56 See Exhibit/1002, Enright/39-40, PGE Confidential response to Staff DR 818 section (a), and Exhibit/1002, Enright/44-46, PGE Confidential response to Staff DR 822 section (a).

57 See Exhibit/1002, Enright/39-40, PGE Confidential response to Staff DR 818 section (a).

[redacted] [END CONFIDENTIAL]. As a result, PGE's financial and technical experts committed to fund the project spend while paying insufficient attention to its analysis of the costs and benefits of the project itself.

Q. NARUC also recommends considering the utility response to changing circumstances. Has Staff considered this?

A. Yes. Staff investigated the response of PGE's Board of Directors (BOD) to the cost increases. On **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[58]

Despite general construction costs **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from the BOD to Company management relating to the matter.[59] Additionally, there were **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[60]

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58 See Exhibit/1002, Enright/28-33, Confidential Attachment A to PGE response to Staff DR 814, page 14.

59 See Exhibit/1002, Enright/27, PGE Confidential response to Staff DR 814, section (b).

60 See Exhibit/1002, Enright/27, PGE Confidential response to Staff DR 814, section (c).

Subsequent **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[61]

Staff questions the apparent lack of concern or scrutiny by the BOD, and its lack of feedback to PGE management regarding the significant budgeting error.

Q. Staff's adjustment for the Faraday plant is made up of several components. What is Staff's recommendation regarding this sub-issue?

A. Staff recommends that the Commission disallow 10 percent of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in general construction costs, representing approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in capital costs.

Staff's recommended disallowance is intended to reflect PGE's over-reliance on the "known" estimated construction costs, and to correct for PGE's financial and technical experts making no attempt to verify or investigate the data used in its NPV calculation. Had PGE made an effort to investigate the "knowable," its NPV analysis would have been better informed, and may have resulted in an alternative project at Faraday.

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[61] PGE asserts that the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. See Exhibit/1002, Enright/34-35, PGE response to Staff DR 815.

Q. Staff is also alleging mismanagement of the Company's contracting for construction. Please explain.

A. The Company's original contract for construction services **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**."[62,63] As a result, when the construction contractor **[BEGIN CONFIDENTIAL]** [redacted][64] [redacted],[65] [redacted] **[END CONFIDENTIAL]**.

Q. Was including "critical milestones" in a contract with third parties "known or knowable" at the time that the contract was signed by PGE?

A. Yes. The use of critical milestones in contracting is common and well established. Staff has verified that PGE was aware of their use as early as 2016. This is evidenced by a draft Power Purchase Agreement (PPA) submitted by PGE to the Commission in 2016. In the PPA, PGE used critical milestones to ensure that the renewable energy producer would meet a

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62 See Exhibit/1002, Enright/47, PGE Confidential response to Staff DR 825.

63 Critical milestones allow the buyer to hold contractor accountable for meeting certain key or time-sensitive milestones. Critical milestones may be used to protect the buyer from financial harm caused by delays by assessing liquidated damages for Contractor's failure to meet the critical milestone.

64 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. See Exhibit/1002, Enright/17-18, PGE Confidential response to Staff DR 592.

65 See Exhibit/1002, Enright/41, PGE Confidential response to Staff DR 820, and See Exhibit/1002, Enright/42-43, PGE Confidential response to Staff DR 821.

required Guaranteed Commercial Operation Date, by imposing damages for non-compliance.[66]

PGE's 2016 draft PPA is directly equivalent to the contract that PGE signed with its construction contractor for the Faraday Repowering. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Please explain how PGE could have known at the outset that [BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]?**

A. Staff discovery demonstrates that **[BEGIN CONFIDENTIAL]** [redacted][67] [redacted] **[END CONFIDENTIAL]**.[68]

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66 Docket No. UM 1773, filing dated July 13, 2016, Appendix C, "Wholesale Renewable Power Purchase Agreement Between Portland General Electric Company And [Seller]."

67 **[BEGIN CONFIDENTIAL]** [redacted] **[BEGIN CONFIDENTIAL]**. See Exhibit/1002, Enright/56, PGE Confidential response to Staff DR 908, section (a), and Exhibit/1002, Enright/11-12, Confidential Attachment C to PGE response to Staff DR 591, page 8.

68 See Exhibit/1002, Enright/11-12, Confidential Attachment C to PGE response to Staff DR 591, page 8.

Q. Has Staff considered the utility's response to the changing circumstances, as recommended by NARUC?

A. Yes. Once the Company realized the contractor **[BEGIN CONFIDENTIAL]** [redacted][69]

[redacted][70] [redacted][71]

[redacted] **[END CONFIDENTIAL]**.

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[69] See Exhibit/1002, Enright/41, PGE Confidential response to Staff DR 820.

[70] Liquidated damages are an estimate of the actual damages that would likely be sustained in the event of a delay.

[71] See Exhibit/1002, Enright/42-43, PGE Confidential response to Staff DR 821.

Staff's opinion is that PGE should have been capable of correctly contracting from the outset, or at the very least recognized the shortcomings of its abilities, drawing on the help of outside experts at that early stage.

Q. What is Staff's recommendation regarding this sub-issue?

A. Staff recommends that the Commission disallow **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in costs relating to the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** from rate base. Staff recommends that the Commission allow PGE to recover legal and accountancy costs related to the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**,[72] and allow PGE to also keep any liquidated damages payable under its **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** construction contract.[73]

Q. Please summarize Staff's recommendations relating to the Faraday Repowering project.

A. Staff recommends that the Commission require PGE to provide an attestation that the Faraday plant has been placed into service prior to April 30, 2022.

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72 Specifically, costs incurred when **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

73 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Based on recent estimated completion dates for the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** critical milestones, Staff estimates **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. See Exhibit/1002, Enright/14-16, Confidential Attachment D to PGE response to Staff DR 591 (Amendment 3 to PGE's construction contract, pages 3 – 5), and Exhibit/1002, Enright/36-38, PGE Confidential response to Staff DR 817.

Assuming that the plant is used and useful prior to the rate effective date, Staff recommends that the Commission: allow cost recovery for the Faraday Repower Project (currently forecasted as $119.4 million),[74] subject to the following instruction and adjustments:

- Instruct PGE to include significant capital investments such as repowerings in IRP filings going forward, and to fully demonstrate the prudency of its investments in future filings,
- Disallow 10 percent of the May 2019 **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** general construction costs, equal to a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction to rate base, and
- Disallow $14 million in costs relating to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, allow PGE to recover legal and accountancy costs related to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, and allow PGE to also keep any liquidated damages payable under its **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** construction contract.

[74] PGE/700, Jenkins-Cristea/4, lines 20-21.

ISSUE 3. AFFILIATED INTEREST TRANSACTIONS

Q. What transactions between PGE and its affiliates are forecasted for the 2022 test year?

A. PGE forecasts Administrative and General (A&G) expenses totaling $2.5 million to be billed to two of its subsidiaries in the 2022 test year, namely 121 Southwest Salmon Corporation (the owner of the World Trade Center building), and the PGE Foundation.[75]

PGE forecasts that it will be billed $6.2 million for rent by its affiliate 121 Southwest Salmon Corporation. This amount represents rent for a smaller share of the World Trade Center (WTC) building than previously, following some of PGE's operations moving to the Integrated Operations Center (IOC) in April 2022.[76] No payments are forecasted between PGE and its affiliate "Salmon Springs Hospitality Group."

Costs assigned by PGE to Affiliates		
Labor and Labor Loadings	$	1,598,635
Corporate Overhead	$	42,354
Electricity	$	766,000
Vehicle	$	10,419
Insurance	$	183,694
Costs assigned by Affiliates to PGE		
Rent	$	6,164,518

Figure 4 - Forecasted payments between PGE and affiliates

Expenses will be billed to the affiliates in accordance with the Company's Cost Allocation Manual, and

[75] See Exhibit/1002, Enright/73-76, Attachments and PGE responses to Staff DRs 808 and 809.

[76] PGE's move to the IOC is expected to be complete in April 2022, and will result in a 27 percent decrease in the office space that PGE rents at the WTC building. See Exhibit/1002, Enright/72, PGE response to Staff DR 926.

approved Master Services Agreement, and are broken down as shown in Figure 4.[77]

Q. Does Staff recommend an adjustment to the forecasted transactions?

A. No.

Q. Does Staff have any further concerns relating to the Company's forecasted Affiliated Interest transactions?

A. Yes. Staff notes that on September 10, 2021, the Company filed an application for approval of an affiliated interest transaction with a new affiliated interest, Portland Renewable Resource Company (PRR).[78] Multiple parties have petitioned to intervene in the Company's filing. PGE's current forecast of payments between it and affiliates includes no forecasted transactions with PRR.

Q. Does Staff have any recommendations regarding the Company's affiliate interest transactions?

A. Staff recommends that PGE update the current filing to reflect forecasted payments between it and its new affiliate PRR, in accordance with the recommendations resulting from the conclusion of Docket No. UI 461.

Staff is not taking a position on the prudence of PGE's forecasted transactions with PRR until Docket No. UI 461 is concluded.

Q. Does this conclude your testimony?

A. Yes.

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[77] See May 28, 2021, filing in Docket No. RE 64 for PGE's current Cost Allocation Manual. See March 24, 2006, filing in Docket No. UI 248 for PGE's current Master Service Agreement.

[78] See Docket No. UI 461.

CASE: UE 394
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	Moya Enright
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Rates, Finance, and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Energy Risk Professional Certification. Global Association of Risk Professionals. M.Sc. Political Science, 2015. University of Amsterdam. M.Sc. Investment, Treasury and Banking, 2011. Dublin City University. B.A. International Business and Languages, 2008. Dublin City University through a joint curriculum with École Supérieure de Commerce de Montpellier.
EXPERIENCE:	Senior Utility and Energy Analyst at OPUC since January 2019. Energy Trader for Meridian Energy from 2015 to 2019. Meridian Energy is a power generator and retailer operating both in New Zealand and Australia. Trading and Operations Analyst at Tynagh Energy from 2011 to 2013. Tynagh Energy is an independent power producer operating in the Republic of Ireland. Senior Electricity Market Controller at EirGrid from 2008 to 2011. EirGrid is the Irish electricity Transmission System Operator. It operates the Single Electricity Market for the Republic of Ireland and Northern Ireland. Accounts Assistant roles from 2004 to 2008, including Audit Intern at KPMG in Northern Ireland.

CASE: UE 394
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support
Of Opening Testimony

October 25, 2021

September 14, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 584
Dated August 31, 2021

Request:

Regarding the response to CUB DR 006 (specifically UE 359_CUB DR 021_Attach A_CONF.xlsm) and the project justification form provided in response to Staff DR 198 (P36167 Funding Justification.pdf, page 5 of 7) showing [redacted] respectively,

a. Please confirm or deny that the Company relied on either model when evaluating its decision to proceed with the powerhouse and turbine upgrades.

b. Please provide all documentation and modeling underlying the [redacted] million.

c. Please provide any other cost benefit analysis or modeling the Company relied upon when evaluating its decision to proceed with the powerhouse and turbine upgrades.

d. Please provide the most recent NPV estimates for the project.

Response:

[redacted]

[redacted]

Attachments 584-A and 584-B are protected information subject to Protective Order No. 21-206.

Confidential Staff Exhibit

"Confidential Attachment A to PGE Response to Staff DR 584"

is filed in electronic format only

September 14, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 587
Dated August 31, 2021

Request:

Please provide a detailed list and explanation of any considerations not included NPV calculations that the Company relied upon when deciding it was prudent to proceed with the project despite the negative NPV's.

Response:

In addition to the NPV analysis provided in PGE's response to OPUC Data Request No. 584, Attachment 584-A, PGE also relied on the following factors when PGE gave the notice to proceed to the Faraday Repowering project contractor:

- Enhance plant safety:
    - The age of numerous plant equipment had exceeded their useful lives and were expected to impact plant availability and reliability and require increased operation and maintenance costs.
    - Lack of seismic reinforcement: The Faraday facility was lacking seismic reinforcement to ensure structural integrity during a seismic event.
- Ensure Plant Reliability:
    - The age of plant equipment was expected to create issues in predicting the type and duration of unplanned outages due to limited access to skilled craft, parts, and materials.
    - The plant was at increased risk of flooding. High flow events were likely to occur during the remaining life of the plant license and the duration and cost for cleaning, repair, or replacement of structures and equipment due to flooding was expected to significantly impact costs and plant reliability.
- Flood risk mitigation:
    - Generator floor and windows of powerhouse were below extreme high flow event water levels, putting the plant at risk of flooding,
    - Extreme high-flow events were expected to become more frequent in the region,
    - Response to and preparation for predicted high flow events required redeployment of labor and materials to shut down and prepare the facility for flooding at increased expected costs.

September 14, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to Confidential OPUC Data Request 588
Dated August 31, 2021

Request:

Regarding the project justification form (P36167 Funding Justification.pdf) provided in response to Staff DR 198,

a. Regarding "Page 2 of 7" and the statement [redacted] thereon, please provide a detailed explanation of the underlying circumstances.

b. Regarding "Page 3 of 7" and the statement [redacted] please provide a detailed explanation of each bulleted item thereunder.

c. Regarding "Page 3 of 7" and the statement [redacted] please provide a detailed explanation of each option listed thereunder including why each option was selected or not selected.

d. "For each alternative detailed in response to section "c," please provide the NPV calculation used to inform the Company's choice to proceed with the Faraday repowering. If a NPV was not calculated for each alternative to inform decision making, please provide a detailed explanation of why this was not done."

e. Regarding "Page 2 of 7" and the [redacted] please provide a detailed explanation of this, and how it arose.

f. Regarding the "Revision Summary" shown on "Page 1 of 7 and the individual revisions listed thereon (14, 17, 43, etc.)," for each revision, please provide a detailed narrative explanation of each revision and an itemized accounting of the individual items comprising the change in total project cost for each revision.

Response:

[redacted]

[redacted]

PGE’s response to this request is protected information subject to Protective Order No. 21-206.

September 14, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to Confidential OPUC Data Request 591
Dated August 31, 2021

Request:

With regard to the contract between PGE and its construction contractor for the Faraday repowering,

a. Please provide a copy of the original contract.
b. Please provide the [redacted] referenced on page 6 of the project justification form (P36167 Funding Justification.pdf).
c. Please provide an explanation of each change made in the [redacted] and the reason that PGE supported each change.
d. Please provide any other related contracts or amendments.

Response:

[redacted]

Attachments 591-A, 591-B, 591-C, 591-D, and PGE's response to this request are protected information subject to Protective Order No. 21-206.

Confidential Staff Exhibit

"Confidential Attachment B to PGE Response to Staff DR 591"

is voluminous. The referenced page 34 is included in this section, and remaining pages are filed in electronic format.

[redacted]

Confidential Staff Exhibit

“Confidential Attachment C to PGE Response to Staff DR 591”

is voluminous. The referenced page 8 is included in this section, and remaining pages are filed in electronic format.

[redacted]

Confidential Staff Exhibit

"Confidential Attachment D to PGE Response to Staff DR 591"

is voluminous. The referenced pages 3-5 are included in this section, and remaining pages are filed in electronic format.

[redacted]

[redacted]

[redacted]

September 14, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to Confidential OPUC Data Request 592
Dated August 31, 2021

Request:

Regarding the [redacted],

a. Please provide a detailed explanation of the events that led to [redacted]. Where fault was attributed to a specific party, please indicate this clearly in the response.
b. Under the contract [redacted], what recourse or responsibilities did PGE have as a result of [redacted]?
c. What is the estimated additional cost arising from the [redacted]?
d. Please provide the Company's calculation of this value, including an explanation of each input value used.

Response:

[redacted]

[redacted]

PGE’s response to this data request is protected information subject to Protective Order No. 21-206.

September 29, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 778
Dated September 15, 2021

Request:

With regard to the "fuel stock" included in the Company's filing:

a. Please provide a narrative explanation of the purpose of fuel stock.
b. Please provide the value of fuel stock included in the Company's filing in US dollars, including a reference to where this is reflected in the Company's work papers.
c. Please provide a breakdown of the value provided in response to section "b," showing each fuel type separately, providing both the US dollar value of the fuel stock, and its quantity and unit of measure (e.g. gallons or other).
d. Please provide a narrative explanation of how the values provided in response to sections "b" and "c" were calculated. Include a copy of the Company's calculation with this response in electronic workbook format, with all cells and formulas intact.
e. For each fuel price used as an input to the calculation provided in response to section "d," please provide:
    i. The date on which the fuel price was recorded.
    ii. The source from which the fuel price was recorded.
    iii. The unique identifier (reference or ticker) of the fuel price that was recorded.
f. Where fuel stock has been assigned to a specific generator, please provide a breakdown showing:
    i. The fuel types assigned to each generator.
    ii. The quantity of each fuel type (including the unit of measurement) assigned to each generator
    iii. The US dollar value of each fuel type assigned to each generator.
g. If the calculation of fuel stock as included in the Company's filing differs from the calculation of fuel stock recorded on the balance sheet of the Company's SEC 10k filing, please provide a narrative explanation of this difference.
h. If the calculation of fuel stock as included in the Company's filing differs from the calculation of fuel stock recorded on the Company's FERC Form 1 filing, please provide a narrative explanation of this difference.

Response:

a. The purpose of fuel stock is to allow immediate availability of fuels needed to run the Company's generating plants to meet load demand
b. The value of fuel stock included in PGE's filing is $17,367,704. This is included as part of PGE's Operating Materials & Fuel balance, as provided in PGE Exhibit 201. This amount can be isolated in the PGE Exhibit 200 work paper, 2022 "Unbundled ROO Initial," tab "Unbundled" by filtering on accounts 1510001 and 1510002. Please note that due to PGE's method of forecasting these amounts, oil and gas inventories are forecast as one amount and included in account 1510001, while coal and CO2 allowance inventories are forecast as one amount and included in account 1510002.
c. The amounts separated and included in the two accounts above are $8,795,811 for gas and oil inventories and $8,571,894 for coal and CO2 allowance inventories. PGE forecasts these inventories based on dollar amounts.
d. PGE's coal inventory forecast is the actual ending balance,[1] including the cost of CO2 allowance inventory, as of March 31, 2021. No change was made to this amount. For gas and oil,[2] PGE began with the actual balance as of March 31, 2021 and then applied the monthly forecasted average storage balance net change, as calculated in the 2021 Annual Update Tariff (Docket No. UE 377) multiplied against the North Mist storage capacity and a monthly Sumas forward gas price that is updated on a quarterly basis. The value of oil is simply carried forward from actuals. Attachment 778-A provides the calculation logic used.
e. See response to Part (d.).
f. Gas is used for PGE's Port Westward 1, Port Westward 2, and Beaver Plants; oil is used at Colstrip and Beaver; and Coal is used at Colstrip Units 3&4. CO2 allowances are not assigned to a specific generator.
g. The calculation of PGE's actual fuel stock does not differ.
h. The calculation of PGE's actual fuel stock does not differ.

[1] Coal inventory accounts included in actuals are 1510002, 1510003, 1510004, 1510005, 1510006, and 1581001.
[2] Gas and Oil inventory accounts included in actuals are 1510001 and 1510008.

Confidential Staff Exhibit

"Confidential Attachment A to PGE Response to Staff DR 778"

is filed in electronic format only

September 29, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 779
Dated September 15, 2021

Request:

With regard to the Company's historic "fuel stock":

a. Please provide the forecasted value of the Company's fuel stock in each year from 2016 to 2021.
b. Please provide the actual value the Company fuel stock in each year from 2016 to 2020.
c. Please provide a breakdown of the value provided in response to section "a," showing each fuel type separately, providing both the US dollar value of the fuel stock, and its quantity and unit of measure (e.g. gallons or other).
d. Please provide a narrative explanation of how the values provided in response to sections "a" and "b" were calculated. Include a copy of the Company's calculation with this response in electronic workbook format, with all cells and formulas intact.
e. Where fuel stock has been assigned to a specific generator, please provide" a breakdown showing:
    i. The fuel types assigned to each generator.
    ii. The quantity of each fuel type (including the unit of measurement) assigned to each generator
    iii. The US dollar value of each fuel type assigned to each generator.

Response:

a. PGE objects to this request on the basis that it is vague, unduly burdensome, and requires new analysis. Without waiving and notwithstanding this objection, PGE responds as follows:
PGE maintains a rolling forecast of fuel stock that changes monthly based on recorded actuals for the previous month. Additionally, PGE typically reviews, and updates forecast parameters on an annual basis. This forecast is maintained within a logic-based software system and PGE does not maintain historical forecast scenarios beyond a few years. Attachment 779-A provides forecast 2017 and 2018 year-end balances as filed in PGE's last two general rate cases (Docket Nos. UE 319 and UE 335) and a forecast 2021 year-end balance consistent with the forecast used in PGE's current general rate case. Additionally, as PGE did not file a general rate case between UE 335 and UE 394,

Attachment 779-A provides a year-end 2019 forecast balance, based on a March 2019 forecast, with actuals through February 2019 and a year-end 2020 forecast balance, based on a March 2020 forecast, with actuals through February 2020.

b. Attachment 779-B provides actual year-end quantity and value of PGE's fuel stock for 2016 to 2020.

c. PGE forecasts fuel stock based on the value and not based on quantity. See PGE's response to OPUC Data Request No. 778 for additional detail.

d. PGE objects to this request on the basis that it is unduly burdensome and requires new analysis. Without waiving and notwithstanding this objection, PGE responds as follows:

   Values for part (a.) come from PGE's historical general rate case records and from historical forecast information. PGE no longer has the calculations used at that point in time. PGE's response to OPUC Data Request No. 778 provides a narrative explanation and data in support on how PGE currently forecasts fuel inventories. Values for part (b.) come from PGE's accounting records. Inventory values are calculated based on ending balances and the weighted average cost of the commodity at that point in time.

e. All current gas inventories are stored at North Mist, which is used to fuel PGE's Port Westward 1, Port Westward 2, and Beaver plants. All current coal inventory is for Colstrip. Oil inventories are currently used for Colstrip and Beaver. CO2 allowance inventories are not assigned to a specific generator. Attachment 779-B provides the historical breakout of these amounts.

September 29, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 780
Dated September 15, 2021

Request:

Please provide a narrative explanation of how Company determines the most efficient and effective inventory levels for fuel stock. In addition to this response, please provide the following information:

a. Please provide references to any relevant internal policies in response to the question above.
b. Please provide a copy of any relevant internal policies with this response.
c. Please indicate whether the optimal inventory levels depend on the price of the fuel. If yes, please provide an explanation of this.
d. Please explain how the Company accounts for potential supply disruptions when planning its fuel stock.

Response:

PGE maintains adequate fuel stock levels for the primary purpose of helping to facilitate the reliable operations of PGE's generation fleet. A secondary purpose, which pertains to PGE's gas inventories at North Mist, is to facilitate the most economic dispatch of PGE's Port Westward 1, Port Westward 2 and Beaver plants (Westside Thermal Plants).

North Mist, PGE's sole source of gas storage, coupled with 103,305 dekatherms (Dth) of daily Northwest Pipeline transport is the portfolio solution for fueling PGE's Westside Thermal Plants. With a total combined daily demand of approximately 220,000 dth PGE must rely on stored gas to operate these plants at full capacity.

Based on current forward price curve information and to meet reliability needs during heavier usage seasons, North Mist, which has approximately 4,100,000dth of capacity, is intended to be full June 30th and November 30th. If a structural change occurs to the current forward price curve the storage optimization will be adjusted, resulting in a different North Mist inventory level throughout the year. For reliability purposes, North Mist inventory is maintained at a minimum storage level of 1,200,000dth.

As it pertains to PGE’s coal supply, PGE has a coal supply agreement with Westmorland, covering the period of January 1, 2020 through December 31, 2025. The terms of the agreement have a minimum take provision for tons of coal annually and tiered pricing. Coal is delivered directly from the mine to the plant for immediate consumption. Due to the proximity of the plant to the mine, a minimum amount of coal is on site at the plant. To determine the annual quantity of coal that will be utilized, the price of the delivered coal is used to determine the dispatch cost for the plant.

a. Not applicable
b. Not applicable
c. Optimal inventory levels do not depend on the price of fuel. For gas at North Mist, it depends on the value derived from PGE’s gas storage modeling in MONET, coupled with maintaining approximately 1.2 billion cubic feet (BCF), to ensure the Port Westward thermal plant can be dispatched for seven days exclusively on storage gas should a gas pipeline disruption occur. Colstrip is a mine mouth plant.[1] On site a small quantity of coal is on hand to help regulate the volume of coal entering the plant and to manage issues that arise at the plant or at the mine. For example, the plant may go off-line for a few hours or few days and coal from the mine would be held on site to be burned when the plant resumes operation. Conversely if there is an issue with the mine, the coal on hand could be utilized to keep the plant running while the mine issues are resolved. In addition, the on-site coal can be blended with coal coming directly from the mine to ensure that quality meets the standard needed for the units. The coal on hand at the plant can vary from a few days’ supply up to several days’ supply of both units 3 and 4 at full operation. Oil inventory levels are based on the amount required to fuel PGE’s Beaver Plant operations at full load for approximately four to five days during heavy load hours. Oil (diesel) is used at Colstrip to start the units. Typically, Colstrip will store sufficient diesel on site to support three to five starts per year for each unit.
d. See PGE’s response to part (c.).

[1] Colstrip is located directly next to a coal mine.

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 812
Dated September 17, 2021

Request:

When considering its available options, did the Company consider decommissioning the Faraday units?

a. If no, please provide a narrative explanation of why this was not considered, including copies of any relevant analysis which informed the Company in its decision.

b. If yes, please provide a copy of all relevant analysis. Include the Company's calculations of the Net Present Value (NPV) of this option, if calculated at the time of the decision.

Response:

a. No. Decommissioning the Faraday Unit 1-5 project was not considered, since the current Hydro license had approximately 40 years remaining, and the repowering would likely result in a clean, non-emitting energy resource that will support PGE's and Oregon's decarbonization goals and would last well beyond the current license end date.
b. Not applicable.

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 814
Dated September 17, 2021

Request:

Attachment A to the Company's response to Staff DR 588 shows a [redacted] approved by the Board of Directors (BOD) [redacted]. Please provide:

a. Any documentation provided to the BOD in relation to this [redacted], including but not limited to presentations, emails, memos, cost estimates.

b. The minutes of any meeting(s) of the BOD at which the [redacted] was discussed and/or approved.

c. Any communication between PGE and its BOD which relates to this [redacted].

Response:

[redacted]

Attachment 814-A and this response are protected information subject to Protective Order No. 21-206.

Confidential Staff Exhibit

“Confidential Attachment A to PGE Response to Staff DR 814”

is voluminous. The referenced pages 11-15 are included in this section, and remaining pages are filed in electronic format.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 815
Dated September 17, 2021

Request:

The Company's response to Staff DR 592 sections "c" and "d" show a [redacted] resulting from [redacted].

a. Please indicate whether the [redacted] was approved by the Company's BOD, including the date(s) of the meeting(s) at which the [redacted] was discussed or approved.
b. Any documentation provided to the BOD in relation to this [redacted], including but not limited to presentations, emails, memos, cost estimates.
c. The minutes of any meeting(s) of the BOD at which the [redacted] was discussed and/or approved.
d. Any communication between PGE and its BOD which relates to this [redacted].
e. Any communication between the [redacted][3] and
   i. PGE
   ii. PGE's BOD.
f. Any communication between the [redacted][4] and
   i. PGE
   ii. PGE's BOD.

Response:

[redacted]

[redacted]

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 817
Dated September 17, 2021

Request:

The Company's response and attachments to Staff DR 591 detail [redacted] Please:

a. Provide the total amount in US dollars that PGE expects to pay to and/or receive from [redacted]. Further, please:
   i. Show payments made and payments received separately
   ii. Include references to the contract clause and contract version/amendment that determines each payment.
   iii. Specify the contracted completion date, and the most recently forecasted completion date for each milestone for which a payment is due.
b. Indicate whether the total payment shown in response to section "a" is reflected in the Company's filing, providing specific references to where the payments are reflected in the Company's work papers. For any payments not included, please provide an explanation for their exclusion.
c. Indicate whether PGE expects to pay a bonus(es) to the contractor on completion of the project. If yes, please provide a specific reference to the contract clause that determines each payment, and the amount of each payment in US dollars.
d. Please indicate whether the payments listed in response to section "c" are included in the Company's filing. If no amounts are payable, please confirm that no costs relating to contractor bonuses have been included in the Company's filing.

Please provide the requested information in electronic workbook format with all cells and formulas intact.

This is an ongoing request. Please update this response to reflect any change to the forecasted completion, synchronization, or other date.

Response:

[redacted]

[redacted]

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 818
Dated September 17, 2021

Request:

Revision 97[5] to the budgeted cost of the Faraday project [redacted] **. The Company states that “** [redacted] ”[6]

a. Please provide a breakdown of the [redacted], including the US dollar value and a breakdown of each of the items listed in section “a,” parts “i, ii, iii, and iv.

b. For any portion of the [redacted] not represented by the categories listed in section “a,” parts “i, ii, iii, and iv,” please provide an explanation of each expense, and the US dollar value of each.

Please provide the requested information in electronic workbook format with all cells and formulas intact.

Response:

[redacted]

[redacted]

This response is protected information subject to Protective Order No. 21-206.

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 820
Dated September 17, 2021

Request:

PGE's response to Staff DR 592 section "b" states: [redacted]"

Please provide a step by step explanation of the steps undertaken by the Company in response to [redacted]. Please provide this answer in a narrative format including all details of the steps taken, without reference to other sources."

Response:

[redacted]

This response is protected information subject to Protective Order No. 21-206.

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 821
Dated September 17, 2021

Request:

Please provide a narrative explanation of how the [redacted] (following the [redacted]) benefits PGE, or protects PGE from [redacted]. Please provide a response that shows specific comparisons with the [redacted].

Response:

[redacted]

[redacted]

The response to this data request is protected information subject to Protective Order No. 21-206.

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 822
Dated September 17, 2021

Request:

Regarding the forecasted cost of the Faraday repowering:

a. Please specify who forecasted the cost of the Faraday repowering (e.g. PGE or a third-party).
    i. If a third-party, please provide the name of the party, and a brief explanation of their previous and current relationship with PGE.
    ii. If a third-party, please indicate whether PGE has or had [redacted]. Detail any efforts undertaken or planned by PGE in relation to this response.

b. Please provide a narrative explanation of how PGE or the third party [redacted] the cost of this project. Provide detail of how costs were originally forecasted, and how this differs from the [redacted]

c. Please detail any changes that have taken place at PGE (including but not limited to NPV calculations, project planning, cost estimation, and contractor selection) as a result of [redacted].

d. Please indicate whether the forecasted budget in 2016 included a cost "contingency(ies)" or a "buffer(s)" for potentially cost changes.
    i. If yes, please provide detail of the "contingencies" or "buffers" that were included, providing references to where these amounts can be identified in the Company's initial NPV calculation.
    ii. If no, please explain why this was not included.

e. Please indicate whether the current budget for the Faraday project includes a cost "contingency(ies)" or a "buffer(s)" for potentially cost changes.
    a. If yes, please provide detail of the "contingencies" or "buffers" that are included, providing references to where these amounts can be identified in the Company's filing.
    b. If no, please explain why this is not included.

f. Please indicate whether the Company locked-in the costs of materials in advance of the project.

    i. If yes, please provide detail of the costs that were locked-in, and PGE's reasons for doing so. Include references to, and copies of, any relevant contracts or other documentation.
    ii. If no, please explain why this was not done.

Response:

[redacted]

[redacted]

Attachments 822-A, 822-B, and this response are protected information subject to Protective Order No. 21-206.

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 825
Dated September 17, 2021

Request:

Please explain why PGE [redacted].

Response:

[redacted]

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 827
Dated September 17, 2021

Request:

The Company's work paper titled ""2022 Unbundled ROO Initial," tab name "Unbundled," lines 8121 and 8122 shows the following two items:

[redacted]

a. Please confirm or deny that [redacted] fuel stocks included in the Company's filing.
b. If denied at section "a" above. Please provide detail of any other fuel stock included in the Company's filing, giving specific references to where this appears in the Company's filing and/or work papers.
c. Please provide the physical location(s) of the Company's [redacted], including detail of their proximity to the Company's generation stations.
d. For each plant at/adjacent to which fuel stock is held, and which is forecasted to be operational during the 2022 test year, please provide the following information in electronic workbook format:
    i. The quantity of fuel stock held on December 31st of each year from 2015 through 2020.
    ii. The daily fuel consumption of the plant for each day during the period September 1, 2019 to present.

In this response, please ensure that consistent units of measurement are used in the Company's response to each subsection.

Response:

PGE does not consider the above request to be confidential. As such we are providing the response as public.

a. PGE has included a forecast of coal, gas, and oil fuel stocks, along with a forecast of CO2 allowances. PGE's response to OPUC Data Request Nos. 778, 779 and 780 provide additional detail regarding these commodities.
b. See PGE's response to OPUC Data Request Nos. 778, 779, and 780.
c. PGE's oil and coal stocks are located directly at the plants. PGE's gas stock is located at North Mist, which is connected to PGE's Port Westward 1, Port Westward 2, and Beaver plants by an approximately 13-mile pipeline. See PGE's response to OPUC Data Request Nos. 778, 779, and 780 for more detail.
d. PGE objects to this request on the basis that it is unduly burdensome and requires new analysis. Without waiving and notwithstanding this objection, PGE responds as follows:
    i. PGE's response to OPUC Data Request No. 779, Attachment 779-A, provides year-end fuel inventory by plant from 2015 through 2020.
    ii. PGE does not receive or maintain a detailed record of daily fuel consumption for Colstrip. As such, Attachment 827-A provides a calculated daily consumption for Colstrip by using hourly generation multiplied against an approximate tons of coal/MWh conversion factor. Attachment 827-B provides daily gas consumption data for Port Westward 1, Port Westward 2, and Beaver from PGE's PI System database. Attachments 827-A and 827-B are protected information and subject to Protective Order No. 21-206.

October 12, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE *First Supplemental* Response to OPUC Confidential Data Request 827
Dated September 17, 2021

Request:

The Company's work paper titled ""2022 Unbundled ROO Initial," tab name "Unbundled," lines 8121 and 8122 shows the following two items:

[redacted]

a. Please confirm or deny that [redacted] fuel stocks included in the Company's filing.
b. If denied at section "a" above. Please provide detail of any other fuel stock included in the Company's filing, giving specific references to where this appears in the Company's filing and/or work papers.
c. Please provide the physical location(s) of the Company's [redacted], including detail of their proximity to the Company's generation stations.
d. For each plant at/adjacent to which fuel stock is held, and which is forecasted to be operational during the 2022 test year, please provide the following information in electronic workbook format:
    i. The quantity of fuel stock held on December 31st of each year from 2015 through 2020.
    ii. The daily fuel consumption of the plant for each day during the period September 1, 2019 to present.

In this response, please ensure that consistent units of measurement are used in the Company's response to each subsection.

Original Response (dated October 1, 2021):

PGE does not consider the above request to be confidential. As such we are providing the response as public.

a. PGE has included a forecast of coal, gas, and oil fuel stocks, along with a forecast of CO2 allowances. PGE's response to OPUC Data Request Nos. 778, 779 and 780 provide additional detail regarding these commodities.
b. See PGE's response to OPUC Data Request Nos. 778, 779, and 780.
c. PGE's oil and coal stocks are located directly at the plants. PGE's gas stock is located at North Mist, which is connected to PGE's Port Westward 1, Port Westward 2, and Beaver plants by an approximately 13-mile pipeline. See PGE's response to OPUC Data Request Nos. 778, 779, and 780 for more detail.
d. PGE objects to this request on the basis that it is unduly burdensome and requires new analysis. Without waiving and notwithstanding this objection, PGE responds as follows:
    i. PGE's response to OPUC Data Request No. 779, Attachment 779-A, provides year-end fuel inventory by plant from 2015 through 2020.
    ii. PGE does not receive or maintain a detailed record of daily fuel consumption for Colstrip. As such, Attachment 827-A provides a calculated daily consumption for Colstrip by using hourly generation multiplied against an approximate tons of coal/MWh conversion factor. Attachment 827-B provides daily gas consumption data for Port Westward 1, Port Westward 2, and Beaver from PGE's PI System database. Attachments 827-A and 827-B are protected information and subject to Protective Order No. 21-206.

<u>Supplemental Response (dated October 12, 2021):</u>

PGE objects to this request on the basis that it is unduly burdensome and to the extent that it requires new analysis. Without waiving and notwithstanding this objection PGE responds as follows:

Attachment 827-C provides monthly oil consumption at Beaver by unit, for the period of September 2019 through September 2021. PGE is currently unable to provide oil consumption at the site in more granular detail.

PGE does not maintain oil consumption records for Colstrip. However, Attachment 827-C, tab two, provides a calculated monthly consumption amount utilizing PGE's monthly ending balance of oil and monthly deliveries of oil at Colstrip for the period of September 2019 through September 2021.

Attachment 827-C is protected information and subject Protective Order No. 21-206.

Confidential Staff Exhibit

“Confidential Attachment A to PGE Response to Staff DR 827”

is filed in electronic format only

Confidential Staff Exhibit

"Confidential Attachment B to PGE Response to Staff DR 827"

is filed in electronic format only

Confidential Staff Exhibit

“Confidential Attachment C to PGE Response to Staff DR 827”

is filed in electronic format only

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 828
Dated September 17, 2021

Request:

Regarding the Company's fuel stock requirements:

a. Please provide a narrative explanation of any applicable Company policies or procedures, and provide a copy of same.
b. Please specify the number of days/hours of fuel stock that is maintained at each of the Company's generating facilities. Include references to, and a copies of, any applicable policies or procedures which guide this.
c. Please indicate whether the Company has undertaken any cost benefit, risk management, and/or other analyses to inform its fuel stock requirements. If yes, please provide a copy of any such analyses.
d. Please provide a narrative explanation of the change in PGE's fuel stock requirements following the retirement of the Boardman generating facility in 2020. Include comparisons with December 31st fuel stocks held in prioryears.
e. Please provide a narrative explanation of the change in PGE's fuel stock requirements following its entry into the Energy Imbalance Market. Include comparisons with December 31st coal fuel stocks held in prioryears.

Response:

PGE does not consider the above request to be confidential. As such we are providing the response as public.

a. PGE does not have a company policy regarding fuel stock requirements. See PGE's response to OPUC Data Request Nos. 778, 779, and 780 for additional information.
b. See PGE's response to OPUC Data Request Nos. 778, 779, and 780.
c. Not applicable.
d. Colstrip's fuel stock has remined relatively consistent year over year. Beaver's oil stock also remains relatively consistent year over year. North Mist is based on PGE's seasonal injection and withdrawal cycles and consistent with amounts forecast in PGE's net variable power costs. See PGE's response to OPUC Data Request Nos. 778, 779, and 780 for additional information.
e. Entry into the EIM has not affected PGE's fuel stock requirements. See PGE's response to OPUC Data Request Nos. 778, 779, and 780 for additional information.

October 18, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Confidential Data Request 908
Dated October 4, 2021

Request:

Staff notes that a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** which in turn is provided as Confidential Attachment B to PGE's response to Staff DR 591. Please:

a) Indicate whether a risk register had been prepared when the original contract was signed.
b) If yes to section (a), provide a copy of the risk register that was in effect at that time.
c) Please provide copies of every version or update to (including both previous and later versions of) **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** clearly identifying the date of each version or update.

Response:

[redacted]

October 18, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 910
Dated October 4, 2021

Request:

Please provide the Company's actual Fuel Stock on March 31, 2021, and forecasted Fuel Stock on April 1, 2022.

Please provide this information both as a US dollar value, and as a quantity (e.g. tons, barrels, decatherms, or allowances, equivalent to the units expressed in Attachment B to the Company's response to Staff DR 779).

Further, please this information separately for each date, and for each of the following asset types:

a) Oil (diesel)
b) Coal
c) Gas
d) CO2 Allowances

Response:

PGE's forecast fuel stock as of April 1, 2022 is the March 2022 ending balances provided in cells O14 and O17 of PGE's response to OPUC Data Request No. 778, Attachment 778-A.

Attachment 910-A provides PGE's actual fuel stock as of March 31, 2021 by commodity, in dollars and units and is consistent with amounts provided in cells B14 and B17 of PGE's response to OPUC Data Request No. 778, Attachment 778-A.

Please note, as stated in PGE's response to OPUC Data Request Nos. 778 and 779, PGE forecasts oil and gas inventories as one amount and coal and CO2 allowance inventories as one amount and these amounts of fuel stock are forecast based on value and not on quantity.

Staff Exhibit

“Attachment A to PGE Response to Staff DR 910”

is filed in electronic format only

October 18, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 911
Dated October 4, 2021

Request:

Does the Company's use CO2 Allowances solely for compliance with the California Air Resource Board (CARB)? If no, please:

a) Provide a detailed explanation of the Company's other use(s) of CO2 allowances, and

b) Provide a breakdown of the quantity and US dollar value of CO2 Allowances employed by the Company for each use (including CARB compliance), in each year from 2015 to present.

Response:

a) PGE primarily uses CO2 allowances for compliance with CARB. PGE also engages in small transactions of CO2 allowances with counterparties to optimize the CO2 allowances portfolio.
b) Attachment 911-A provides all CO2 allowance transactions between 2015 to present. The transaction list provides detail regarding each transaction, that being a purchase or a sale to a counterparty, or retirement of allowances for CARB compliance.

Attachment 911-A is protected information subject to Protective Order No. 21-206.

Confidential Staff Exhibit

“Confidential Attachment A to PGE Response to Staff DR 911”

is filed in electronic format only

October 18, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 912
Dated October 4, 2021

Request:

With regard to the Company's CO2 Allowance compliance requirement with CARB, please provide:

a) The Company's annual compliance obligation for each year from 2015 to present (e.g. quantity of CO2 Allowances or Offsets required for compliance).
b) The Company's compliance obligation for the 2015 – 2017 compliance period.
c) The Company's compliance obligation for the 2018 – 2020 compliance period.
d) The Company's filing with CARB for each year from 2015 to present, associated with the compliance obligation shown in response to part (a) (e.g. yearly CARB MMR reports).
e) The quantity of CO2 Allowances and Offsets surrendered by the Company in each calendar year from 2015 to present. In this response please include:
   i. The date on which each CO2 Allowance or Offset (or batch of CO2 Allowances or Offsets) was surrendered,
   ii. The compliance year or compliance period against which the CO2 Allowances or Offsets were surrendered.
   iii. In the case of multiple surrenders on the same date, or surrenders including both CO2 Offsets and Allowances, please provide the details of each separately.

Staff requests that the Company provide its most recent filings and estimates for the 2020 calendar year, regardless of the status of this data (e.g. include data pending verification, verified, pending submission, or otherwise).

Response:

a. PGE's annual compliance obligation with CARB between 2015 to present was:
   - 2015: 28,121 metric tons of CO2e
   - 2016: 37,503 metric tons of CO2e
   - 2017: 64,588 metric tons of CO2e
   - 2018: 156,002 metric tons of CO2e
   - 2019: 92,524 metric tons of CO2e
   - 2020: 56,823 metric tons of CO2e

b. PGE's compliance obligation with CARB for the 2015-2017 period was 130,212 metric tons of CO2e.
c. PGE's compliance obligation with CARB for the 2018-2020 period was 305,349 metric tons of CO2e.
d. Attachment 912-A provides the CARB MMR reports the PGE submitted to CARB through the CARB online reporting tool. This response includes the 2020 reporting year, which is final, and verification is complete.
e. PGE's response to OPUC Data Request No. 911 provides all CO2 allowance transactions between 2013 and present, including the allowances and offsets surrendered, the date, and the compliance period.

Attachment 912-A is protected information subject to Protective Order No. 21-206.

October 18, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 914
Dated October 4, 2021

Request:

Staff understands that the Company's EIM GHG benefits are calculated using an EIM GHG revenue forecast, reduced by a forecast of GHG compliance costs.[1]

a) Please provide a copy of the Company's 2022 forecast of EIM GHG benefits in electronic workbook format, with all cells and formulas intact.

b) Please provide a narrative explanation of how the "forecast of GHG compliance costs" is derived, including detail of the source of prices used in this calculation.

Response:

a) Attachment 914-A provides the 2022 EIM GHG revenue forecast included in the October 1, 2021 net variable power cost forecast update in Docket No. UE 391. Please note that the final EIM GHG revenue forecast will be updated in the final NVPC forecast update in Docket No. UE 391 to be submitted on November 15, 2021.

b) PGE's forecast of the GHG compliance cost is based on the ICE forward curve for the 2022 California Carbon Allowance (ICE product code CB0).

PGE's forecast for the 2022 GHG benefit depends on 2019 and 2020 actual results and the Intercontinental Exchange (ICE) forward price curve for the 2022 California Carbon Allowance. The forecast steps include:

- Use GHG award price data ($/MWh) and 2019-2020 weighted average GHG allowance prices ($/mTCO2) to calculate a weighted implied emission factor (mTCO2/MWh).
- Using the weighted implied emission factor, apply the ICE forward price curve for the 2022 California Carbon Allowance (ICE product code CB0), to the implied emission factor to calculate a GHG Award Price ($/MWh).
- Multiply the calculated GHG Award Price ($/MWh) by PGE's 2019-2020 weighted average award quantities to create a GHG revenue forecast. This revenue is reduced by a forecast of GHG compliance costs where applicable (i.e.,

[1] Docket No. UE 391, PGE/100 Vhora-Outama-Batzler/31.

thermal resources assumed to sell GHG in 2022). The price used to calculate GHG compliance cost is adjusted to include California Carbon Offsets (CCOs) used by PGE to comply with California Air Resource Board (CARB) requirements.

Attachment 914-A is protected information subject to Protective Order Nol. 21-206.

Confidential Staff Exhibit

"Confidential Attachment A to PGE Response to Staff DR 914"

is filed in electronic format only

October 19, 2021

To: Kathy Zarate
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 921
Dated October 5, 2021

Request:

With regard to the Company's receipt of coal deliveries at Colstrip, please:

a) Please indicate how frequently coal is delivered to the site. In this response:
   i. Please provide a quantitative measure (e.g. "coal was delivered on 180 days out of 365 days in 2019").
   ii. Please provide a separate answer for each calendar year since January 1, 2018, including 2021 to date.
b) The Company's response to Staff DR 780 states that "if there is an issue with the mine, the coal on hand could be utilized to keep the plant running while the mine issues are resolved." Please:
   i. Indicate whether there were any issues, disruptions, or other interruptions to the mine that affected coal deliveries to Colstrip in the period since January 1, 2015.
   ii. If yes to part (i), please provide a list of each instance in electronic workbook format, including the start and end date of each, a narrative explanation of the circumstances, and its duration in days.
   iii. If no to part (i), indicate whether there were any issues, disruptions, or other interruptions to the mine that affected coal deliveries to Colstrip in the period since January 1, 2010.
   iv. For any issue, disruption, or other interruption identified in response to parts (ii) and (iii) which affected the dispatch of the plant, please provide an explanation of the circumstances, and the duration of the event days.
   v. Please quantify (in tons) the largest and smallest deliveries of coal made to Colstrip in any calendar day during the period from January 1, 2015 to present.
c) What is the maximum capacity of the Company's coal storage at Colstrip? Please provide this response in tons of coal.

Response:

PGE objects to this request on the basis that it is unduly burdensome. Without waiving and notwithstanding this objection PGE responds as follows:

a. The below table provides the approximate days per year coal was delivered to Colstrip Units 3&4 for 2018-2020. Please note this is an estimate based on the number of days Colstrip units 3&4 generated electricity over the same period.

Year	**Delivery Days**
2018	350
2019	360
2020	360

b. To the best of PGE's knowledge, there have been no issues, disruptions, or other interruptions at the mine that affected coal deliveries since January 1, 2015. PGE does not have information prior to 2015 but is unaware of any disruptions since 2010. During the term of the current coal contract, starting January 1, 2020, the highest volume delivered on any calendar day was 35,759 tons.

c. PGE is unable to provide a specific maximum capacity at the site. However, according to the plant operator, there is typically between 15 and 30 days of coal stored on site. This amount will fluctuate depending on several factors including coal quality, owner requested load, and equipment limitations of the plants. Additional factors potentially affecting coal stored on site include contract negotiations, weather conditions, and mine limitations.

October 19, 2021

To: Kathy Zarate
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 925
Dated October 5, 2021

Request:

With regard to the Company's receipt of diesel deliveries at Beaver, please:

a) Please indicate how frequently diesel is delivered to the site. In this response:
   i. Please provide a quantitative measure (e.g. "diesel was delivered on 180 days out of 365 days in 2019").
   ii. Please provide a separate answer for each calendar year since January 1, 2018, including 2021 to date.
b) The Company's response to Staff DR 780 states that "oil inventory levels are based on the amount required to fuel PGE's Beaver Plant operations at full load for approximately four to five days during heavy load hours." Please:
   i. Indicate how the Company chose four to five days as an appropriate amount of time for which stock should be held, including details of analysis performed or other information which informed this decision.
   ii. Please provide copies of any analysis performed or other information which informed this decision detailed in part (i) of this section.
c) With regard to (possible) interruptions to Beaver's diesel supply, please:
   i. Indicate whether there were any issues, disruptions, or other interruptions to deliveries to Beaver in the period since January 1, 2015.
   ii. If yes to section (a), please provide a list of each instance in electronic workbook format, including the start and end date of each, a narrative explanation of the circumstances, and its duration in days.
   iii. If no to section (b), indicate whether there were any issues, disruptions, or other interruptions to deliveries to Beaver in the period since January 1, 2010.
   iv. For any issue, disruption, or other interruption identified in response to parts (ii) and (iii) which affected the dispatch of the plant, please provide an explanation of the circumstances, and the duration of the event days.
   v. Please quantify (in barrels) the largest and smallest deliveries of diesel made to Beaver in any calendar day during the period from January 1, 2015 to present.

Response:

a. PGE objects to this request on the basis that PGE is not tracking the number of days when diesel fuel is delivered because such tracking gives no operational value. Without waiving and notwithstanding this objection, PGE responds as follows:
Diesel fuel is delivered based on inventory requirements. The order may be delivered in one day or over the course of just a few days. However, PGE had diesel fuel delivered at Beaver in only one year since 2015. See below:
   - 2021 - no deliveries year-to-date
   - 2020 - no deliveries.
   - 2019 - 4,905 barrels were delivered (there are 42 gallons per barrel)
   - 2018 - no deliveries.
   - 2017 - no deliveries
   - 2016 - no deliveries
   - 2015 - no deliveries

b. PGE historically held a diesel oil fuel inventory to ensure plant operations for approximately four to five days during heavy load hours in the event of a natural gas disruption or if it is economical to run the plant on diesel fuel. PGE relies on historical plant operations to inform its decision.

c.
   i. There have been no diesel oil fuel supply disruptions or interruptions from 2010 to present.
   ii. Not Applicable.
   iii. See part c.i.
   iv. Not Applicable.
   v. Between 2015 and present there was only one delivery of diesel oil fuel, in 2019. See the response to part a.

October 20, 2021

To: Kathy Zarate
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE *Revised* Response to OPUC Data Request 925
Dated October 5, 2021

Request:

With regard to the Company's receipt of diesel deliveries at Beaver, please:

a) Please indicate how frequently diesel is delivered to the site. In this response:
   i. Please provide a quantitative measure (e.g. "diesel was delivered on 180 days out of 365 days in 2019").
   ii. Please provide a separate answer for each calendar year since January 1, 2018, including 2021 to date.
b) The Company's response to Staff DR 780 states that "oil inventory levels are based on the amount required to fuel PGE's Beaver Plant operations at full load for approximately four to five days during heavy load hours." Please:
   i. Indicate how the Company chose four to five days as an appropriate amount of time for which stock should be held, including details of analysis performed or other information which informed this decision.
   ii. Please provide copies of any analysis performed or other information which informed this decision detailed in part (i) of this section.
c) With regard to (possible) interruptions to Beaver's diesel supply, please:
   i. Indicate whether there were any issues, disruptions, or other interruptions to deliveries to Beaver in the period since January 1, 2015.
   ii. If yes to section (a), please provide a list of each instance in electronic workbook format, including the start and end date of each, a narrative explanation of the circumstances, and its duration in days.
   iii. If no to section (b), indicate whether there were any issues, disruptions, or other interruptions to deliveries to Beaver in the period since January 1, 2010.
   iv. For any issue, disruption, or other interruption identified in response to parts (ii) and (iii) which affected the dispatch of the plant, please provide an explanation of the circumstances, and the duration of the event days.
   v. Please quantify (in barrels) the largest and smallest deliveries of diesel made to Beaver in any calendar day during the period from January 1, 2015 to present.

Original Response (dated October 19, 2021):

a. PGE objects to this request on the basis that PGE is not tracking the number of days when diesel fuel is delivered because such tracking gives no operational value. Without waiving and notwithstanding this objection, PGE responds as follows:
Diesel fuel is delivered based on inventory requirements. The order may be delivered in one day or over the course of just a few days. However, PGE had diesel fuel delivered at Beaver in only one year since 2015. See below:
    2021 - no deliveries year-to-date
    2020 - no deliveries.
    2019 - 4,905 barrels were delivered (there are 42 gallons per barrel)
    2018 - no deliveries.
    2017 - no deliveries
    2016 - no deliveries
    2015 - no deliveries

b. PGE historically held a diesel oil fuel inventory to ensure plant operations for approximately four to five days during heavy load hours in the event of a natural gas disruption or if it is economical to run the plant on diesel fuel. PGE relies on historical plant operations to inform its decision.

c.
   i. There have been no diesel oil fuel supply disruptions or interruptions from 2010 to present.
   ii. Not Applicable.
   iii. See part c.i.
   iv. Not Applicable.
   v. Between 2015 and present there was only one delivery of diesel oil fuel, in 2019. See the response to part a.

Revised Response (dated October 20, 2021):

a. PGE inadvertently stated that PGE had diesel fuel delivered at Beaver in only one year since 2015. Below is a corrected list of diesel fuel deliveries between 2015 and present, including 3031 barrels delivered in 2018:
    2021 - no deliveries year-to-date
    2020 - no deliveries.
    2019 - 4,905 barrels were delivered (there are 42 gallons per barrel)
    2018 - 3,031 barrels were delivered
    2017 - no deliveries
    2016 - no deliveries
    2015 - no deliveries

c.
   v. Between 2015 and present there were only two deliveries of diesel oil fuel, in 2018 and 2019. See the revised response to part a.

October 19, 2021

To: Kathy Zarate
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 926
Dated October 5, 2021

Request:

Please provide a narrative explanation of how the Company's rent payments to 121 Southwest Salmon Corporation are forecasted to change as a result of the Company using its new operations center.

In this response, please:

a) Quantify the number of PGE staff moving their work location to the new operations center, those remaining at the World Trade Center (WTC) location, or other.
b) Describe and quantify any change(s) to PGE's rental needs at the WTC, including details of square feet required. If no change is expected, please provide an explanation for this.
c) Detail the date(s) on which change(s) will take effect.
d) In the requested narrative explanation, please reference the forecasted payments detailed in Attachment A to Company's response to Staff DR 808. Specifically detail whether any change(s) is reflected in 2022 test year forecasted costs, and if not, the date on which change(s) in costs are expected to take effect.

Response:

a. See PGE's response to OPUC Data Request No. 497.

b. PGE is vacating 85,000 square feet, reducing its share of WTC floor space from 67.14% to 48.83%.

c. Move-out has already started and is anticipated to be completed by the end of April 2022.

d. The forecasted payments detailed in PGE's response to OPUC Data Request No. 808 assume PGE has the lower share (i.e., 48.83%) for the entire year, even though actual move-out will not be completed until April 2022.

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 808
Dated September 17, 2021

Request:

Please provide the Company's forecast of payments to its affiliated interests during the 2022 test year. Please provide this information in electronic workbook format with all cells and formulas intact. Further, please:

a. Show payments to each affiliated interest separately.
b. Break the requested data down to show different categories of payments to each affiliated interest separately.
c. For each transaction, indicate whether the Company has forecasted the value of the transaction at the market price, or cost. Note that references to PGE manuals or other documents are not acceptable in lieu of the requested response.
d. For each transaction that the Company has indicated as valued at the market price in response to section "c," please provide a narrative explanation of what market price is used by the Company, including reference to specific sources used.

Response:

Attachment 808-A provides the requested information. All transactions are at cost and as approved by Commission Order No. 18-323 in Docket No. UI 405.

Staff Exhibit

"Attachment A to PGE Response to Staff DR 808"

is filed in electronic format only

October 1, 2021

To: Moya Enright
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 809
Dated September 17, 2021

Request:

Please provide the Company's forecast of costs allocated to its affiliated interests during the test year. Please provide this information in electronic workbook format with all cells and formulas intact. Further, please:

a. Show costs allocated to each affiliated interest separately.
b. Break the requested data down to show different categories of costs allocated to each affiliated interest separately.
c. For each transaction, indicate whether the Company has forecasted the value of the transaction at the market price, or cost. Note that references to PGE manuals or other documents are not acceptable in lieu of the requested response.
d. For each transaction that the Company has indicated as valued at the market price in response to section "c," please provide a narrative explanation of what market price is used by the Company, including reference to specific sources used.

Response:

Attachment 809-A provides the requested information. All transactions are at cost and as approved by Commission Order No. 18-323 in Docket No. UI 405.

Staff Exhibit

“Attachment A to PGE Response to Staff DR 809”

is filed in electronic format only

July 26, 2021

To: William Gehrke
Citizens Utility Board

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to CUB Data Request 006
Dated July 13, 2021

Request:

Refer to OPUC Docket UE 359, Please provide PGE's response to CUB DR 21-23 in UE 359.

Response:

Attachment 006-A provides PGE’s non-confidential response to CUB Data Request Nos. 21-23 in UE 359.

Attachment 006-B provides confidential attachments to PGE’s responses to CUB Data Request Nos. 21-23 in UE 359.

Attachment 006-B is protected information subject to Protective Order No. 21-206.

July 24, 2019

TO: William Gehrke
Oregon Citizens' Utility Board

FROM: Jay Tinker
Directory, Rates & Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 359
PGE's Response to CUB Data Request No. 022
Dated July 17, 2019

Request:

Refer to 2020 AUT – July 15th, 2019 Update Filling- Step 17, please provide a project feasibility study (Kleinschmidt / JR Merit) associated with the Faraday Repower project.

Response:

PGE objects to this request on the basis of relevancy. The costs associated with the Faraday Repower project are not net variable power costs and are not being requested for recovery within UE 359. Subject to and without waiving this objection PGE responds as follows:

Attachment 022-A provides the project feasibility study prepared by Kleinschmidt for PGE in association with the Faraday Repower project.

Attachment 022-A is protected information subject to Protective Order No. 19-112.

Confidential Staff Exhibit

"Confidential Attachment A to PGE response to CUB DR 22 in Docket No. UE 356"

is voluminous, and filed in electronic format only

CASE: UE 394
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Rates, Finance & Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Staff's analysis and recommendations regarding the treatment of non-labor generation O&M; non-labor transmission and distribution O&M; directors and officers insurance and expenses; major maintenance agreements; non-fuel materials and supplies; and miscellaneous deferrals.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. D&O INSURANCE

Q. What is the purpose of Director's and Officer's (D&O) Insurance?

A. D&O Insurance provides liability coverage to company officers and managers to protect them from claims that may arise from the decisions and actions taken within the scope of their duties. D&O Insurance is usually purchased in "layers" to spread risk among different insurers. To acquire adequate coverage limits, diversify exposure, and reduce risk, an insurance structure is assembled where the primary insurer provides specific coverage terms and capacity limits, but less than the total needed. Additional insurers provide supplemental capacity limits that are in addition to the primary layer while still following the basic terms and conditions of the primary layer.

Q. What is PGE's proposal regarding D&O Insurance?

A. PGE proposes to include 50 percent of its total D&O insurance coverage costs in the 2022 Test Year. This proposal is consistent with past Commission practice of disallowing 50 percent of D&O insurance costs in customer rates.

Q. What is the reasoning for the 50 percent disallowance of D&O insurance costs?

A. In Docket No. UE 197, the Commission agreed with Staff that ratepayers and shareholders should share the cost of D&O liability insurance, "[w]e concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost."[1]

In that case, the Commission reasoned that customers who have no say in electing or appointing utility directors or officers should not be held financially responsible for covering 100 percent of the insurance costs. The Commission established this policy to shield customers from liability business decisions or improprieties by management that result in lawsuits. Staff has continued to apply this method of cost sharing in subsequent electric and natural gas utility general rate cases.

Q. Are PGE's D&O costs in the Test Year consistent with Commission precedent?

A. Yes. Therefore, Staff does not recommend any adjustment to the Test Year expense for D&O insurance.

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1 *See* OPUC Order No. 09-020.

ISSUE 2. BOARD OF DIRECTOR'S FEES AND EXPENSE

Q. Please explain the Commission's historical treatment of Board of Director (BOD) Fees.

A. The Commission disallows expense for BOD compensation paid to Company officers. Additionally, some expenses are disallowed, in whole or in part, whether the director is an officer or not. These expenses are for things such as meals and entertainment, incentive pay, e.g. awards, gifts, and non-business related expenses.

Q. Please provide a summary of PGE's proposal for BOD Fees.

A. The Company did not provide any testimony regarding the BOD fees included in the Test Year expense. However, in its response to Staff discovery, PGE provided its 2020 budget and 2021 budgets. For 2020 PGE reports a budget of $1,405,816, and reported actual spending at $1,596,951. Test Year expenses are forecast as $1,553,969, which is a slight decrease over PGE's 2020 spending for BOD expenses.[2] The Company explained that no officer of the Company received BOD compensation, but non-employee directors received BOD cash retainers as well as a grant of restricted stock units (RSUs). For 2020, board members active for the entire year were each granted 2,218 stock units.[3]

Q. Please describe Staff's analysis of the test year BOD fees.

[2] Staff/1102, Moore/1-2. (Company response to Staff DR No. 801).
[3] Staff/1102, Moore/3. (Company response to Staff SDR No. 62).

A. Staff asked the Company to provide actual 2020 costs at the FERC account and transactional level. Staff also requested the 2021 budget and 2022 test year by FERC account. Staff then compared the 2020 actuals to the 2021 budget and 2022 test year. Staff found that the forecasted decrease in expense from the base year actuals to the test year appears reasonable.

Q. What is Staff's recommendation?

A. Staff does not recommend an adjustment to BOD fees. However, an adjustment disallowing a portion of meals and gifts that applies across the Company departments, and may affect BOD expense, is addressed by Staff witness Paul Rossow in Exhibit 1200.

ISSUE 3. GENERATION NON-LABOR O&M

Q. Describe PGE's proposal for Generation Non-Labor O&M expense.

A. Generation non-labor operations and maintenance (O&M) expense reflects the non-labor costs required to perform corrective and preventative maintenance on generation assets, site and equipment management, and health and safety measures. In this filing, PGE forecasts $57.5 million[4] in non-labor generation O&M costs in the test year – an increase of $8.6 million over the 2020 base year expense. This includes expense for operating and maintaining the Colstrip coal plant, gas-fired, hydro and wind plants, and general and miscellaneous expenses.

Q. What explanation does the Company provide for the proposed increase?

A. PGE explains that the main drivers of the cost increases over the 2020 base year are for maintenance of gas and wind plants. Gas-fired plant O&M costs are forecast to increase $6.3 million, and wind plant costs to increase $3.6 million. The cost increase reflects the reduction in normal expense in 2020 due to temporary measures taken in 2020 to "mitigate financial, operational, and safety risks caused by the COVID-19 pandemic.[5] In particular, PGE had deferred certain annual and ongoing maintenance activities at several generation sites "that were deemed lower operational risk for 2020 plant reliability and availability."[6]

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4 Exclusive of major maintenance accrual (MMA) of $11.6 million.
5 See UE 394 PGE/700, Jenkins-Cristea/11.
6 See UE 394 PGE/700, Jenkins-Cristea/12.

Additionally, PGE points to an incremental $2.3 million in O&M costs with the addition of the Wheatridge wind generating facility in the Company's generation fleet.[7]

Q. Describe Staff's analysis of non-labor Generation expense.

A. Staff reviewed Company testimony and work papers, as well as historical expenses for the years 2018-2020. After adjusting those expenses for the removal of the Boardman coal plant[8] Staff finds that PGE's proposed test year expense is below the historical average, and below every other year except for the base year 2020.

	Generation non-labor (millions)				
	2018 - Actual	2019 - Actual	2020 - Actual	2021 - Budget	2022 - forecast
Total	95.2	101.7	78.3	87.1	83.1
minus MMA	-14.3	-17.1	-11.3	-16.2	-11.6
minus Boardman	-8.9	-7.2	-4.1	0	0
	72	77.4	62.9	70.9	71.5

Q. How does PGE explain the reduction in expense relative to historical norms?

A. PGE cites several permanent efficiency measures that were implemented in 2020 resulting in approximately $2.8 million cost reduction for the Test Year forecast.[9] PGE provided a confidential response to Staff discovery on this issue and identified the specific reductions in generation business expense, environmental services expense and maintenance operations.

7 See UE 394 PGE/700, Jenkins-Cristea/15.
8 Boardman coal plant was closed down as of December 31, 2020.
9 See UE 394 PGE/700, Jenkins-Cristea/11.

Q. What is Staff's recommendation regarding non-labor Generation O&M?

A. Staff finds PGE's test year expense to be below historical norms, even with the inclusion of the additional wind generating plant at Wheatridge, suggesting PGE is prudently managing costs in this area. Therefore, Staff does not recommend any adjustment to the Company's Test Year expense.

ISSUE 4. TRANSMISSION AND DISTRIBUTION NON-LABOR O&M

Q. Describe PGE's proposal for Transmission and Distribution (T&D) non-labor O&M expense.

A. In this filing, PGE proposes to include $79 million in non-labor T&D O&M expense in the Test Year revenue requirement. This represents an increase of $10.4 million over actual expenditures in the 2020 base year.[10] These costs cover the operation and maintenance of high-voltage transmission lines, distribution power lines, transformers, substations and communication sites throughout the Company's transmission and distribution system.

Q. What justification does PGE offer to explain the increase in T&D O&M expense?

A. The Company states in its testimony that the primary drivers for the increase in T&D O&M expense are grid modernization, wildfire mitigation, vegetation management, and increases to the Level III storm outage accrual.

The grid modernization projects associated with the Company's new Integrated Operations Center (IOC) accounts for $3.2 million of incremental expense, while its Advanced Distribution Management System (ADMS) accounts for $3.4 million. Wildfire mitigation activities, including vegetation management, increased $4.6 million in the Test Year, as the result of the increasing threat to the T&D system from wildfire.[11]

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[10] See UE 394 PGE/800, Bekkedahl-Jenkins/9.

[11] Further discussion of these projects is found in Staff Exhibit Fox/200 – IOC and ADMS; Sayen/800 – ADMS; Staff Exhibit Dlouhy/600 – Wildfire mitigation; Staff Exhibit St. Brown/1400 – Level III storm accrual.

Q. Describe Staff's analysis of PGE's T&D O&M expense.

A. Staff reviewed the Company's testimony and work papers and reviewed historical expenses from 2018-2020, including transaction detail from 2020. Staff finds that PGE's forecast increased $10.4 million – or 15.1 percent - over the base year actual expense.

Actual	Actual	Actual	Forecast	Forecast		
Dec-18	Dec-19	Dec-20	Dec - 2021	Dec - 2022	2020-2022 Delta	Delta Base Year-Test Year
$44,511,078	$66,432,128	$68,602,340	$65,369,822	$78,973,898	$10,371,558	15.1%

From the above table, it is clear T&D O&M expense has been steadily increasing. From 2018 to 2019, actual costs increased 49.2 percent. PGE's increased spending reflects national trends, according to a report from the U.S. Energy Information Administration. Nationally, operations and maintenance of overhead lines made up the bulk of spending in 2019 for activities such as vegetation management and tree trimming; animal protection; line testing for strength, temperature, voltage and frequency; and storm repairs. According to the report:

> Distribution spending has outpaced growth in both the number of electric customers and in retail electricity sales because much of the increased distribution spending in the last 20 years has been on projects that are not directly related to customer growth or increased sales. These projects include replacing aging equipment, modernizing and upgrading maintenance and billing technology, and fortifying distribution structures against weather-related damage.[12]

[12] *"Major* utilities' *spending on the electric distribution system continues to increase"* – Today in Energy, May 27, 2021 https://www.eia.gov/todayinenergy/detail.php?id=48136

Although PGE has forecast significant incremental expense driven by grid modification, wildfire mitigation, vegetation management and major storm recovery reserves, the Company has found other avenues to offset some of that increase through approximately $15 million in operational reforms and efficiencies.[13]

Q. What is Staff's recommendation regarding T&D O&M?

A. Given the increase in O&M driven by the significant investments in grid modernization and wildfire mitigation, as well as the increased expense related to vegetation management to reduce the threat of wildfire damage to facilities, and the significant offsetting efficiency measures PGE has implemented to offset those increased expenses, Staff finds PGE's proposed test year expense to be reasonable. Accordingly, Staff recommends no adjustment to T&D O&M revenue requirement.

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13 See UE 394 PGE/800, Bekkedahl-Jenkins/10-11.

ISSUE 5. NON-FUEL MATERIALS AND SUPPLIES

Q. Please summarize PGE's proposed rate treatment of non-material fuel and supplies.

A. The Company reports $48.9 million in actual costs for the 2020 base year, and the Test Year is forecast at $50.3 million. This represents a total increase of 2.9 percent over the two-year period.

Q. Please summarize the Commission's historical treatment of non-fuel materials and supplies in rate base.

A. The Commission typically authorizes utilities to include an allowance for non-fuel materials and supplies in rate base.[14]

Q. Please describe Staff's analysis of this issue.

A. Staff reviewed transaction detail from the 2020 base year and reviewed historical balances for non-fuel materials and supplies. Staff finds that while there is a slight increase in the test year forecast over the 2020 base year, the overall balance is below the historical average, suggesting PGE is prudently managing its material and supply inventory.

Non-fuel Mat &Supplies	2017	2018	2019	2020	2021	2022
Total	$54,683,297	$56,020,343	$61,731,628	$48,918,592	$50,355,968	$50,356,000

[14] In the last four rate cases for Avista Utilities, the Commission adopted stipulations that allowed materials and supplies into rate base. See: *In the Matter of Avista Corporation*, UG 246, Order No. 14-015 at 3; In the Matter of Avista Corporation, UG 284, Order No. 15-109 at 3 (April 9, 2015); In the Matter of Avista Corporation, UG 288, Order No. 16-076 at App. A, page 3 (February 29, 2016); and In the Matter of Avista Corporation, UG 325, Order No. 17-344 at 3 (September 13, 2017).

Q. What is Staff's recommendation?

A. Staff recommends no adjustment to the non-fuel material and supply balance included in rate base.

ISSUE 6. MISCELLANEOUS DEFERRALS

Q. Please explain Deferred Accounting

A. When approved by the Commission, deferred accounting allows utilities to track revenues and expenses outside of those collected through base rates and amortize those costs and revenues at a later date.

Q. What is the amount of outstanding deferrals in this case?

A. In total, PGE has approximately $110.7 million in its deferred accounts as of July 31, 2021. This does not include amounts PGE plans to spend in its wildfire mitigation activities that the Company also plans to defer. Of the total, PGE is requesting to amortize $6.5 million into rates in this proceeding.[15] Approximately $2.1 million is deferral of OPUC fee increases over the existing amount in base rates. $4.6 million the Company's Customer Touch Points project. The table below identifies the deferred balances.

[15] Staff 1102, Moore/4 and Staff 1103 excel file. (Company response to Staff DR 756)

	In 2022 Base Rates?	Docket No.	Docket Description	Deferred Balance (as of 7/31/21)
Short duration deferral	Yes	UM 2046	OPUC Fee Deferral	$ 2,057,531.62
	Yes	UM 1948	Cust Touch Points	$ 4,591,660.45
	Yes	UM 1915	MMA Balancing Accounts	$ (8,334,341.56)
	No	UM 2115	Wildfire Emergency	$ 32,069,107.15
	No	UM 2064	COVID 19 Costs Deferral	$ 18,638,382.53
	No	UM 2037	Oregon Corp Activities Tax	$ (747,583.23)
FLP	No	UM 2003	EV Charging Station Deferral	$ 471,480.61
	No	UM 1976	Demand Response Test Bed	$ (3,372,470.03)
	No	UM 1827	Water Heater Pilot	$ (427,565.73)
	No	UM 1708	Residential Demand Response Pilots (ongoing)	$ 191,451.22
	No	UM 1514	Non Residential Demand Response Pilots	$ 478,615.82
Other Pilots	No	UM 2078	Residential Battery Storage Deferral	$ 209,417.25
	No	UM 1938	Transportation Electrification Pilots	$ 715,949.27
Balancing Accounts	No	UM 2131	MSHS Tax Deferral	$ (328,491.02)
	No	UM 1986	MCBIT Balancing Account	$ (576,543.85)
	No	UM 2039	EE Customer Service Balancing Account	$ (167,819.39)
	No	UM 1991	R&D Tax Credits	$ (3,216,934.76)
Deferrals related to ongoing items	No	UM 1988	Qualifying Facilities	$ (3,448,790.61)
	No	UM 1977	Community Solar Costs	$ 1,219,952.75
	No	UM 1789	Environmental Remediation Costs (Portland Harbor)	$ 24,996,399.36
	No	UM 1482	Feed In Tariff / VIR PilotPhotovoltaic Volumetric Incentive	$ (5,720,316.70)
	No	UM 1417	Decoupling SNA Sales Normalization Adj. & Lost Rev I	$ (4,384,830.73)
	No	UM 1301	Direct Access Open Enrollment	$ (180,835.59)
	No	UM 1103	Intervenor Funding	$ 710,910.40
		UM 2156	February 2021 Ice Storm	$ 55,290,764.11
			Total	**$ 110,735,099.34**

Source: From Company response to Staff DR No. 756

Q. Does Staff have a recommendation regarding deferrals?

A. Not at this time. However, Staff invites the Company to discuss in its next round of testimony the outstanding deferrals and discuss options as to how it might mitigate impact of these outstanding balances to ratepayers.

ISSUE 7. MAJOR MAINTENANCE ACCRUAL

Q. What does PGE propose regarding Major Maintenance Accruals (MMAs) in this filing?

A. The MMA mechanism is a balancing account that enables PGE to spread out the cost of major maintenance projects that incur significant cost, but occur infrequently. The MMA expense embedded in customer rates is based on a multi-year forecast of major maintenance projects, with a yearly accrual estimate designed to balance the costs and collections for maintenance projects over multi-year periods. In this filing proposes an additional maintenance project for the 2022 MMA accrual calculation.

Q. What is the new maintenance project included in the MMA?

A. PGE is required to conduct a pipeline integrity assessment every 10 years of its Kelso-Beaver (KB) pipeline to comply with regulations established by the Pipeline and Hazardous Materials Safety Administration.[16] PGE expects to incur approximately $0.72 million in incremental costs in 2022 for this project, and proposes to spread those costs in the MMA over 5 years. The result is an increase to PGE's TY 2022 forecast of $143,000.

Q. What does Staff recommend with regard to the KB pipeline MMA proposal?

A. Staff supports PGE's use of an MMA to spread out the cost of the KB pipeline integrity project, but Staff would recommend the costs be spread over a 10 year period, rather than the 5 year period proposed by PGE. Spreading the

[16] SEE UE 394 PGE/700, Jenkins-Cristea/20

cost over the expected interval of the work to be done would reduce the annual amount in rates and better match the costs vs benefit to ratepayers.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	Mitchell Moore
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem Oregon 97301-3612
EDUCATION:	Bachelor of Arts, Journalism and Political Science University of Hawaii at Manoa (1992)
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division. I have provided expert witness testimony on a number of general rate case dockets, including: UE 294, UE 319, UE 335, UG 288, UG 305, UG 325, UG 344, UG 347, UG 366, and UG 388.

My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints.

Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UE 394
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1102

Exhibits in Support
Of Opening Testimony

October 25, 2021

October 1, 2021

To: Mitchell Moore
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 801
Dated September 17, 2021

Request:

Referring to the Company's responses to OPUC standard data request No. 62 (including attachment A), please supplement the responses and:

a. Include the actual Board of Director Costs for 2020, the allocation to the Oregon regulated operations, and the transactional detail by FERC account and cost element for the 2020 actual Board of Director costs;

b. Provide, by FERC account, the amount of Board of Director costs included in the test year. If the amounts vary from the 2020 budget, please provide a detailed narrative;

c. Identify whether any Board members are also PGE company officers; and whether Board compensation for those officers is included in the test year budget.

d. Provide the breakdown of 2020 "Other Expenses" by cost type and:

   i. Explain whether the expenses and reimbursements for directors includes only the "Offsite Strategic Planning" meeting or does it include other meetings and, if so, describe the frequency, business nature, and location of those meetings;

   ii. Explain whether it includes any amounts for spouse, children, and significant others etc.;

   iii. What portion of the costs are for entertainment versus business?

   iv. Explain whether travel reimbursement includes the cost of using private airplanes. If so, please justify.

   v. Explain where the "Offsite Strategic Planning" meeting was held in 2019 and 2020, and where it is planned to be held in 2021.

Response:

a. PGE Board of Directors' fees and expenses are budgeted and recorded in account 9302004. Account 9302004 also includes Board of Directors' portion of Directors' and Officers' (D&O) Insurance. Attachment 801-A provides transaction level detail consistent with and included in amounts provided in PGE's response to Standard Data

Request No. 057, Attachment 057-B for Board of Directors' fees and expenses, not including D&O liability insurance.

b. The amount included in PGE's test year for Board of Directors' fees and expenses (Account 9302004), excluding D&O insurance,[1] is $1,553,969.99. The increase from PGE's 2020 budget amount results from two primary assumptions. First, PGE has forecast a retainer and Board compensation increase totaling approximately $70,000 compared to 2020 (or approximately 3% annually compared to 2020 budgeted amounts). Second, PGE has forecast an out of state annual offsite meeting for 2022, also resulting in an increase of approximately $70,000 over the 2020 budget. The remaining increase is due to base escalation of other miscellaneous expenses related to the quarterly on-site board meetings forecast for 2022.

c. PGE's CEO, Maria Pope, is the only Board member who is also a PGE Officer. She does not receive compensation for being a PGE Board member.

d. Attachment 801-B provides PGE's 2020 budget for Board of Directors' fees and expenses by cost element. Please note, the final 2020 budget amounts provided in Attachment 801-B differ slightly from amounts provided in PGE's response to OPUC Data Request No. 062, Attachment 062-A. This is because the amounts in Attachment 062-A used the preliminary budget work paper and not the final approved budget provided in Attachment 801-B.

   i. Directors receive reimbursement for booked travel, hotel lodging, and related meals for 4 quarterly meetings, held in Portland, and one annual strategic offsite meeting, which alternates between being held in Oregon and out of state.

   ii. PGE's Board compensation and expenses do not include any amounts for spouses, children, or significant others.

   iii. PGE's budget does not include costs for entertainment.

   iv. PGE does not reimburse Directors for use/cost of private planes.

   v. In 2019, the offsite was held in Palo Alto CA. In 2020 and 2021, the offsite meeting was held virtually due to the COVID-19 pandemic.

[1] PGE included 50% of Board of Directors' D&O Liability Insurance, or $795,954.02, in its test year request.

July 19, 2021

To: Kay Barnes
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Standard Data Request 062
Dated March 10, 2015

Request:

Please provide a breakdown of the costs involved in the director's fees. Are any of these fees paid to directors who are also officers of the Company? Please explain. Also, please explain the type and method for any director compensation paid in stock (i.e., stock awards, stock options, etc.).

Response:

Only non-employee directors of the board may receive cash retainer, meeting, and/or chair fees. Attachment 062-A provides the estimated 2021 Board of Directors forecast and a comparison to the 2020 budget.

Each non-employee director receives a grant of restricted stock units. Each restricted stock unit represents the right to receive one share of common stock at a future date. Provided that the director remains a member of the board, the restricted stock units will vest over a one-year period in equal installments on the last day of each calendar quarter and will be settled exclusively in shares of common stock. Restricted stock units do not have voting rights with respect to the underlying common stock until the units vest and the common stock is issued. For 2020, board members active for the entire year were each granted 2,218 restricted stock units.

October 5, 2021

To: Mitch Moore / John Fox
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 756_Revised
Dated September 22, 2021

Request:

(**REVISED**) Regarding Attachment A (UE 394_OPUC DR 756_Attach A.xlsx), for each deferral listed: (**Note that Attachments are not revised or removed**.)

a. Please provide the balance sheet deferral account number and the related income and expense accounts (accounts as defined in UE 394_OPUC DR 159_Attach A_Revised.xlsx, column A).
b. Please provide the remaining balance, currently approved for amortization, as of September 2021.
c. For deferred amounts not yet subject to amortization:
    i. Please provide the current deferral balance, with and without interest.
    ii. Please provide the expected (estimated or projected) balance as of April 30, 2022, with and without interest.
d. Please identify any deferred balances earning interest at a rate other than the Company's authorized rate of return (AROR).
e. Please identify any deferred balances which will be subject to an interest rate in amortization other than the MBT rate. Reference: https://www.oregon.gov/puc/forms/Forms%20and%20Reports/Modified-Blended-Treasury-MBT.pdf
f. Please provide any additional comments regarding the nature, duration, or suitability for amortization in base rates which the Company believes would enhance the understanding of the parties at this time.

Response:

a. Please see attachment 756-A column K.
b. Please see attachment 756-A column L.
c. Please see attachment 756-A columns M-N.
   Please note, PGE does not forecast Balance Sheet accounts.
d. Please see attachment 756-A column O.
e. Please see attachment 756-A column O.
f. Please see attachment 756-A column P.

CASE: UE 394
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1103

Exhibits in Support
Of Opening Testimony

October 25, 2021

Staff Exhibit 1103

Is

Filed in electronic format

CASE: UE 394
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Paul Rossow. I am a Utility Analyst employed in the Energy Resources and Planning Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1201.

Q. What is the purpose of your testimony?

A. I testify regarding my adjustments to the Company's proposed Test Year expense for certain discretionary spending and membership dues that should not be borne by ratepayers. The proposed adjustments I recommend are derived from review of multiple data responses, analysis of Portland General Electric's (PGE or Company) 2020 Operations and Maintenance (O&M) non-payroll transactions for FERC Accounts 500 through 935, and Commission membership policy.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. MEMBERSHIPS

Q. What is the Company's proposed Test Year expense for memberships in this filing?

A. The Company's Test Year expense for memberships is approximately $3.5 million. PGE did not provide narrative testimony specifically justifying increasing 2020 membership actuals from $2.5 million to a 2022 forecast year of approximately $3.5 million. However, PGE did include memberships as a single line item at UE 394/PGE/400, Ajello – Batzler/2, Table 1 and UE 394/PGE/401, Ajello – Batzler/1. Additionally, PGE included work paper to PGE's Exhibit 400: titled "Corp Support Work paper FINAL", tab titled "Memberships" for membership costs.

Q. What is the Commission's historical treatment of memberships?

A. The Commission has determined that some expense associated with dues or membership fees to various organizations is not appropriately included in a utility's Revenue Requirement, primarily because some or all of the organizational activities are:[1]

- Not necessary for utility service,
- Primarily to promote the company within the community,
- Do not benefit ratepayers, or
- Would not be recoverable in rates if done by the utility itself.

[1] See Order No. 87-406.

Staff follows Commission precedent by recommending recovery of dues or fees paid to:

1. Industry Research Organizations (e.g., Electric Power Research Institute) at 100 percent, except where organizations perform redundant services;
2. National and Regional Industry Trade Organizations (e.g., Edison Electric Industry) at 75 percent, on the basis that certain activities are promotional or lobbying in nature or otherwise do not benefit ratepayers; and
3. Disallowing all fees or dues paid to other types of organizations unless the utility can present a convincing argument that the membership is necessary for utility service or otherwise to benefit ratepayers.

Q. Please explain your analysis for membership costs.

A. Staff analysis included the review of PGE's response to OPUC Standard Data Request No. 90, PGE's confidential response to Standard Data Request number 57 (SDR No. 57), filed on July 19, 2021,[2] PGE's confidential revised response to SDR No. 57, filed on August 27, 2021, PGE's membership worksheet relating to PGE Exhibit 400 work papers to PGE's Exhibit 400: titled "Corp Support Work paper FINAL", tab titled "Memberships", and PGE's response to OPUC Data Request Nos. 340 – 350 and 436 – 438, which relates to memberships. Staff then searched and sorted for memberships by using several column headings titled "Line Description", "Membership Organization",

[2] The data in the Company's confidential response to Staff Data Request No. 57 is too voluminous to include as an exhibit. However, Staff does include membership cost data showing the FERC account totals for each account as Exhibit Staff/1202, Rossow/1.

and "Vendor" provided by the Company in its Attachment 344-A, both responses to SDR No. 57, and PGE's Membership Work paper.

Next, Staff used PGE's 2020 O&M transactional data for the non-payroll costs for each FERC account and escalated to approximate the test year expense by applying the Consumer Price Index (CPI) for Urban Consumers of 4.0 percent and 3.2 percent,[3] respectively, to arrive at the test year adjustment. Staff usually approximates the Company's test year amount for its disallowance by escalating the proposed adjustment with the Company's escalator.

Keeping with Commission policy regarding memberships for organizations in the energy utility industry, Staff recognized the expenses associated with industry research organizations. The Western Electricity Coordinating Council is one such organization.

Staff recognized a disallowance of 25 percent of the expenses associated with national and regional industry organizations on the basis that certain levels of activities of such organizations are lobbying or promotional in nature, or otherwise do not benefit ratepayers. This disallowance represents a sharing of interests between stockholders and ratepayers in these organizations. An example of this type of organization is the Edison Electric Institute, which advocates and promotes the benefits of electricity.

[3] See the Oregon Economic and Revenue Forecast, September 2021, Volume XLI, No. 3, Release Date August 25, 2021.

Q. Did Staff request PGE to provide escalation rates and formulae used to arrive at the 2022 test year for memberships?

A. Yes. Staff issued Data Request No. 341, requesting that PGE include escalation rates and formulae used to arrive at the 2022 test year for memberships. However, PGE did not provide a clear response directly addressing escalation rates and the formulae used to escalate memberships to the 2022 Test Year. However, PGE does indicate in its response to OPUC Data Request 437[4] that the 2022 membership expense forecast was not systematically escalated. Instead, it was adjusted/revised by applicable departments and the PGE Membership department.

Q. What additional information did Staff discover in its investigation of memberships?

A. During Staff's review of PGE's response to Data Request No. 341,[5] Staff saw that PGE's California Independent System Operator (CAISO) membership costs declined in 2020 by $0.6 million and that PGE inadvertently did not include this reduction in its 2021 budget or 2022 forecast.

Q. What additional adjustment is Staff proposing to memberships?

A. Staff is proposing to reduce PGE's CAISO membership cost by $0.6 million.

Q. Why is Staff proposing an adjustment to CAISO costs?

A. Historically, Staff recognizes CAISO costs at 100 percent, and during Staff's review of membership costs, it was revealed in response to Data Request

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4 See Staff/1203, PGE Response to Staff Data Request No. 437.
5 See Staff/1204, PGE Response to Staff Data Request No. 341.

No. 438[6] that certain membership costs appear in Amortization (Cost Element 5406), which is an accounting entry that spreads certain membership costs greater than $150,000 over 12 months of an annual contract or the corresponding months of a multi-year contract. These membership costs are typically paid upfront and are recorded as a prepaid asset on PGE's balance sheet.

Staff invites PGE to show in the Company's next round of testimony how the above described reduction in CAISO dues was fully accounted for to the benefit of ratepayers.

Q. What was the result of Staff's analysis for memberships?

A. Staff's analysis results in a test year decrease to membership costs of $137,037 and a decrease of $0.6 million in CAISO costs, resulting in a total test year membership disallowance of $737,037.

[6] See Staff/1205, PGE Response to Staff Data Request No. 438.

ISSUE 2. MEALS AND ENTERTAINMENT AND MISCELLANEOUS OPERATIONS AND MAINTENANCE EXPENSES

Q. Please explain the Commission's historical treatment of O&M non-payroll discretionary costs.

A. O&M non-payroll discretionary expenses include awards, birthday cards, food, meals, and entertainment. In Docket No. UE 197, the Commission clarified its policy that expenses for meals and entertainment, office refreshments, catering, gifts, and awards are discretionary and should be shared equally by ratepayers and shareholders.[7] Accordingly, a 50 percent sharing of such expenses between customers and shareholders is routinely recommended by Staff. In addition, Staff recommends disallowance of O&M non-payroll expenses that are imprudent or excessive or do not benefit Oregon regulated utility operations at a transactional level.

Q. Did the Company propose an adjustment for meals and entertainment, awards, gifts, and similar discretionary expenditures?

A. In part. Based on the Commission historical treatment, PGE determined a three-year historical average of its meals and entertainment costs comprising of Business Meals and Entertainment (Cost Element 2404), Union Meals and Incidental Expenses (Cost Element 2405), and Salmon Springs Catering (Cost Element 2502), and removed half of that amount from its Test Year expense.

[7] See Order No. 09-020, pp. 20-21.

PGE's adjustment amounts to a $1.0 million reduction to its Test Year expense.[8]

Q. Is the Company's adjustment sufficient to remove an appropriate level of discretionary expenditures from Test Year expense?

A. No, it is not. The Company did not capture all, or an amount that is reasonably close to all, of the sort of discretionary or excessive spending that is the subject of this adjustment. This discretionary spending includes meals and entertainment (M&E), awards, gifts, travel, candy, coffee, flowers, and other similar miscellaneous expenses. Accordingly, the Company's adjustment of 50 percent of expense for what is primarily meals and catering is not adequate.

Q. Please describe Staff's analysis of the company's proposal for O&M non-payroll expenses.

A. Staff began by compiling data provided in the Company's confidential response to SDR No. 57, filed on July 19, 2021. On August 27, 2021, the Company filed a confidential revision to SDR No. 57, which excluded labor-related costs. Excluding payroll transactions, Staff once again began comparing data using both of the Company's confidential responses to SDR No. 57 to review spending in the 2020 base year to ensure proper categorization on the part of the Company. This review provided Staff an understanding of the majority of company spending for each category.

To identify the discretionary expense at issue in this adjustment, Staff first excluded the cost elements reviewed by the Company for its adjustment, which

8 See Staff/1206, PGE Response to Staff Data Request No. 354.

are: Business Meals and Entertainment (Cost Element 2404), Union Meals and Incidental Expenses (Cost Element 2405), and Salmon Springs Catering (Cost Element 2502) to prevent double counting of expenses already captured by the Company. Staff then conducted a keyword search across all remaining cost elements for descriptions and key words related to Airfare, Awards, Entertainment, Gifts, Lodging, Meals, Miscellaneous, and Travel.

To determine whether they should be shared between customers and shareholders according to Commission policy, Staff reviewed the expenses it identified to determine whether they are discretionary and whether the expenses benefit customers..[9] The Commission has historically agreed with Staff that such discretionary expenses are not required to provide safe and adequate service to customers. Additionally, Commission policy does not require ratepayers to support causes that they do not necessarily support.[10]

Staff excluded the expenses that Staff determined had no benefit to customers at 100 percent. Staff disallowed the expenses that Staff determined benefitted both customers and shareholders at 50 percent. Once Staff determined the disallowance based on 2020 base year costs, Staff escalated using CPI's Urban Consumers of 4.0 percent and 3.2 percent, respectively, to

[9] Examples of key words Staff used to search transactions included candy, gum, b-fast, bfast, dessert, party, balloon, bereavement, flower, meal, Christmas, floral, recognition, appreciation, kitchen, food, award, going away, cake, birthday, b-day, snack, coffee, donut, doughnut, bowling, golf, blazer, ball, ticket, prize, gift, dinner, lunch, supper, breakfast, diner, restaurant, napkins, photo, xmas, flight, hotel, airfare, air fare, air, travel, parking, luggage, baggage, shuttle, motel, taxi, lodging, and airport.

[10] See OPUC Order No. 87-406 at 40-41, Order No. 91-186 at 16, and Order No. 09-020 at 20-21.

arrive at the test year adjustment.[11] Staff escalated using the Urban Consumers CPI, which is commonly proposed by Staff for O&M non-payroll expenses.

Q. Would you please explain your adjustments?

A. Staff proposes no further adjustment at this time for meals and catering covered by PGE's adjustment. Staff believes that PGE's $1 million adjustment is adequate to capture 50 percent of this discretionary spending. Instead, Staff's adjustment excludes expense associated with transactions described as: coffee, baby shower, balloons, birthday, party, gift cards, candy, flowers, wine, and Trail Blazer tickets.

Q. What was the result of Staff's review for these cost elements?

A. After exhaustively searching through O&M non-payroll 2020 base year costs, Staff identified $233,692 of expense that should be disallowed at 50 percent and $137,960 of expense that should be disallowed at 100 percent. Escalating these amounts ($116,646 and $137,960) to the 2022 Test Year results in a decrease to the Test Year expense of $273,479.

Q. What is Staff's total test year adjustment?

A. Staff's total test year adjustment is a decrease of $737,037 for memberships and a decrease of $273,479 for other O&M, for a total decrease of $1,010,516.

Q. Does this conclude your testimony?

A. Yes.

[11] The data in the Company's confidential response to Staff Data Request No. 57 is too voluminous to include as an exhibit. However, Staff does include discretionary O&M cost data showing the FERC account totals for each account as Exhibit Staff/1207, Rossow/1.

CASE: UE 394
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	Paul Rossow
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Energy Resources & Planning Division
ADDRESS:	201 High Street SE Suite 100 Salem OR 97302-1166
EDUCATION:	Professional Accounting and Computer Application Diplomas, Trend College of Business 1987
EXPERIENCE:	I have been employed with the Public Utility Commission of Oregon as a Utility Analyst since October of 2002. Current responsibilities include research issues relating to energy utilities. I have actively participated in regulatory proceedings in Oregon, including UE 147, UE 167, UE 170, UE 179, UE 180, UE 197, UE 210, UE 213, UE 215, UE 217, UE 233, UE 246, UE 262, UE 263, UE 283, UE 335, UE 374, UG 152, UG 153, UG 181, UG 186, UG 201, UG 221, UG 246, UG 284, UG 344, UG 347, UG 388, UG 389, and UG 390. I have attended the Utility Rate School sponsored by the Committee on Water of the National Association of Regulatory Utility Commissioners in May of 2005 and the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2005.

CASE: UE 394
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1202

Exhibits in Support
Of Opening Testimony

October 25, 2021

FERC Account No.	FERC Account Description	PGE Costs Before Escalation	Disallowed 2022 Escalated Costs
537	Hydraulic Expenses	$35	$9
557	Other Expenses	$3,394	$709
560	Transmission Operation	$125	$34
567	Rents	$2,303	$618
580	Distribution Operation	$3,603	$967
582	Station Expenses	$4,575	$1,228
588	Miscellaneous Dist. Expenses	$318	$85
593	Maintenance of Overhead Lines	$258	$69
903	Customer Records and Collection	$2,172	$583
908	Customer Assistance	$514	$138
921	Office Supplies	$6,144	$1,649
921	Office Supplies	$63,831	$9,004
923	Outside Services Employed	$13,500	$3,622
925	Injuries and Damages	$723	$194
930.2	Miscellaneous	$2,385,933	$118,128
Total		$2,487,428	$137,037

CASE: UE 394
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1203

Exhibits in Support
Of Opening Testimony

October 25, 2021

August 27, 2021

To: Paul Rossow
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 437
Dated August 13, 2021

Request:

Please expand PGE's membership work sheet to show:

a. The name of the business organization.
b. Highlighted or flagged name of each business membership organization that totals $2.5 for 2020 actuals – showing the calculation in the work paper with all cell references and formulas intact.
c. How PGE developed its budgeted $3.4 million for the 2021 budget, and
d. How PGE escalated its memberships for the 2022 forecast of $3.5 million.

Response:

For items a. and b., see PGE's response to OPUC Data Request No. 344, Attachment 344-A for the requested information.

For item c., PGE developed the 2021 budget by first using the 2020 budget and then incorporating adjustments by individual departments and the PGE Membership department (Dept. 913).

For item d., the 2022 memberships cost forecast was not systematically escalated but rather adjusted/revised by applicable departments and the PGE Membership department (Dept. 913).

CASE: UE 394
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1204

Exhibits in Support
Of Opening Testimony

October 25, 2021

August 20, 2021

To: Paul Rossow
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 341
Dated August 6, 2021

Request:

Please refer to PGE's Standard Data Response No. 090.

a. Please provide a narrative explanation involving escalation from the 2020 membership cost actuals of $2,449,765 to the 2022 test year forecast of $2,851,466.
b. Please include escalation rates and formulae that PGE used to arrive at the 2022 test year for memberships.

Response:

As explained in PGE's response to OPUC Data Request Nos. 347, detail regarding PGE membership costs is found in work papers to PGE Exhibit 400: file "Corp Support Workpaper FINAL", and tab "Memberships". The variance in membership cost between 2020 to 2022 is approximately $1.0 million, which consists of the following:

1. In 2020 only, PGE inadvertently recorded a membership amount of approximately $0.35 million to account 5930001 (distribution maintenance) instead of account 9302001 (Miscellaneous A&G Expense). This cost refers to a portion of Western Electricity Coordinating Council membership costs. Consequently, this cost is correctly included in PGE's test year forecast but only appears as an increase from 2020 to 2022 in account 9302001.
2. North American Energy Standards Board (NAESB) membership increase from 2020 actuals ($0.34 million) to 2022 forecast ($0.44 million), or $0.10 million, which is based on estimates for future periods. PGE periodically trues up its budget estimates to actuals for such membership dues.
3. California Independent System Operator membership costs declined in 2020 by approximately $0.6 million and PGE inadvertently did not include this reduction in the 2021 budget or 2022 forecast.

CASE: UE 394
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1205

Exhibits in Support
Of Opening Testimony

October 25, 2021

August 27, 2021

To: Paul Rossow
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 438
Dated August 13, 2021

Request:

Please refer to work paper titled Corp Supp Work Paper 400, tab titled Memberships. Provide a narrative explanation for including cost element 5406 Amortization with membership costs.

Response:

Membership costs are primarily identified by Cost Element (CE) 2701, Memberships. Certain membership costs, however, appear as CE 5406, Amortization, which is an accounting entry that spreads certain membership expenses greater than $150,000 over 12 months of an annual contract or the corresponding months of a multi-year contract. These membership costs are typically paid upfront and are recorded as a prepaid asset on PGE's balance sheet.

The inclusion of CE 5406, Amortization, is to reflect these accounting entries to amortize pre-paid and/or multi-year memberships that have occurred (i.e., 2018 – 2019) and will occur (i.e., 2021 – 2022).

CASE: UE 394
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1206

Exhibits in Support
Of Opening Testimony

October 25, 2021

August 20, 2021

To: Paul Rossow
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 354
Dated August 6, 2021

Request:

Please refer to PGE's removal of the $1.0 million pertaining to meals and entertainment cost adjustment. Please provide the following information listed below on an Excel spreadsheet.

a. FERC number;
b. Vendor name;
c. Cost element number;
d. Cost element name description;
e. Cost element rollup;
f. Cost element rollup description;
g. Dollar amount for 2020 actuals; and
h. Escalation rate

Response:

a. See PGE's Response to OPUC Data Request No. 351, Attachment A.
b. Attachment 354-A provides transaction level detail, including vendor name, consistent with the accounting string level detail provided in PGE's Response to OPUC Data Request No. 351, Attachment A. Please note, the amounts provided in PGE's Response to OPUC Data Request No. 351, Attachment A differ slightly, as they include co-owner credit amounts applied to PGE's co-owned facilities that have been correctly classified in their respective source Cost Element (CE) categories. However, the transaction-level detail excludes these co-owner credit amounts, as they show up in CE 7001 (Co-Owner Credits) and are not further defined into their respective source CEs.
c. See PGE's Response to OPUC Data Request No. 351, Attachment A.
d. See PGE's Response to OPUC Data Request No. 351, Attachment A.
e. See PGE's Response to OPUC Data Request No. 351, Attachment A.
f. See PGE's Response to OPUC Data Request No. 351, Attachment A.

g. See PGE's Response to OPUC Data Request No. 351, Attachment A.

h. No specific escalation was applied. PGE's adjustment is based on actual amounts. See PGE's Response to OPUC Data Request No. 351 for a narrative description of PGE's adjustment amount.

Attachment 354-A is protected information and subject to Protective Order No. 21-206.

CASE: UE 394
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1207

Exhibits in Support
Of Opening Testimony

October 25, 2021

Row Labels	Sum of Escalated Dosallowed Costs
500	$4.91
506	$23,802.25
513	$19.00
537	$1,225.40
539	$1,664.83
541	$21.91
544	$58.86
546	$503.47
548	$438.78
549	$22,806.83
551	$5.03
553	$800.95
554	$5.55
557	$19,220.59
560	$77.22
561.2	$11.96
570	$11.01
571	$690.63
580	$55,979.09
586	$325.92
587	$4,397.15
588	$2,989.52
593	$2,946.60
903	$19,078.52
908	$13,881.83
921	$93,550.79
924	$61.71
925	$460.76
926	$3,774.24
930.2	$4,635.85
935	$27.54
Grand Total	**$273,478.70**

CASE: UE 394
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1300

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Kathy Zarate. I am a Utility Economist employed in the Rates, Finance, and Audit (RFA) Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1300, Zarate/1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss two issues. The first issue is Portland General Electric's (PGE) loss and/or gains on sales of utility property. The second issue is PGE's test year forecast of Other Revenue.

Q. Do you prepare an exhibit as part of your testimony?

A. Yes, I have prepared the following exhibits:

Exhibit 1301-Witness Qualifications Statement
Exhibit 1302-Company response to Staff data request No. 557
Exhibit 1303-Company confidential response to Staff data request No. 654.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please summarize your recommendations from your testimony.

A. With respect to property sales, I have no expense adjustment. With respect to Other Revenue, I recommend an increase in test year Other Revenue of $8.765 million.

ISSUE 1. LOSSES OR GAINS ON SALES OF UTILITY PROPERTY

Q. Please describe your review regarding gains and losses on utility property sales.

A. I reviewed records relating to PGE's property sales filings requesting approval for property sales, or providing the Commission notice of a property sales transaction. In addition, I conducted phone conferences with PGE regarding this issue. This review included PGE's recent history of property sales filings occurring since 2019 through June 2021.

Q. Please provide some background. What are the statutes regarding the sale of property?

A. The key statute is ORS 757.480. Under that statute, PGE must obtain Commission approval to sell, lease, assign, or otherwise dispose of property valued at $1,000,000 that is necessary or useful in the performance of the public utility's duties to the public.

Q. What about property sales of value less than $1,000,000?

A. For property sales of less than $1,000,000, prior Commission approval is not required; however, the utility provides notice to the Commission that a property sale has taken place for properties of more than $25,000 in value.

Q. What does PGE do with the proceeds or losses from a property sale?

A. PGE places record the gains or losses from each of those sales in its property sales balancing account. The aggregate cumulative sum of gains and losses in the property sales balancing account are deferred and later flowed through to customers via Schedule 105. For example, PGE filed ADV 1206 late last year (2020) to flow through to customers the property sales account balance at that time with a rate credit for service on and after January 1, 2021.

Q. As a result of your property sales review, do you propose any adjustments to PGE's test-year expenditures to account for losses or gain on property sales?

A. No. The property sales conducted since the last rate case have been addressed using the two procedures described above. PGE complied with the approval requirements of ORS 757.480, recorded the gains, totaling $1,782,753, in the property sales account, and obtained approval to amortize the property sales balance in an advice filing filed in December 2020.[1] Accordingly, I have no adjustment at this time.

[1] See Order Nos. 18-440, 19-019, and the Staff Report for ADV 1206 (December 15, 2020 Public Meeting).

ISSUE 2. OTHER REVENUE

Q. Please describe your second issue – Other Revenue.

A. Besides collecting revenue from retail customers using electric power sold by PGE, PGE also provides other services and charges various fees that also produce revenue that contributes toward meeting PGE's revenue requirements. Other Revenue includes, but is not limited to, pole attachment rental revenue, transmission revenue, late payment fees, and rent of electric property. For this rate case, as in prior rate cases, PGE includes a forecast of Other Revenue for the test period.

Other Revenue is a substantive component of a rate case in that Other Revenue are an offset to expenses and reduce overall revenue requirements.

Q. What amount did PGE forecast for this 2022 Test Period for Other Revenue?

A. PGE forecasted Other Revenue in the amount of $29.3 million.[2] In contrast, PGE's actual 2020 Other Revenue was $32.2 million.[3] PGE states that the decrease in Other Revenue between the Base Year and forecasted Test Year is primarily due "to certain revenue being recorded to Other Revenue in 2019 and 2020 that offsets expenses PGE incurred during the same period to provide project support for a third-party accessing PGE equipment."[4] PGE

[2] PGE/200, Tooman-Batzler/9.
[3] PGE/200, Tooman-Batzer/9.
[4] PGE/200, Tooman-Batzer/9.

states that, "because of the temporary and uncertain nature of these costs and revenues, neither have been forecasted for 2022."[5]

Q. How did you go about reviewing this issue?

A. My review included: a) researching recent PGE general rate cases to see what issues of concern were raised; and b) developing alternative projections of test-year Other Revenue. My adjustment reflects the difference between my projection and that forecasted by PGE.

Q. Before discussing your review, could you describe what incentives PGE faces with respect to Other Revenue?

A. Yes. Any regulatory approach gives rise to incentives. With respect to Other Revenue, the incentives appear to be straightforward. PGE benefits to the extent that actual Other Revenue exceeded the forecast adopted by the Commission. PGE is harmed to the extent that actual Other Revenue is below the forecast adopted by the Commission in developing overall revenue requirements.

Q. Could there be other incentives facing the Company other than regulatory incentives?

A. Yes. For example, in budgeting, PGE might seek to use a conservative view for Other Revenue so that it does not face an unexpected lack of revenue needed to fund various PGE programs. That would certainly be understandable. I note that both taking a conservative view of Other Revenue

[5] PGE/200, Tooman-Batzer/9.

and hoping to achieve greater Other Revenue than that adopted in a general rate case are aligned and do not necessarily conflict.

For example, the concept of conservatively forecasting revenues could be viewed as a sound business practice because it could be viewed as imprudent to "spend" revenues that do not pan out. However, for purposes of regulation and setting revenue requirement, a projection of Other Revenue should reflect an expected outcome, not a conservative outcome.

Q. Please Explain.

A. Because revenue requirement should reflect providing the utility an opportunity to earn its authorized rate of return, not a more likely than not opportunity. A conservative approach in forecasting Other Revenue, all else held equal, should provide a more likely than not opportunity to earn the authorized return. Therefore, while for business operations it may be reasonable to take a conservative approach to forecasting, it is not a reasonable basis for determining overall revenue requirement.

Q. Please continue discussing your review of Other Revenue.

A. I reviewed all the Other Revenue components by FERC account. The accounts are listed below:

- 4470003 PGE Transition Services to PGE Merchant
- 4500001 Late Payment charges
- 4510001 Miscellaneous Service Revenues
- 4540001 Rent from Electric Property
- 4540002 Rent from Electric Property-Joint Pole Attachment
- 4560001 Other Electric Revenues
- 4560002 Other Elec Rev-Regulatory Defer Rev
- 4560003 Other Elec Rev-Fish Wildlife Recr. Ops
- 4560012 Other Elec Rev-Steam Sales

- 4561001 Revenue from transmission service to 3rd party customer
- 4561002 Revenue from transmission service to 3rd party customer
- 5660002 Cost for transmission services.

Q. Please briefly describe the FERC accounts.

A. FERC Accounts 4500001 and 4510001 are related with late payment fees, and miscellaneous services revenues are revenues from Schedule 300 in the Company's tariff. This tariff current includes reconnect charges, late payments fees, and fees for returned checks.

FERC Accounts 4540001, 4560001, 4560002, 456000, and 4560012 are related to miscellaneous revenues from various sources as listed above; FERC Accounts 4470003, 4561001, 4561002, and 5660002 are related to transmission revenue; and FERC Account 4540002 is associated with Pole attachment revenue.

Q. You noted above that the Company forecasts a Test-Year amount of $29.3 million, which is a decrease of $2.9 million from the actual Other Revenue recorded in 2020. Does your review support PGE's forecasted amount?

A. No. The table below displays actual Other Revenue total amounts for the time period 2016 through 2020. As you can see, there is a general trend of increasing Other Revenue through 2019. There is a substantive drop-off in Other Revenue in 2020. This drop-off appears to be large part to the effects of COVID-19 as the category of Forfeited Discounts experienced a significant decrease in revenues due to the Commission suspension of disconnections and late payment charges.

	2016	2017	2018	2019	2020
	Amount	**Amount**	**Amount**	**Amount**	**Amount**
Other Revenue Total	$26,154,793	$25,326,933	$31,644,096	$41,172,048	$32,074,214

This contrasts with PGE's 2022 projection of $29.3 million in Other Revenue. That level of Other Revenue has not been experienced since 2017, and is ten percent less than 2020, which was a COVID-19 impacted year.

Q. Did you review PGE's forecasts of Other Revenue and compare those to actual Other Revenue?

A. Yes. I reviewed that last three rate cases: UE 335, UE 319, and UE 294. In each of those rate cases, PGE's forecast for Other Revenue was significantly lower than actual Other Revenue.

In the following table, I display the PGE forecasted revenues, actual revenues, and the percentage that was under forecasted. From that data, I calculate the average under forecasting of revenues and apply that average to the UE 394 PGE forecast.

	2016	2017	2018	2019	2020	2022
	Amount	**Amount**	**Amount**	**Amount**	**Amount**	**Amount**
Other Revenue Total	$26,154,793	$25,326,933	$31,644,096	$41,172,048	$32,074,214	$29,300,000
PGE Forecast	$25,100,000		$25,800,000	$25,300,000		
Percentage of PGE underforecast	-4.2%		-22.7%	-62.7%		
Average percentage of PGE underforecast	-30%					
PGE 2022 Forecast	$29,300,000					
Staff Projection of underforecast amount	$8,749,884.76					
For 2022, UE 394/PGE/200, Tooman-Batzler/9						
For 2019, UE 335/PGE/200, Tooman-Espinoza/6						
For 2018, UE 319/PGE/200, Tooman-Brown/2						
For 2016, UE 294/PGE/200, Tooman-Brown/6						

Q. What does this Staff alternative conclude?

A. PGE under forecasted Other Revenue by 4.2 percent, 22.7 percent and 62.7 percent in general rate cases UE 294, UE 315, and UE 335, respectively. On average, this represents an average under forecast rate of 30 percent. If you apply the 30 percent average to PGE's Other Revenue forecast in this docket that amounts to under forecasting Other Revenue by $8.7 million.

Q. Did you develop a second alternative for a projection of 2022 Other Revenue?

A. Yes. As a second alternative, I developed a forecast of Other Revenue using a three-year moving average approach. This approach means that next year's Other Revenue equals the average of the prior three years' Other Revenues.

Q. Please describe that approach.

A. The second alternative Staff developed uses information provided by PGE in response to Staff Data Request 557, Attachment A. In that response, PGE provided a breakdown of Other Revenue from 2016 through 2020. The Staff alternative and analysis is shown below.

Account	Account Description	2016	2017	2018	2019	2020	2021
4470003	SalesfrResale-IntertiePGEtoPGE	($5,936,822.62)	($6,256,410.14)	($6,946,711.00)	($7,312,967.80)	($7,067,265.15)	($9,167,068.96)
4500001	Forefeited Discounts	($2,994,617.00)	($3,415,326.54)	($6,004,495.44)	($7,533,569.16)	($1,510,490.21)	($1,568,519.90)
4510001	Miscellaneous Service Revenues	($1,852,376.91)	($1,830,778.80)	($1,193,165.49)	($1,918,764.34)	($917,276.05)	($706,771.12)
4540001	Rent From Electric Property	($1,025,318.63)	($1,206,299.22)	($1,714,800.63)	($1,271,845.94)	($1,453,819.60)	($1,708,917.22)
4540002	RentFrElecProperty-Joint Pole	($7,679,162.20)	($6,444,067.79)	($7,374,023.07)	($10,582,480.24)	($12,375,540.10)	($13,477,582.42)
4560001	Other Electric Revenues	($3,648,450.50)	($3,825,497.47)	($4,699,484.46)	($7,581,608.73)	($7,028,841.25)	($7,235,575.82)
4560002	OthElecRev-RegulatoryDeferRev	$517,748.88	$1,809,923.78	$2,075,290.49	$43,062.84	$3,252,694.37	$0.00
4560003	OthElecRev-FishWildlifeRecrOps	($12,385.95)	($11,234.06)	($12,310.59)	($13,829.37)	($16,397.01)	($21,575.94)
4560012	OthElecRev-Steam Sales	($1,480,084.55)	($1,892,217.83)	($2,160,357.87)	($1,874,091.37)	($1,419,239.08)	($2,483,651.28)
4561001	TransRevOthers-Non-Intertie	($2,899,444.20)	($3,557,591.95)	($3,518,555.37)	($3,412,284.50)	($3,659,943.01)	($4,251,707.04)
4561002	TransRevOthers-Intertie	($5,080,702.23)	($4,953,843.15)	($7,042,193.22)	($7,026,636.91)	($6,945,361.91)	($8,041,091.52)
5660002	TransOp-MiscExp-IntertieWhePGE	$5,936,822.62	$6,256,410.14	$6,946,711.00	$7,312,967.80	$7,067,265.15	$9,167,068.96
		($26,154,793.29)	($25,326,933.03)	($31,644,095.65)	($41,172,047.72)	($32,074,213.85)	($39,495,392.26)

Q. Please describe the mechanics of your alternative.

A. In reviewing Attachment A to Staff Data Request No. 557, **Exhibit Staff/1302 Zarate/1.** I noticed that for one category, Forfeited Discounts, the value dropped significantly from 2019 to 2020. On further review, the drop was the result of PGE and OPUC regulatory policies due to COVID-19. PGE no longer charged late fees and no longer disconnected customers for non-payment. According, revenues for late fees and disconnection policies in 2020 should be adjusted when forecasting 2022. I chose to adjust it by setting the 2020 value, for purposes of developing three year moving averages, equal to the average of the preceding three year values. Therefore the 2020 value for Forfeited Discounts becomes $5.6 million instead of the actual $0.9 million.

Using a $5.6 million value for Forfeited Discounts for 2020 results in an Other Revenue value for 2020 of $36.2 million. Having values now for Other

Revenue for 2018, 2019, and 2020, taking the average of those three years generates the 2021 value for Other Revenue of $36.3 million.

Q. How did you derive the 2022 estimate?

A. Using the actual 2019 value, and adjusting (three year moving average) values for 2020 and 2021, I derived a 2022 estimate of Other Revenue of $37.9 million. Given that PGE's forecast of Other Revenue for 2022 is $29.3 million, my adjustment to Other Revenue under this second alternative is $8.6 million.

Q. So what are the results of your two alternatives?

A. Alternative 1 results in an adjustment to Other Revenue, revising it upwards by $8.7 million. Alternative 2 results in an adjustment to Other Revenue, revising it upwards by 8.6 million.

Q. Did you also develop a third alternative?

A. Yes. For alternative 3, I used the information PGE provided in its response to Staff Data Request No. 557 previously referenced. In response, PGE provided partial year values for 2021 as that year has not yet ended. I assumed that data for 2021 is through June. Therefore, to develop values for the calendar year 2021, I assumed that the values provided by PGE for the first half would be the same as the second half. This means that I multiplied the values provided by PGE for 2021 by two.

Q. Did you make any other adjustment to actual revenues reported by PGE to calculate your adjustment?

A. No. Even though I am fairly certain that some of the recorded data from 2021 is influenced/affected by COVID-19 effects on PGE, or regulatory actions by PUC, I wanted to do an alternative that did not adjust any values, other than extending 2021 data to a full year.

Q. How did you develop estimates for 2022?

A. Each subcategory of Other Revenue has historic information beginning in 2016 through 2021. I ran simple separate ordinary-least-squares (OLS) regressions on each of the subcategories using a relationship based on a constant plus a trend term. After running the regression, for each subcategory, I projected one year out meaning for 2022, by adding the estimated constant value to the estimated trend coefficient multiplied by the value for 2022.

Q. What were the results for Alternative 3?

A. Alternative 3 estimated 2022 Other Revenue at a value of $ 38.3 million. The adjustment to PGE's Other Revenue projection then is the difference between PGE's $29.3 million and the $38.3 million, or $9.0 million.

Q. So what do you conclude?

A. My three alternative adjustment values are $8.6 million, $8.7 million, and $9.0 million respectively. While all three estimates are fairly close together, I believe that Other Revenues should be increased by $8.7 million, which is the estimate between my lowest and highest estimate.

Q. Are there any other considerations?

A. Yes, as I mentioned earlier, PGE just entered into a new contractual relationship with Northern Wasco PUD to provide the PUD electric power scheduling services.

Q. Should that be factored into your recommendation on Other Revenue?

A. Yes. The expected revenue for 2022 associated with the Northern Wasco PUD contract should be added to my $8.7 million adjustment to revenue as that is a new source of revenue.

Q. Did you send any data requests to PGE to determine what the expected revenue is for 2022?

A. Yes, Staff Data Request No. 654 asked for that information. PGE's response to Staff Data Request No. 654 is attached as **Exhibit Staff/1303 Zarate/1.** From that response, the expected level of revenues is **[Begin Confidential]** [redacted] **[End Confidential]**.

Q. Do you need to subtract out the costs of providing the scheduling services from the revenue amount to derive the amount of "net" revenues produced by this new agreement?

A. No. PGE states in its response to Staff Data Request No. 654 that the service provided to North Wasco PUD will be by using existing PGE personnel and facilities and my assumption is that these costs are already included in the test-year revenue requirements. Therefore, there are no incremental costs to be subtracted from the PGE projected revenues.

Q. So combining this last matter, what is your recommended adjustment?

A. My recommended expense adjustment is **[Begin Confidential]** [redacted] **[End Confidential]**. This does not include a gross-up factor to convert the expense into a revenue requirement value.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1301

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATION STATEMENT

NAME:	Kathy Zarate
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Arts, Economics Oregon State University, Corvallis, Oregon Bachelor Degree in Law Republic University, Santiago, Chile
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon (OPUC) since April 2016, with my current position being a Utility Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of regulatory issues such as review of affiliated interest filings, property sales applications and rate proposals. I have approximately 10 years of professional experience in contracting and audit review work, including:

I spent six years as a contract specialist for 3 Com, Santiago, Chile, with responsibilities including coordinating and preparing contracts with resellers, reviewing company books and records, coordinating logistics in business, and working as or with anExpert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst.

I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

I have served as a Principal Analyst at the OPUC for the determination of Energy Property Sales (Oregon Revised Statute 757.140) for the past 3 years. In this position, I investigated, analyzed, and calculated energy cost and impact.

<u>I also support work related to power costs,</u> plant, and associated impact on customer rates. I have reviewed, calculated, and analyzed QFs, wheeling, forced outage rates and Scheduled maintenance outages, PURPA, Solar forecast, wind forecast (UE 366).

I has worked on power cost issues in the below representative cases:

1. UE 366 Idaho Power.
2. UE 375 PacifiCorp
3. UE 377 Portland General Electric PGE

I generally conduct case investigation and analysis on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are:

- PacifiCorp
- PGE
- Northwest Natural Gas
- Idaho Power
- Avista Corp
- Cascade Gas

General Rate Cases: I have been a part of almost every energy rate case since I joined the Oregon PUC in 2016. Historically, my review has included, property sales, material and supply, donations, marketing cost. Currently, my review includes property sales and low-income issues. My work is generally represented in the last four General Rate cases, as examples:

- UG 388 NW Natural
- UE 374 Pacificorp
- UG 389 Avista
- UG 390 Cascade

Rulemaking: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

Low-Income: Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 2058.

Auditing, Interest Rate, Affiliated Interest: I audited cost of capital and financial components (IU 437)

CASE: UE 394
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1302

Exhibits in Support
Of Opening Testimony

October 25, 2021

Kathy Zarate
Public Utility Commission of
Oregon

Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 557

Request:

Based on Exhibit UE 394 / PGE / 202 Tooman - Batzler / 1. Please provide a breakdown of other revenues for the calendar years, 2016-2020, and 2021 to date, including the following categories, and expanding as needed:

4470003: SalesfrResale-Intertie PGE to PGE
4500001: Forefeited Discounts
4510001: Miscellaneous Service Revenues
4540001: Rent from Electric Property
4540002: RentFrElecProperty-Joint Pole
4560001: Other Electric Revenues
4560002: OthElecRev-egulatoryDeferRev
4560003: OthElecRev-FishWildlifeRecrOps
4560012: OthElecRev-steam Sales
4561001: TransRevOthers-Non-Intertie
4561002: TransRevOthers-Intertie
5660002: TransOp-MiscExp-IntertieWhePGE

*Please respond in Excel format.

Response:

Attachment 557-A provides the requested information.

CASE: UE 394
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1303

Exhibits in Support
Of Opening Testimony

October 25, 2021

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 654

Request:

Based on Exhibit UE 394 has PGE entered into an agreement to provide scheduling services for Northern Wasco PUD? If yes, please provide the following:

a. A copy of the agreement;
b. A projection of revenues annually from 2022 through 2025 inclusive;
c. A discussion of the PGE facilities and personnel who will be carrying out the services for Northern Wasco PUD;
d. An estimate of the projected allocated costs PGE will incur to provide the services annually from 2022 through 2025 inclusive;
e. A projection of the incremental costs that PGE will incur above the levels projected for the test year in overall revenue requirements to provide the scheduling services; and
f. Please describe why costs are incremental for each type of costs.

Response:

a. [redacted]

b. [redacted]

[redacted]

e. [redacted]

f. [redacted]

[redacted]

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 654

Request:

[redacted]

Original Response (dated September 27, 2021):

a [redacted]

[redacted]

First Supplemental Response (dated October 8, 2021):

[redacted]

[redacted]

PGE's response to OPUC Data Request No. 654, parts b, c, and d:

[redacted]

CASE: UE 394
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Dr. Max St. Brown. I am a Senior Utility Analyst employed in the Utility Strategy & Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1401.

Q. What is the purpose of your testimony?

A. I discuss PGE's proposed changes to its Level III outage accrual mechanism, marginal cost of service study, and rate spread and rate design.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. LEVEL III OUTAGE MECHANISM[1]

Q. What is PGE's the Level III Outage Mechanism?

A. In 2010, the Commission authorized PGE to collect $2 million annually in rates to pay for service restoration following severe outage events, referred to as Level III storms or outages.[2] At least one of the following criteria must be met for an event to be considered Level III outage: (1). impacts at least 50,000 customers; (2) qualifies for Institute of Electrical and Electronics Engineers (IEEE) Major Event Day exclusion; or (3) several substations and feeders are out of service.[3]

The annual amount included in PGE's Test Year is based on a rolling ten-year average of Level III outage costs, adjusted to reflect present value costs. To the extent that amounts collected are not used in a given year, the funds are accrued and used to offset costs related to Level III outages in future years.

In Docket No. UE 319, the Commission approved the parties' stipulation increasing the annual amount recovered in rates from $2 million to $2.6 million based on an updated rolling 10-year average of Level III outage costs from 2007-2016.[4] In Docket No. UE 335, the Commission increased the amount recovered annually for Level III outage costs to $3.8 million, based on an updated ten-year rolling average. In both UE 319 and UE 335, the Commission rejected PGE's request to create a "balancing account," that

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1 PGE refers to the issue as the Level III Outage Accrual.
2 Order No. 10-478 (UE 125).
3 PGE/800, Bekkedahl - Jenkins/60.
4 Order No. 17-511 (UE 319).

would allow PGE to defer costs that exceed those PGE had accrued for Level III outages and offset them against future accruals.

Q. Please describe PGE's requested changes.

A. PGE proposes several changes. PGE proposes to increase the amount recovered in rates for Level III outage events, create a balancing account that would go negative when costs exceed accrued amounts and that would be capped at $12 million.[5] The table below describes PGE's current Level III Outage Mechanism versus PGE's proposal in this general rate filing:

	Current	**PGE Proposed**
Applicability	PGE can argue that very large storms are unrepresentative of the 10-year average and can request a separate deferral.	No change.
Basis of Amount included in Base Rates	A 10-year moving average of actual Level III outage costs are included in rates.	No change.
Amounts	The current 10-year average is $3.7 million per year.	Increase to $10.4 million per year unless the February 2021 ice storm is treated separately.
Amounts "Deferred"	No negative balances allowed.	Both positive and negative balances allowed
Treatment of balance	If PGE's actual outage costs exceed the accumulated balance, then it can draw from its balance until the balance is depleted. The balance cannot go negative, so shareholders pick up the excess.	Allow the accumulated balance to be up to $12 million positive or negative so that amortization increases or refunds rates on a shared basis between customers and shareholders.
Sharing	None, rates are set based on the 10-year moving average.	When the balance meets the +/- $12 million cap, customers pay/receive 90 percent of the excess

5 PGE/800, Bekkedahl – Jenkins/63.

		amount and shareholders cover 10 percent.

PGE also clarifies that it would likely treat cost recovery for Level III events that result in a declared state of emergency different from Level III events that do not. PGE indicates it would likely defer costs related to Level III events that result from a declared state of emergency.

Q. As you note above, PGE has asked to modify its Level III Outage Mechanism in the past. Please summarize the Commission's treatment of PGE's past requests.

A. In UE 319, parties to the docket stipulated to an increase in the amount collected in rates and agreed that the accrual for Level III outages would not be allowed to go negative. The Commission adopted the stipulation. Staff's testimony in that case explains Staff's opposition to PGE's request. Staff witness Marianne Gardner argued that, "as a matter of policy, Staff does not concur with shifting weather-related risk to ratepayers from shareholders. Between rate cases, utilities generally bear the risk of weather impacts on operating and maintaining their systems."[6]

In UE 335, the Commission rejected PGE's proposal to allow the Level III Storm mechanism to have a negative balance describing that the record did not demonstrate that climate change implies greater expected storm change.[7] The Commission invited PGE to justify why a change to the mechanism is

[6] UE 319, Staff Opening Testimony, Staff/400, Gardner/30-31, citing to Order 04-108, 8-11.
[7] UE 335, Order No. 18-464, pages 13-14.

needed via a "foundational analysis" justifying the causation for a need for a change to reflect climate change.[8] The Commission's invitation also asked PGE to explain how more easily recovering storm costs will continue to incentivize the Company to invest in hardening its system.[9]

Q. Please describe PGE's foundational analysis in this general rate case.

A. In response to the Commission's request to justify the causation of the increasing severity of storms, PGE cites the U.S. Global Change Research Program, which "is a federal program mandated by Congress to coordinate federal research and investments in understanding the forces shaping the global environment, both human and natural, and their impacts on society."[10] PGE summarizes "these projections mean that although there might not be greater likelihood of traditional winter snowstorms, there is an increasing likelihood of high wind and rain events plus greater risk of wildfires."[11]

Q. Is greater risk of wildfires relevant to the Level III Storm mechanism?

A. Not necessarily. In 2020, the wildfires that would qualify as Level III events were also declared as states of emergency. PGE has indicated it likely would not seek to recover costs related to such wildfires through the Level III mechanism. Given that PGE may not use the Level III storm mechanism to recover wildfire related costs, it is not clear that the risk of future wildfires is particularly relevant to the design of the mechanism.

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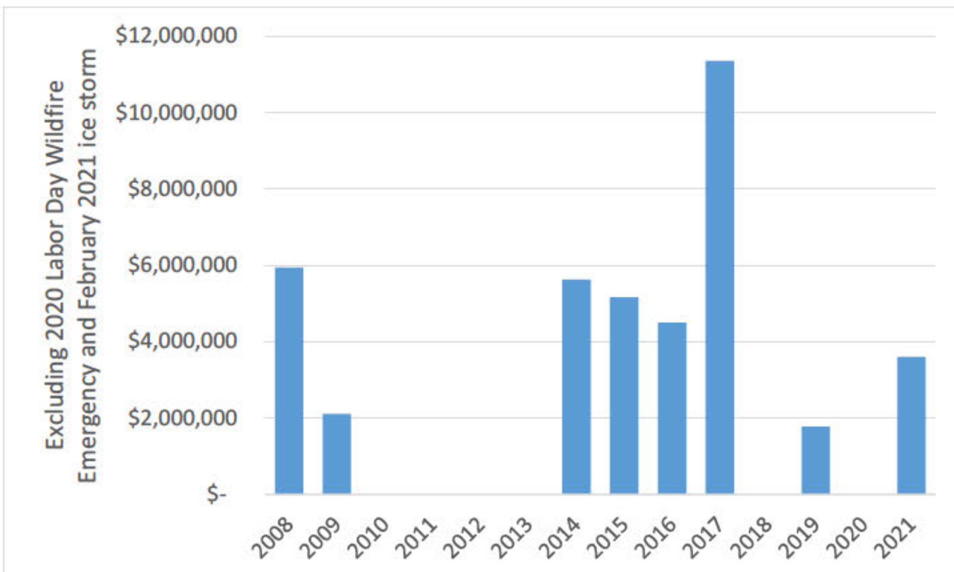
8 Ibid.
9 Ibid.
10 US Global Change Research Program, "About USGCRP" available at: https://www.globalchange.gov/about.
11 PGE/800, Bekkedahl – Jenkins/67.

Q. Does PGE's data show that storms subject to the Level III Outage Mechanism are becoming more severe?

A. No. There are many recent years in which PGE did not incur any Level III outage costs, such as 2010 to 2013. Nor is there a clear upward trend:

Figure 1. Level III Outage Actuals[12]



Q. What statistical test can check for a trend?

A. "The Mann-Kendall Test is used to determine whether a time series has a monotonic upward or downward trend."[13]

Q. What is the result of the Mann-Kendall test on PGE's Level III actuals?

A. The Mann-Kendall statistic for the 14 years of actuals from 2008 to 2021 fails to reject the null hypothesis that there is no trend.[14] This is not surprising since

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[12] PGE/800, Bekkedahl – Jenkins/2 and PGE's response to Staff DR 401.

[13] Zaiontz, Charles, "Mann-Kendall Test," Real Statistics Using Excel, accessed October 14, 2021 at: https://www.real-statistics.com/time-series-analysis/time-series-miscellaneous/mann-kendall-test/.

[14] Staff/1404, St. Brown, Digital Staff Work paper.

year over year the Level III outage restoration costs decrease about as frequently as they increase, whereas if there was an upwards trend, the costs would generally increase year over year.

Q. Does PGE make an argument that Level III outages are becoming more frequent?

A. Yes, in its response to Staff DR 400 PGE asserts that since 2014, it has had 1.75 Level III Storm events per year whereas, from 1979 to 2008, it had 0.48 storm restoration events per year. However, as just shown in *Figure 1* Staff notes that the cost of these storm restorations is not following an upward trend.

Q. Does Staff support PGE's proposal to treat storms with a declared state of emergency outside of the Level III Outage Mechanism?

A. Yes, and in fact per the recent Order No. 21-259 in Docket No. UM 2181, those storms triggered an automatic deferral. Treating the very large storms separately might be in ratepayers favor because the events will be removed from the calculation of the 10-year average used to compute the amount recovered under the Level III outage mechanism. Additionally, the costs incurred relating to state of emergency events would be separately investigated through amortization proceedings.

Q. Did PGE remove the Labor Day 2020 wildfire from the 10-year moving average?

A. Yes.

Q. Did PGE remove the February 2021 ice storm from its calculation of the 10-year rolling average?

A. No. PGE testifies, "PGE has included the February 2021 ice storm, subject to the resolution of PGE's UM 2156 deferral application."[15] However, since PGE and Staff are in agreement that costs associated with storms for which the Governor declared a state of emergency should be treated differently, the February 2021 ice storm should be removed from the 10-year average.

Q. What is the new 10-year rolling average when the February 2021 ice storm is removed?

A. Staff removed the $67.9 million of ice storm costs from PGE/800, Bekkedahl – Jenkins/68, line 12 and recomputed the 10-year average in Staff Exhibit 1402. The new 10-year average is $3.5 million, which is in fact lower than the amount PGE is currently recovering, $3.7 million. Therefore, Staff recommends rejecting PGE's proposal to increase the amount recovered in rates by $6.6 million. Compared to PGE's proposed annual accrual of $10.4 million, Staff recommends a $6.9 million downwards adjustment to $3.5 million.[16]

Q. You've shown that PGE's 10-year average of costs fails to reject the Mann-Kendall null hypothesis of no upwards trend, so a major overhaul of the Level III Storms mechanism to address climate change does not appear to be needed. However, PGE argues that the one-sidedness is unfair, how do you respond?

A. PGE once again asks for a balancing account in which the balance can go negative. PGE proposes to cap the account at $12 million so shareholders do

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15 PGE/800, Bekkedahl – Jenkins/63, lines 9-10.
16 $6.919 million is computed as $10.445 million minus $3.526 million.

not pick up all costs when the actual storm restoration costs exceed the 10-year average set in rates. PGE testifies that "PGE continues to believe that Level III restoration costs are prudently incurred to support public safety and welfare, and to meet customers' increasing reliability expectations, and they should be recoverable… the current mechanism… is notably asymmetrical with respect to risk and reward for PGE shareholders."[17]

Staff appreciates the Company calling out in its testimony that in past rate cases stakeholders have noted the beneficial incentive for PGE to harden its system to avoid actual Level III events costs in excess of the 10-year average. Staff can support changes that both maintain this incentive and help the Company with cost recovery. Therefore, Staff proposes to introduce an annual update to the 10-year moving average instead of just updating the 10-year moving average only in rate cases. Staff believes this change would address the concern that the accrual account will not be sufficient to cover PGE's costs should there be more frequent storms.

Q. Please summarize Staff's Level III Outage Mechanism recommendations.

A. Staff recommends decreasing the Company's 10-year moving average annual accrual from PGE's proposed $10.4 million to $3.5 million and allowing PGE to recover that amount in a separate tariff rider. The February 2021 ice storm should be treated separately (in UM 2156). Staff recommends rejecting PGE's proposal to let the Level III Storms balancing account go negative. Instead, to help PGE better recover costs in an environment of increasing frequency of

[17] PGE/800, Bekkedahl – Jenkins/69.

storms, Staff proposes to update the 10-year average annually. The ten-year average would be calculated using outage recovery amounts incurred on a calendar-year basis. The Company would make a filing each March proposing the new ten-year average and the separate tariff rate would have an effective date of May 1, of each year. The first of these tariff updates would occur May 1, 2023.

ISSUE 2. MARGINAL COST OF SERVICE, RATE SPREAD AND RATE DESIGN

Q. Please describe the purpose of PGE's marginal cost study.

A. Since 1974, the Commission has used marginal costs as one of the principal factors for spreading revenue requirement among customer classes.[18] PGE explains that its marginal study results in "unit costs, expressed as costs per customer, costs per kilowatt (kW) of demand, or costs per kilowatt hour (kWh) are then used to allocate the functional revenue requirements."[19] The marginal cost methodology is needed because book values do not have a comparable basis of depreciation and differ from replacement costs – thus book values would not clearly indicate which schedules are more costly to serve.

In 1998, the Commission adopted a stipulation under which the marginal costs and revenue requirement should be separated into generation, transmission, and distribution components and then reconciled on a functional basis to calculate class revenue requirement responsibility.[20] Accordingly, PGE computes the incremental cost of replacing each major category of its system.

Q. Is Oregon's move to 100 percent clean energy affecting PGE's marginal cost study?

A. Staff asked the Company to consider the appropriateness of a combustion turbine as the proxy resource in light of HB 2021. Any change to the proxy resource might increase the cost of capacity. At this time PGE has not made

[18] Order No. 74-568.
[19] PGE/1100, Macfarlane-Pleasant/1, lines 17-19.
[20] Order No. 98-374.

any changes to its proxy resource type, describing in response to Staff DR 225 that "due to the timing of the newly passed legislation, PGE was unable to factor [HB 2021] into its generation marginal cost study for this general rate case." Staff would like to see the marginal cost study be updated for HB 2021 in a future rate case. In the future, this change might be significant because in general increasing the cost of capacity would spread rates from industrial customers onto smaller customers.

PGE also does not model a carbon tax; doing so would likely increase the cost of energy. In general, increasing the cost of energy would spread rates from smaller customers onto industrial customers.

Q. Please summarize Staff's proposed rate spread?

A. Staff's proposed rate spread versus PGE's proposed rate spread is:

Table 1. Staff versus PGE rate spread

Estimated Cost of Service Base Rate Impacts Inclusive of Schedules 122, and 125, and 146, cycle basis, May 1, 2022		
Schedule	**PGE**	**Staff**
Schedule 7 Residential	6.4%	5.8%
Schedule 32 Small Nonresidential	7.8%	7.8%
Schedule 83 31-200 kW	4.4%	4.9%
Schedule 85 201-4,000 kW	0.0%	0.1%
Schedule 89 Over 4,000 kW	0.0%	0.6%
Schedule 90 30 MWa	-3.2%	0.0%
COS & DA Overall	3.9%	3.9%

Schedules 83, 85, 89, and 90 are all for non-residential customers. The values in Table 1 are shown in Exhibit 1403, page 1.

Q. Please summarize Staff's recommended marginal cost study revisions that affect PGE's rate spread.

A. Staff recommends:

1. Reduce the reserve margin from 12 to 10 percent;
2. Net out energy sales to reduce the cost of capacity;
3. Re-adopt CUB's UE 335 recommendation to allocate 10 percent of smart grid costs to generation; and
4. Incorporate the updated (higher) natural gas prices.

Q. The reserve margin was an issue of contention in UE 335, please describe.

A. In UE 335 Staff opposed PGE's generation reserve margin because Staff did not want to spread rates based on a target number that might not actually be necessary.[21] Staff proposed a ten percent reserve margin instead of the Company's 17 percent and the resolution was a stipulated 12 percent margin for 2019, which PGE used in the current rate case.[22]

Q. Does Staff support a 12 percent reserve margin?

A. No, resource adequacy efforts are anticipated to create efficiency gains in the reserve required to be held by each utility. Staff instead used a 10 percent reserve margin.

Q. What is the impact of reducing the reserve margin from 12 to 10 percent?

A. The lower reserve margin decreases the cost of capacity, and in general will spread rates from relatively more peaky residential and small commercial schedules onto less peaky industrial schedules. In Exhibit 1403, page 2 the

[21] UE 335, Staff/900, Compton/3.
[22] UE 335, Third Partial Stipulation, page 5.

price of capacity fell from $87.50 to $80.60 based on this adjustment of lowering the reserve margin and Staff's next adjustment of netting out energy sale revenues (which also lowers the price of capacity).

Q. In Docket No. UM 2011, Staff hired the consultant Energy and Environmental Economics (E3) to make recommendations for capacity value best practices. Can those learnings be applied in this rate case?

A Yes, in response to Staff DR 646, PGE recalculated its marginal cost study after netting out the energy sales and other revenue from a simple cycle combustion turbine (SCCT) plant. This lowered the cost of capacity by 6 percent (from $87.50 to $82.07/kW-year) and Staff includes this adjustment in Exhibit 1403, page 2 where the price of capacity is reduced to $80.60.

Q. Part of CUB's marginal cost and rate spread arguments in UE 335 and UE 319,[23] were related to the difficulty of spreading the costs of assets used for multiple purposes. How is PGE spreading the costs of its Integrated Operation Center (IOC), which spans multiple cost categories?

A. In response to Staff DR 844, PGE describes that "for the IOC, PGE allocated its cost based on the 2022 labor forecasted to occupy it." For example, 31.6 percent of the $25 million IOC project is allocated to generation.

Q. Is Staff supportive of any of CUB's UE 335 arguments to reallocate costs?

[23] "AMI meters allow for demand response programs, information-driven energy savings, improved distribution asset utilization, and improved outage management. CUB recommends that these be reclassified as 50% customer related, 25% capacity related, 12.5 % energy related, and 12.5% design demand related." (UE 319/CUB/100, Jenks/19-20).

A. Yes, in the UE 335 general rate case, CUB's opening testimony provided a compelling example: "assume PGE is projecting itself to be short of capacity to meet peak summer load. It can address that issue by increasing capacity or by reducing peak load. A capacity increase would include building a single cycle gas plant. Reducing peak load could happen through a demand response program… these two options serve the same need but have radically different cost allocations … Industrial customers would pay 13% of the cost of a peaker, but are allocated only 2/100ths of 1% of the cost of billing costs."[24]

Q. What was CUB's UE 335 recommendation for the spread of smart grid investments?

A. CUB recommended that "the Commission require PGE to hire a third party consultant. A third-party consultant would conduct a review of current and future smart grid investments, functions, and benefits. The third party would also identify possible cost allocation approaches, based on those uses and functions, while following principles of cost causation by rate class."[25]

Q. In UE 394, did PGE perform this study?

A. No. In response to Staff DR 845, PGE describes that for smart grid investments, such as AMI meters, not in distribution or general and intangible plant, "PGE does not otherwise maintain a category of assets identified as Smart Grid for separate functionalization." Although the UE 335 stipulation reallocated some smart grid costs to generation based on CUB's arguments, in

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[24] UE 335/CUB/200, Gehrke-Jenks/3-5.
[25] UE 335/CUB/200, Gehrke-Jenks/11-12.

this general rate case PGE did not repeat that stipulation so in general smart grid costs are not allocated to generation.

Q. How did Staff allocate smart grid costs in UE 394?

A. Staff supports CUB's proposal for a third-party study on how to allocate smart grid costs. For now, Staff approximated the settlement reached in UE 335. Specifically, the third partial stipulation in UE 335 stated that, "PGE will revise its functionalization of the Customer Touchpoints project to allocate 10% of the costs to generation based on the detail provided in CUB Exhibit 200 (UE 335/CUB/200, pages 3 – 9)."[26] "The Customer Touchpoints project refers to the replacement of PGE's CIS [Customer Information System] and MDMS [Meter Data Management System]."[27] The Touchpoints project was $140 million, accordingly, in Exhibit 1403, page 3, Staff approximated moving $14 million (10 percent) worth of gross plant into production by adjusting the production functionalization upwards by $10 million and reducing distribution, billing, metering, and consumer by the same ratios as in UE 335. The $10 million is a rough approximation of the impact of tax and other factors.

Q. What impact does spreading 10 percent of the smart grid CIS and MDMS costs based on generation instead of per customer have?

A. In the UE 335 general rate case, this and other factors decreased the proportion of revenue requirement functionalized to consumer by about five percent and

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[26] UE 335, Third partial stipulation between PGE, Staff, AWEC, Kroger, and Walmart, September 6, 2018, available at: https://edocs.puc.state.or.us/efdocs/HAR/ue335har165958.pdf.

[27] UE 335 / PGE / 900 Stathis – Dillin / 11, lines 19-20.

increased the spread to production slightly.[28] As CUB described, the result of spreading revenue requirement by energy instead of by consumer decreases residential rates.

Q. Does Staff recommend any other updates?

A. Yes. In PGE's response to Staff DR 224, forecasted natural gas prices have increased since the rate case was filed. Because this change is significant, Staff used the updated values in Staff's marginal cost study adjustments. Exhibit 1403, page 4 shows the impact of Staff's use of higher natural gas prices on the energy marginal cost portion of Staff's revisions to the marginal cost study.

Q. Staff has proposed to adjust the marginal cost study by decreasing the cost of capacity, functionalizing additional costs to energy, and updating the cost of natural gas – and then feeding those adjustments into the rate spread, does Staff have any other rate spread revisions?

A. Yes. Staff proposes to revise PGE's Customer Impact Offset (CIO). The CIO is a mechanism that represents departures from strict cost-of-service allocations; it is designed to achieve greater rates simplicity, comprehension, and acceptability and to mitigate the effects of cost-justified increases that greatly exceed the system overall average increase.[29] Starting from the rates implied by the marginal cost study, the CIO can be used

[28] The five percent decrease is the 3.47% ($64,762/$1,867,397 from UE 335 / PGE / 1304 Macfarlane - Goodspeed /1) assigned to consumer in PGE's opening testimony versus the 3.30% ($59,799/$1,811,554 from PGE's December 18, 2018 compliance filing work papers).

[29] Order No. 14-422, p. 11.

to adjust the rate spread. In PGE's proposed CIO, the main subsidy is from non-residential Schedules 85 and 89 to residential Schedule 7 and small commercial Schedule 32.

RATE DESIGN AND PRICING

Q. What is Staff's proposed revision to the CIO?

A. Staff recommends no rate decrease for Schedule 90. In past rate cases the Commission has supported no rate decreases for some schedules while rate increase for other schedules. Although Schedule 90 is in a similar position as Schedule 85 in that its current revenues exceed those implied by the marginal cost study, customers in this schedule do not make a subsidy payment. Further, in at least the last two rate cases, PGE has proposed to move some of the Schedule 90 costs onto Schedule 89 very large non-residential. Although PGE states that Schedule 90 is not an economic development rate for a single customer, Staff would like to see a consistent treatment for the CIO.[30] Exhibit 1403, page 5 shows Staff's adjustment to the CIO so that Schedule 90 has no rate increase by becoming a CIO subsidizer, the total CIO amount is held constant, and Schedules 85 and 89 have an equal percentage decrease in their CIO payments.

Q. Please summarize PGE's rate design proposals?

A. Flattening of residential rates: PGE proposes to reduce the residential rate design blocking, "we propose to reduce the energy charge blocking differential from 7.22 mills per kWh to 3.60 mills per kWh … the full removal of the

[30] PGE/1200, Macfarlane-Tang/16.

blocking would take place in PGE's next general rate case."[31] PGE argues removing the blocking helps high usage customers such as EV owners. PGE argues low-income customers are not harmed because "low income does not simply translate into low usage. On the contrary, low-income customers tend to use more energy and are subject to the higher block pricing than non-low-income customers due to the consumption pattern and dwelling characteristics."[32]

Separate pricing for multifamily residential: Very similar to PacifiCorp's most recent UE 374 general rate case, PGE proposes to decrease the multi-family residential basic charge and increase the single-family basic charge. The marginal cost study supports a difference between the two schedules since there is less feeder cost for multi-family.

Demand charges for commercial: A requirement of UE 335 was that PGE add demand charges to its 31 kW – 200 kW and 201 kW – 4,000 kW rate schedules or describe why it did not add a demand change. PGE describes that it did not add a demand charge because it believes that direct access customers are getting an unfair good deal and this is to be addressed in UM 2143.[33]

Decrease the size cap for Schedule 90: "Currently, Schedule 90 is for customers whose Facility Capacity Exceeds 4,000 kW and whose aggregate energy consumption exceeds 100 MWa. We propose to adjust the eligibility

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31 Id, page 19.
32 Id, page 20.
33 Id, page 4.

down to an aggregate consumption of 30 MWa and include two sets of energy charge prices differentiated at 250 MWa. The purpose of this differentiation is to recognize the load stability value of the energy of mega-sized customers for improved cost allocation … PGE's largest customer is currently the only customer on Schedule 90."[34]

Q. What is Staff's recommendation for flattening of residential rates?

A. PGE flattened its residential rates in UE 335 and PAC flattened its residential rates in UE 374. PGE's *Table 3* argues that increasing rates for low usage customers does not necessarily harm low-income customers:

Table 2: reproduction of PGE Table 3[35]

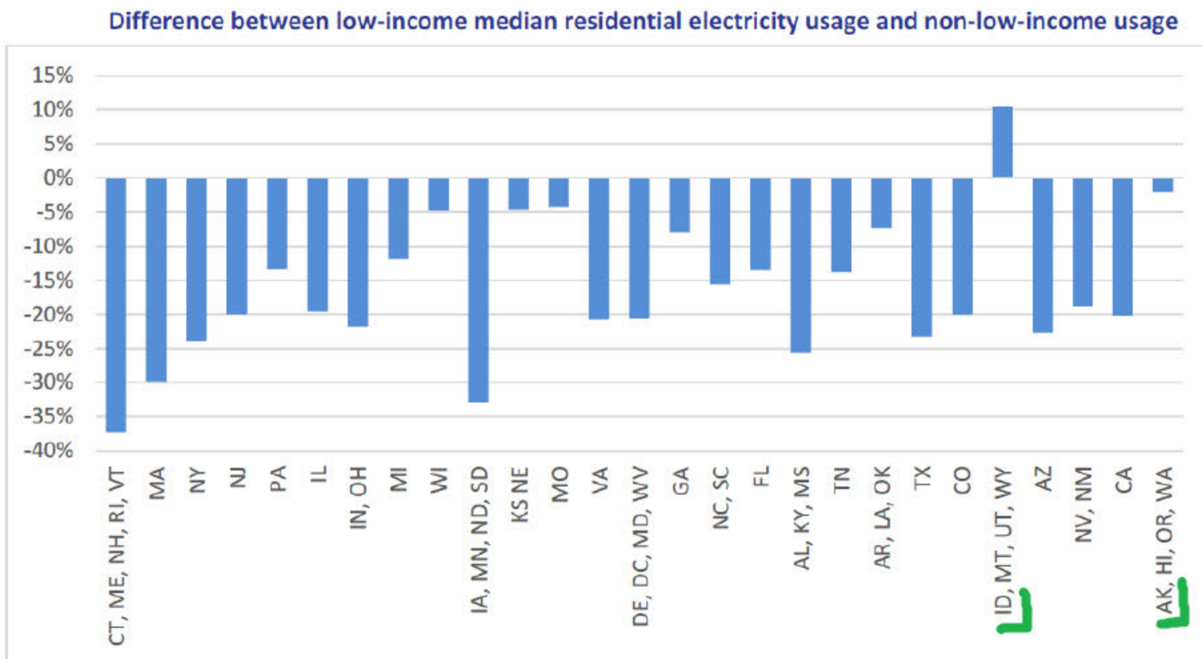
Customer Usage Profile in 2020

2020 Actuals	% of Total Customers Counts	% of Total Customers Usage > 1000 kWh	% of Total Customers Usage > 1000 kWh in Winter (November to April)
Low Income	14%	28.3%	36.9%
Non-Low Income	86%	26.7%	31.7%

Generally, Staff is suspicious of this idea since low-income customers on average nationally have lower usage.[36] However, the Pacific Northwest appears to be unique from the rest of the country:

34 Id, pages 14-15.
35 Id, page 20.
36 "Low-income customers are disproportionately affected by increased fixed charges, as they tend to be low-usage customers." (Synapse Energy Economics Inc., Melissa Whited, Tim Woolf, and Joseph Daniel, "Caught in a Fix: The Problem with Fixed Charges for Electricity," Prepared for Consumers Union, February 9, 2016, available at: https://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf).

Figure 2: reproduction of Synapse Energy Economics 2016 page 15[37]



Source: Energy Information Administration Residential Energy Consumption Survey, 2009. http://www.eia.gov/consumption/residential/data/2009. Developed with assistance from John Howat, Senior Policy Analyst, NCLC.

Using PGE's response to Staff DR 516, Staff analyzed whether PGE's *Table 3* (reproduced as Staff *Table 2*) result that low-income customers do not necessarily use less energy, despite the national finding to the opposite, is driven by winter heating. Here the results are mixed, for PGE's entire dataset subset by customers without electric space heating, low-income customers use more energy than non-low-income customers:[38]

37 Id, page 15.

38 Note that PGE removed very lower and very high electricity usage data points from its data response. Staff has requested a dataset that is not truncated.

Table 3: electricity usage by income and space heating status[39]

	2019 – 2020 monthly electricity usage by customers with non-electric space heating
Low-income	760 kWh
Non-low-income	748 kWh

This is a surprising result for Staff since typically electricity is a "normal good," a product that has increased demand as income rises. It does still appear to be the case that larger users of electricity are more likely to be non-low-income:

Table 4: proportion of customers with high electricity usage by income status[40]

	2019 – 2020 proportion of customers with monthly usage exceeding 2,000 kWh
Low-income	2.3%
Non-low-income	2.9%

It is noteworthy that the opposite result of Table 1 is found in PGE's load research group (where 751 kWh > 688 kWh):

Table 5: electricity usage by income and space heating status for PGE's load research group[41]

	Load research group monthly electricity usage by customers with non-electric space heating	Customer count
Low-income	688 kWh	79
Non-low-income	751 kWh	659

In summary, Staff is hesitant to use the findings from PGE's load research group over the analysis of all customers because the sample size customer

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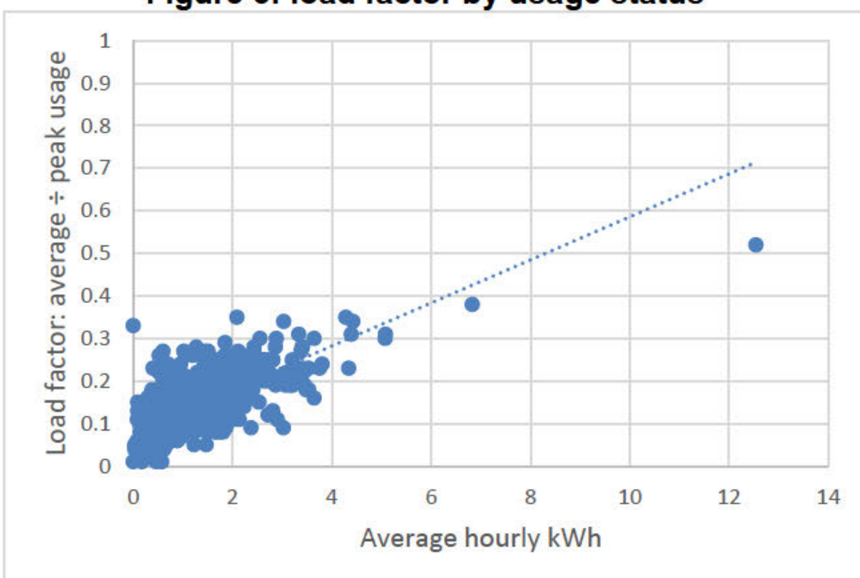
[39] Staff analysis of PGE's response to Staff DR 516, part a.
[40] Ibid.
[41] Staff analysis of PGE's response to Staff DR 516, part b.

count of PGE's load research group is so small. Given the ambiguity of low-income usage patterns in the Pacific Northwest, Staff is willing to support PGE's rate flattening if it has a cost basis because, unlike the EIA data for most other states, there is not clear data that low-income customers would be harmed by the rate flattening. To consider the cost basis, Staff looked at the load factor of customers by average usage:

Figure 3: load factor by usage status[42]



The scatterplot in *Figure 3* above shows that customers with high peak usage also tend to have high average usage. The higher the load factor, the less peaky the customer's usage is and traditionally customers with higher load factors are thought to be less costly to serve. Therefore, PGE's proposal to decrease the price paid by its highest usage customers is not unreasonable to Staff.

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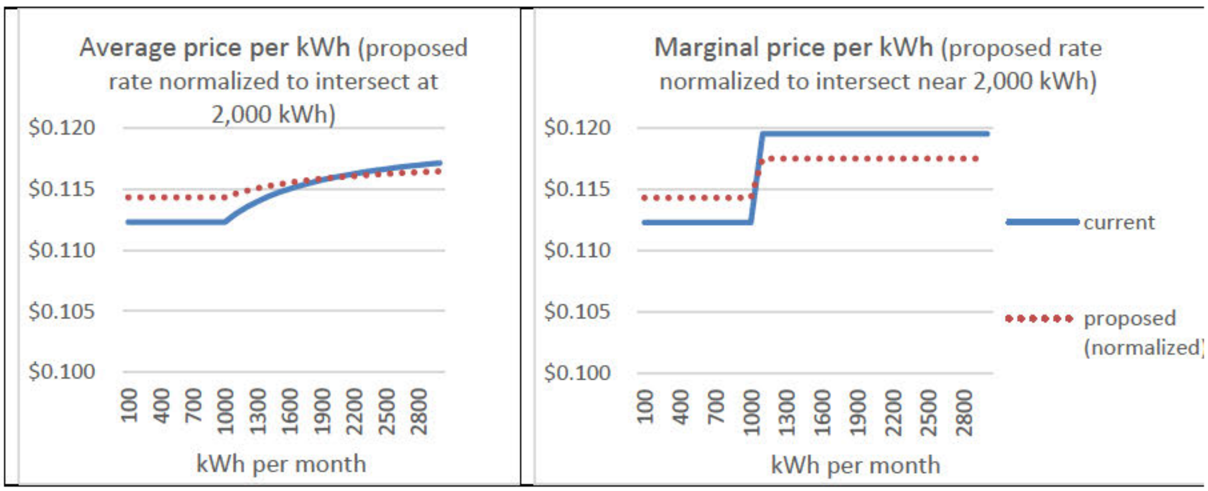
42 Ibid.

Q. How will PGE's rate flattening work?

A. PGE requests an overall rate increase, but when normalized to have similar overall rates as current, the two graphs in *Figure 4* show flattened rates versus current rates:[43]

Figure 4: the impact of proposed flattened residential rates



As *Figure 4* shows, PGE's proposal lowers (flattens) the marginal price for usage above 1,000 kWh per month relative to usage below 1,000 kWh. Customers with very high usage (in this example normalized to customers with usage above 2,000 kWh per month) are better off under PGE's proposal to flatten the residential rate blocking versus under current rates.

Recall from Table 4 above customers using more than 2,000 kWh per month are more likely to be non-low-income, however. Given this fact, Staff doesn't view PGE's rate flattening proposal as a home run, but rather concludes it is not unreasonable assuming the current rate design of the

[43] For simplicity, the monthly fixed per customer charge of about $10 per month is ignored in the graphs.

Schedule 102 Regional Power Act BPA Exchange Credit stays intact to only apply to the first 1,000 kWh per month per customer.[44]

Q. What is Staff's recommendation for separate per customer charges for multifamily residential?

A. Staff supported separate pricing for multifamily residential in PAC's most recent general rate case UE 374. To offset the harmful effects on low-usage customers of higher first block energy charges, Staff recommends rejecting PGE's proposal to increase the single family per customer charge from $11.00 to $12.50. Staff supports PGE's proposal to lower the multifamily per customer charge from $11.00 to $8.00.

Q. What is Staff's recommendation for demand charges for commercial?

A. Staff continues to recommend introduction of a demand charge because large non-residential customers should pay based on cost of service. The current on-peak and off-peak charge is not specific enough. Without a demand charge, PGE's customers have a reduced incentive to minimize costly peaky usage patterns. Staff opposes PGE's proposal to wait until this can be addressed in the resource adequacy docket UM 2143, since appropriate incentives for Schedules 83 and 85 is a separate issue from PGE's perception that direct access customers also do not face appropriate incentives. Further, Schedule 85 customers are relatively large so waiting to set appropriate

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[44] In 2018, PGE proposed "a two-year transition to value all kWh at the same price." (Advice No. 18-21, Initial filing, page 1, available at: https://edocs.puc.state.or.us/efdocs/UAA/uaa155517.pdf).

incentives might have major impacts on PGE's system load. Finally, PAC has demand charges for its large customers.

Q. What is Staff's recommendation about lowering the size cap for customers to join Schedule 90?

A. Because this schedule is so specific (currently a single customer), Staff would like to hear from affected stakeholders. Staff anticipates taking a position after reading other parties Opening Testimony.

Q. Did Staff make any other rate design recommendations in past general rate cases?

A. Yes, in UE 319, Staff suggested PGE to consider replacing its residential fixed charges with minimum bills. Staff repeats this recommendation.

Q. Please describe PGE's requested other rate schedule changes.

A. PGE proposes to expand Schedule 137 (Customer-Owned Solar Payment Option Cost Recovery Mechanism) to long-term and new load direct access customers, increase most line extension allowances, and increase the price of temporary service. PGE also proposes to modify Schedule 146 (Colstrip Power Plant Operating Life Adjustment).[45] Additionally, PGE introduces Schedule 138 (Energy Storage Cost Recovery Mechanism) and Schedule 150 (Transportation Electrification Cost Recovery Mechanism).[46,47]

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45 Staff witness Rose Anderson discusses Schedule 146 in her Exhibit 1900 testimony.

46 Order No. 20-279, page 8 describes that parties agreed not to oppose an AAC for recovery of storage costs for HB 2193.

47 Staff witness Eric Shierman discusses Schedule 150 in his Exhibit 1700 testimony.

Q. Does Staff support PGE's request to expand Schedule 137 to long-term and new load direct access customers?

A. Yes. PGE states that "as the program is legislatively mandated for the broader public good, all customers should support it."[48] Staff concurs that legislation aimed to lower statewide carbon emissions should benefit everyone in the state. This aligns incentives in that direct access customers will better be able to support decarbonization proposals when they are also financial impacted by them.

Q. Does Staff support PGE's request to increase residential line extension allowances?

A. No. PGE's residential line extension allowance was partially approved less than a year ago in Order No. 20-483. Staff does not support increasing the amounts by 18 percent given the recent revision to line extension allowances.[49] Furthermore, PGE is to "provide a review of the line extension allowance using updated data by June 30, 2024." Staff believes that date would be a better time to propose significant changes to the residential line extension amount and that the current line extension amount should not be revised at this time.[50] Finally, PGE's higher residential line extension amounts are computed using PGE's proposed increase in the monthly basic charge, and Staff does not recommend increasing the monthly basic charge.

---

48 PGE/1200, Macfarlane-Tang/44, lines 5-7.
49 An 18 percent increase is $2,660 versus $2,260.
50 Order No. 20-483, UE 385, page 1.

Q. Does Staff support PGE's request to increase the price of temporary service?

A. No. Versus 2018 prices, PGE requests to more than double the price of some temporary services. In UE 319, Staff raised a concern that the PUC's Consumer Services Section receives complaints about the length of time PGE takes to energize the temporary service after the customer has requested the service.[51] PGE responded that hiring new employees will help speed this process up.[52] In response to Staff DR 183, PGE provided the average number of days between a customer request for temporary service and when the temporary service is energized. For the majority of requests, PGE provides the service in less than 15 days; however, there are still many instances where connection takes longer. Staff recommends that the Company's request to increase the Schedule 300 prices not be approved without first hearing from the Company about a service guarantee, such as proposed by Staff in UE 319.[53]

Q. Does this conclude your testimony?

A. Yes.

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51 UE 319/Staff/1300, St. Brown/37, lines 12-15
52 UE 319/PGE/2000, Nicholson-Bekkedahl/4-5.
53 "Staff would like to see customers get temporary service in less than 15 working days whenever extensive construction of utility infrastructure is not required … Staff recommends that in its Reply Testimony, PGE … Describe how PGE envisions compensating customers if it cannot meet its service quality goals." (UE 319/Staff/1300, St. Brown/38-39).

CASE: UE 394
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1401

Witness Qualifications Statements

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	Max St. Brown
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Utility Strategy & Integration Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Ph.D., Economics (2013) Washington State University B.S., Economics (2009) Central Washington University
EXPERIENCE:	I have been employed by the Public Utility Commission from July 2015 to December 2018 and since April 2020, with my current position being a Senior Utility Analyst, in the Utility Program's Strategy & Integration Division. Prior to rejoining the OPUC, I worked as a Senior Economist in the Research Section at the Oregon Department of Revenue. From 2013 to 2015 I served as an Assistant Professor of Economics at Eckerd College, teaching courses including: Econometrics, Labor Economics, and Intermediate Microeconomics. My published research in peer-reviewed academic journals includes a study of the U.S. renewable energy industry and includes international economic impact studies. I have been a witness in Oregon PUC general rate cases: UE 319, UE 374, UG 287, UG 288, UG 305, UG 325, UG 389.

CASE: UE 394
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1402

Exhibits in Support
Of Opening Testimony

October 25, 2021

Exhibit 1402

Staff adjustments to:
UE 394/PGE/816
Bekkedahl - Jenkins/1

Year				Amount	Amount-without-ice-storm
2012	0			0	0
2013	0			0	0
2014	6,394,048			6,394,048	6,394,048
2015	5,862,253			5,862,253	5,862,253
2016	5,001,065			5,001,065	5,001,065
2017	12,463,363			12,463,363	12,463,363
2018	0			0	0
2019	1,865,654			1,865,654	1,865,654
2020	0			0	0
2021	71,500,165	3,600,165	0.0191	72,865,818	3,668,928
				$10,445,220	$3,525,531

CASE: UE 394
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1403

Exhibits in Support
Of Opening Testimony

October 25, 2021

Exhibit 1403, page 1

Staff adjustments to:
UE 394 / PGE / 1202
Macfarlane - Tang / 1

TABLE 4
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS
2022

		Forecast SSEP18E19		TOTAL ELECTRIC BILLS					
				CURRENT	PROPOSED				
	RATE		MWH	with all supplementals except LIA & PPC	with all supplementals except LIA & PPC	Change			
CATEGORY	SCHEDULE	CUSTOMERS	SALES			AMOUNT	PCT.		
Residential	7	809,036	7,555,010	$1,017,035,870	$1,076,326,086	$59,290,216	5.8%	142.47	$134.62
Employee Discount				($1,110,239)	($1,156,809)	($46,570)			
Subtotal				$1,015,925,631	$1,075,169,277	$59,243,646	5.8%	142.31	
Outdoor Area Lighting	15	0	14,480	$3,338,214	$3,602,080	$263,866	7.9%	248.76	
General Service <30 kW	32	94,649	1,576,157	$202,510,144	$218,284,187	$15,774,044	7.8%	138.49	$128.48
Opt. Time-of-Day G.S. >30 kW	38	377	31,528	$4,511,855	$4,521,671	$9,817	0.2%	143.42	
Irrig. & Drain. Pump. < 30 kW	47	2,775	20,075	$4,207,083	$4,412,186	$205,103	4.9%	219.78	
Irrig. & Drain. Pump. > 30 kW	49	1,405	61,430	$9,314,705	$10,040,928	$726,223	7.8%	163.45	
General Service 31-200 kW	83	11,844	2,800,127	$286,246,767	$300,283,967	$14,037,200	4.9%	107.24	
General Service 201-4,000 kW									
Secondary	85-S	1,304	2,134,357	$188,800,488	$188,925,638	$125,150	0.1%	88.52	
Primary	85-P	177	612,588	$50,821,399	$50,947,389	$125,991	0.2%	83.17	0.1%
Schedule 89 > 4 MW									
Primary	89-P	12	562,911	$38,860,057	$39,013,074	$153,018	0.4%	69.31	
Subtransmission	89-T/75-T	5	53,697	$4,426,999	$4,547,159	$120,160	2.7%	84.68	0.6%
Schedule 90	90-P	6	2,824,250	$179,775,368	$179,771,337	($4,031)	0.0%	63.65	$63.65
Street & Highway Lighting	91/95	184	41,836	$9,743,529	$11,192,868	$1,449,339	14.9%	267.54	
Traffic Signals	92	16	2,576	$236,573	$209,355	($27,218)	-11.5%	81.27	
COS TOTALS		921,790	18,291,022	$1,998,718,812	$2,090,921,118	$92,202,307	4.6%	114.31	
Direct Access Service 201-4,000 kW									
Secondary	485-S	230	518,480	$13,982,262	$11,802,612	($2,179,649)			
Primary	485-P	57	373,475	$8,546,222	$6,539,038	($2,007,184)			
Direct Access Service > 4 MW									
Secondary	489-S	1	13,878	$279,362	$257,710	($21,652)			
Primary	489-P	14	1,007,674	$18,538,483	$11,115,091	($7,423,392)			
Subtransmission	489-T	3	243,839	$1,428,178	$1,353,466	($74,711)			
New Load Direct Access Service > 10MW									
Primary	689-P	1	48,674	$640,811	$560,818	($79,993)			
DIRECT ACCESS TOTALS		306	2,206,020	43,415,318	31,628,736	($11,786,582)	-27.1%		
COS AND DA CYCLE TOTALS		922,096	20,497,042	$2,042,134,129	$2,122,549,854	$80,415,725	3.9%	$103.55	

Exhibit 1403, page 2

Staff adjustments to:
UE 394 / PGE / 1204
Macfarlane - Tang / 3

PORTLAND GENERAL ELECTRIC
ALLOCATION OF GENERATION REVENUE REQUIREMENT TO COS CUSTOMERS
2022

Schedules	COS Calendar Energy	Marginal Energy Costs ($000)	Generation Capacity Allocation	Marginal Capacity Costs ($000)	Marginal Capacity & Energy Costs ($000)	Capacity & Energy Allocation Percent	Allocation of Load Following ($000)	Allocated Capacity & Energy Costs ($000)	Cycle Basis Costs ($000)
Schedule 7	7,560,991	$303,988	52.55%	$150,024	$454,012	44.94%	$1,547	$483,980	$483,597
Schedule 15	14,480	$511	0.05%	$148	$659	0.07%	$2	$703	$703
Schedule 32	1,576,916	$62,843	8.03%	$22,916	$85,759	8.49%	$292	$91,420	$91,376
Schedule 38	31,529	$1,261	0.12%	$337	$1,597	0.16%	$5	$1,703	$1,703
Schedule 47	20,699	$877	0.13%	$371	$1,249	0.12%	$4	$1,331	$1,291
Schedule 49	61,728	$2,624	0.42%	$1,197	$3,822	0.38%	$13	$4,074	$4,054
Schedule 83	2,801,114	$112,335	13.68%	$39,052	$151,387	14.99%	$516	$161,380	$161,323
Schedule 85	2,730,198	$106,176	12.20%	$34,821	$140,996	13.96%	$1,375	$151,198	$152,125
Schedule 89/75	615,214	$23,487	2.26%	$6,465	$29,952	2.96%	$1,064	$32,891	$32,966
Schedule 90	2,853,201	$109,048	10.40%	$29,692	$138,740	13.73%	($4,827)	$142,599	$141,152
Schedule 91/95	41,836	$1,478	0.16%	$452	$1,929	0.19%	$7	$2,057	$2,057
Schedule 92	2,576	$99	0.01%	$26	$126	0.01%	$0	$134	$134
TOTAL	18,310,482	$724,727	100.0%	$285,501	$1,010,229	100.00%	($0)	$1,073,469	$1,072,481
Staff Simple Cycle Proxy Plant $/kW				$80.60		**TARGET**		**$1,073,469**	
PGE simple cycle proxy plant $/kW				$87.50					
Projected Peak Load				3,542					
Marginal Capacity Costs ($000)				$285,501					

Exhibit 1403, page 3

Staff adjustments to:
PGE work paper: *2022 Unbundled ROO Initial_Separate Colstrip.xlsx*,
tab: "Unbundled Summary"

PGE
UE 394

Unbundled Summary
Scaled (Thousands)

Line No.	Function	Proposed	UE 335 Customer Touchpoints project ratio	Staff Adjustment	Staff
1	Production Energy - Net	673,547			
2	Production Reliability - Net	389,923			
3	Production Energy - Colstrip	28,140			
4	Production Reliability - Colstrip	27,780			
	production Net	1,063,469		10,000	1,073,469
5	Production Total	1,119,389			
6					
7	Transmission	87,205			
8	Distribution	721,855	9.28%	(928)	720,927
9	Ancillary	5,119			
10	Billing	37,795	38.36%	(3,836)	33,959
11	Metering	6,216	15.64%	(1,564)	4,653
12	Consumer	127,424	36.72%	(3,672)	123,752
13	Total Regulated	2,105,003		$ -	2,105,003
14	total Net	2,049,083			2,049,083
15	Retail / Non-Utility	241			

Exhibit 1403, page 4

Staff adjustments to:
PGE work paper: *Ratespread_ 2022 GRC.xlsx*, tab: "MCenergy"

PORTLAND GENERAL ELECTRIC			
Marginal Energy Costs: 2022 Test Period			
	Staff Marginal Energy Cost	**Energy Percent**	PGE Marginal Energy Cost
Schedules			
Schedule 7	$303,987,982	41.95%	289,178,499
Schedule 15	$511,480	0.07%	486,562
Schedule 32	$62,842,994	8.67%	59,781,451
Schedule 38	$1,260,585	0.17%	1,199,172
Schedule 47	$877,235	0.12%	834,498
Schedule 49	$2,624,488	0.36%	2,496,630
Schedule 83	$112,334,883	15.50%	106,862,228
Schedule 85	$106,175,616	14.65%	101,003,024
Schedule 89/75	$23,486,878	3.24%	22,342,660
Schedule 90	$109,048,188	15.05%	103,735,651
Schedule 91/95	$1,477,781	0.20%	1,405,788
Schedule 92	$99,349	0.01%	94,509
TOTAL	$724,727,459	100.00%	

Exhibit 1403, page 5

Staff adjustments to:
PGE work paper: *Ratespread_ 2022 GRC.xlsx*, tab: "CIO"

PORTLAND GENERAL ELECTRIC CONSUMER IMPACT OFFSET									
Grouping	**Cycle MWH**	**Revenues at Current Prices ($000)**	**2022 Allocated Costs ($000)**	**Percent Change**	**Impact Offset Amount**	**Impact Offset MWH**	**CIO mills/kWh**	**CIO Revenues**
Schedule 7	7,555,010	$1,018,312	$1,108,045	8.8%		7,555,010	(0.65)	($4,907)
Schedule 15	14,480	$3,231	$3,775	16.8%			(20.53)	($297)
Schedule 32	1,576,157	$194,110	$210,368	8.4%		1,576,157	(2.35)	($3,704)
Schedule 38	31,528	$4,332	$4,319	-0.3%			0.00	$0
Schedule 47	20,075	$4,170	$4,354	4.4%			0.00	$0
Schedule 49	61,430	$9,326	$9,999	7.2%			0.00	$0
Schedule 83	2,800,127	$272,881	$282,832	3.6%			0.00	$0
Schedule 85	2,746,945	$248,856.69	$240,647.92	-3.3%		2,746,945	1.05	$2,884
Schedule 89/75	616,608	$62,790.58	$53,622	-14.6%		616,608	0.88	$543
Schedule 90	2,824,250	$176,594	$172,731	-2.2%		2,824,250	1.10	$3,107
Schedules 91 & 95	41,836	$9,398	$10,493	11.6%			7.11	$297
Schedule 92	2,576	$226	$197	-12.6%			0.00	$0
COS TOTALS	18,291,022							
Sch 485 Energy	891,955						1.05	$937
Sch 489 Energy	1,265,391					1,265,391	0.88	$1,114
Sch 689 Energy	48,674						0.88	$43
Totals	20,497,042	$2,004,227	$2,101,384	4.8%	$0	16,584,361		$15
Note: does not include Sch 76R		$0	$0					
Note: does not include employee discount		($1,134)	($1,228)					
Reconcile CIO worksheet to revenues		$2,003,093	$2,100,155					
		$2,006,036	$2,101,640					
		(2,943)	(1,485)					
Schedules	CIO Allocation	MWh	CIO (mills/kWh)					
85/485/585	$3,808,000	3,638,900	1.05					
89/489/589/689	$1,696,000	1,930,673	0.88					
90/490/590	$3,096,000	2,824,250	1.1					
Totals	$8,600,000	8,393,823						
Staff adjustment from 85 and 89 to 90	64%							

CASE: UE 394
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1404

Exhibits in Support
Of Opening Testimony

October 25, 2021

Staff Exhibit 1404 is a Microsoft Excel file
and is being provided digitally.

CASE: UE 394
WITNESS: MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1405

Exhibits in Support
Of Opening Testimony

October 25, 2021

Exhibit 1405, page 1

PGE response to Staff DR 400

August 23, 2021

To: Max St. Brown
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 400
Dated August 9, 2021

Request:

See PGE/800, Bekkedahl-Jenkins/66, line 1:

a. Please specify the percentage increase in the frequency of winter storms; and
b. Please provide all data relied upon in Microsoft Excel format.

Response:

PGE cannot quantify a percentage increase in winter storms since they vary in duration and intensity. However, we do note the following for comparison:

1. From 2014 through 2021 (eight years), PGE has had seven Level III winter storm events and a total of 14 Level III events including the 2020 Labor Day wildfire emergency (see PGE's response to OPUC Data Request No. 401 Attachment 401-A).
2. From 1979 through 2008 (29 years), PGE had 13 winter storm restoration events and a total of 14 storm restoration events, not all of which were Level III events (see PGE's response to OPUC Data Request No. 402, Attachment 402-A).

See also PGE's response to OPUC Data Request No. 406, Attachment 406-A for additional detail.

Exhibit 1405, page 2
PGE response to Staff DR 401

August 23, 2021

To: Max St. Brown
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 401
Dated August 9, 2021

Request:

See PGE/800, Bekkedahl-Jenkins/66, lines 4-5 describing "a greater variety of events and events with greater intensity than were contemplated in Docket UE 215." See also PGE/800, Bekkedahl-Jenkins/71, lines 12-17 describing the type of risk of outage events. In Microsoft Excel format please provide all Level III events by date including:

a. The outage lengths;
b. The costs of each event; and
c. The type of risk [asset risk (electrical infrastructure) versus non-asset risk (weather, vegetation, etc.)].

Response:

Attachment 401-A provides the requested information.

Exhibit 1405, page 3

PGE response to Staff DR 646

September 23, 2021

To: Max St. Brown
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 646
Dated September 9, 2021

Request:

See PGE's confidential response to Staff DR 223. Please provide a revised marginal cost of capacity estimate based on netting out the cost of non-peak cost benefits made available by the presence of a SCCT plant. (See pages 7 and 8 of the Joint Utility Comments submitted in August 2021 in Docket UM 2011).

Response:

PGE estimates non-capacity related energy benefits of $5.43/kW-year in 2022 dollars. Including these benefits would reduce the capacity cost from $87.50 to $82.07/kW-year. The benefit consists of net energy value of $0.41/kW-year (revenues minus variable costs) and flexibility value of $5.02/kW-year. See Attachment 646-A for calculations.

Exhibit 1405, page 4

PGE response to Staff DR 844

September 30, 2021

To: Max St. Brown
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 844
Dated September 17, 2021

Request:

Please describe how investments that span multiple cost categories, such as the Integrated Operating Center (IOC) for transmission and distribution, are allocated between cost categories.

Response:

As discussed in PGE Exhibit 200, Section VII, PGE unbundles its test year costs in accordance with OAR 860-038-0200. Assets that clearly relate to specific functional areas (e.g., thermal and hydro generating plants; transmission towers and conductor; distribution poles, conductor, substations, and transformers) are directly assigned to the applicable functional area. Some general and intangible (G&I) plant is directly assigned, such as general plant at a distribution substation or a generating facility. The majority of G&I plant, however, consists of many smaller assets less clearly attributable to a specific functional area. For these assets, we allocated them to all functional areas based on the O&M labor allocator as specified by OAR 860-038-0200(9)(a)(A) and (E). If the G&I plant is large and separately identifiable but not directly assigned (e.g., the IOC), PGE will establish a basis for allocation. For the IOC, PGE allocated its cost based on the 2022 labor forecasted to occupy it – see unbundling work papers to PGE Exhibit 200, file: "IOC Allocation".

Exhibit 1405, page 5

PGE response to Staff DR 845

October 1, 2021

To: Max St. Brown
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 845
Dated September 17, 2021

Request:

See CUB's UE 335 Opening Testimony (UE 335/CUB/200, Gehrke-Jenks/9-11) which states

> "Nationally, there is an awareness of utilities investing in smart grid applications and distributed energy resources, warranting a need to reconsider how the costs associated with these activities are allocated… For future rate cases, there is a need for better information to guide the allocation of these investments and other smart grid investments utilities will continue to make."

Please describe whether PGE now in UE 394 has better information to guide how smart grid investments are allocated – i.e. per customer versus based on functionality.

Response:

Much of smart grid investment is recorded to Distribution assets as defined by the FERC Uniform System of Accounts. Consequently, PGE assigns these assets to the Distribution function. If the smart grid investment represents general and intangible plant, then PGE will functionalize it as described in PGE's response to OPUC Data Request No. 844. PGE does not otherwise maintain a category of assets identified as Smart Grid for separate functionalization.

Exhibit 1405, page 6

PGE response to Staff DR 183

PGE’s response to Staff DR 183 is a Microsoft Excel file and is being provided digitally.

Exhibit 1405, page 7

PGE response to Staff DR 516

PGE's responses to Staff DR 516, parts a and b are Microsoft Excel files and are being provided digitally.

CASE: UE 394
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Ming Peng. I am a Senior Econometrician employed in the Rates, Finance and Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. I discuss my analysis of the depreciation expense and accumulated depreciation, or depreciation reserve, and portions of Portland General Electric's (PGE or Company) revenue requirement for this rate case as documented by the Company witnesses in PGE/200, Tooman – Batzler. I also discuss my review of the Allowance for Funds Used During Construction (AFUDC) portion of revenue requirement for this rate case.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. DEPRECIATION EXPENSE

Q. What is depreciation?

A. "Depreciation" is defined by the National Association of Regulatory Utility Commissioners (NARUC) in relevant part as follows:

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.[1]

The statement above defines "depreciation" from a valuation perspective. From an accounting perspective, "depreciation" is the allocation of the cost of fixed assets less net salvage to accounting periods, which is a capital recovery concept. From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. Do Oregon statutes address utility depreciation rates?

A. Yes. ORS 757.140(1) states:

> Every public utility shall carry a proper and adequate depreciation account. The Public Utility Commission shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. The rates shall be such as will provide the amounts required over and above the expenses of

[1] NARUC, Public Utility Depreciation Practices, p.318 (1996).

> maintenance, to keep such property in a state of efficiency corresponding to the progress of the industry. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary.

Q. How are depreciation rates determined?

A. Depreciation rates are typically determined separately from general rate cases in dockets specifically opened for the purpose of establishing updated depreciation rates. The dockets are usually initiated by the utility's filing of proposed depreciation rates typically supported by a depreciation study.

To develop depreciation rates, it is necessary to estimate: (1) the combination of survivor curve-service life (Curve-Life) of utility property; and (2) the net salvage (Gross Salvage – Cost of Removal) ratio. Depreciation rates are derived from these two fundamental depreciation parameters, and also include other required elements such as asset value, asset remaining life, and depreciation method.

Q. How are depreciation rates used to determine what to include for depreciation in revenue requirement?

A. To compute the revenue requirement (RR) (RR is measured by cost-of-service), a basic formula is followed:

RR = O&M Expense + "Depreciation" + Taxes + Rate of Return x Rate Base

Depreciation expense & reserve in GRC is derived by (depreciation rate) x (plant in service) x (state allocation factor, if any). Depreciation expense represents a large percentage of total operating expenses. The deferred income taxes, rate base, and cost of capital are all affected by the depreciation.

Q. How is depreciation expense recovered from customers?

A. Depreciation does not have a mechanism to recover itself. Instead, depreciation expense is recovered through a utility's revenue requirement.

A revenue requirement is measured by cost of service, and the depreciation expense is a fixed cost of service, which is calculated by multiplying the depreciation rate by the plant–in–service in a rate base. Therefore, we must have an authorized depreciation rate before we can measure the cost of service and know how much revenue is needed in the rate case. As NARUC states, "[d]epreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses."[2]

Q. Has PGE filed a depreciation study for the purpose of determining the depreciation rates to use in UE 394?

A. Yes. In January 2021, PGE filed a depreciation study (the 2019 Depreciation Study) and proposed depreciation rates. The filing was

2 NARUC, Public Utility Depreciation Practices, p. 195.

docketed as Docket No. UM 2152. Staff, PGE, and the Oregon Citizens' Utility Board (CUB) have entered into a stipulation in UM 2152 agreeing to adjustments to some of depreciation rates included in PGE's initial filing and accepting others as filed. The Association of Western Energy Consumers (AWEC) opposes the UM 2152 Stipulation. Proceedings to resolve the contested matters in UM 2152 are ongoing.

Q. What depreciation rates did PGE use in its Test Year revenue requirement?

A. PGE used the depreciation rates that it included in its initial filing in Docket UM 2152. As of October 18, 2021, PGE has not yet made a supplemental filing in this docket to modify its proposed revenue requirement to be consistent with the depreciation rates that PGE agreed to in the UM 2152 Stipulation. PGE explains that it will wait until the Commission has issued its order determining the depreciation rates in that docket to update its proposed revenue requirement to reflect the adjusted depreciation rates.

Q. What is the difference between the previously approved depreciation rates (UM 1809, Order No. 17-365) and the rates PGE initially proposed in this case for depreciation expense?

A. PGE testifies that the rates resulting from the UM 2152 PGE-filed depreciation study led to a $4.5 million decrease in depreciation expense for the plant in service included in our Test Year rate base.[3]

[3] PGE/200, Tooman-Batzler/13, lines 5-8.

Q. How does PGE's 2022 depreciation expense forecast compare to 2020 actuals?

A. The total forecasted depreciation for 2022 reflects a $14.1 million increase over 2020 actuals.

Q. What are the primary drivers for the increase?

A. PGE explains that the primary drivers of the increase in depreciation expense in its initial filing are:[4]

- $15.0 million for transmission and distribution facilities;
- $11.3 million for the Colstrip generation plant to reflect the change of depreciable life from the year 2030 to 2027 as specified in PGE's depreciation study filed in Docket UM 2152;
- $8.1 million for general plant including the addition of the new Integrated Operations Center (IOC);
- $6.2 million for hydro generation resources, thermal plants, and solar; and
- $5.3 million for the Wheatridge wind generation plant, which was placed in service in December 2020. Customer prices, however, already reflect the full year of the Wheatridge revenue requirement, including depreciation expense, in accordance with Commission Order No. 20-279.

These increases are partially offset by:

[4] UE 394 / PGE / 200, Tooman – Batzler / 13.

- $28.9 million reduction for the retirement of the Boardman generating plant in Q4 2020; and
- $6.6 million reduction in Biglow and Tucannon wind generation resources.

Q. Do you propose an adjustment to depreciation expense in UE 394?

A. Not at this time. Staff and PGE agree that because the Commission is still considering the Joint Settlement in UM 2152, it does not make sense to adjust or make corrections to depreciation expense.

ISSUE 2. DEPRECIATION RESERVE

Q. Describe the Depreciation & Amortization Reserve.

A. Depreciation reserve is determined by looking at the accumulated depreciation at a point in time, the total amount of recorded depreciation, retirements, gross salvage, cost of removal, transfer asset, and other adjustments.

Amortization, like depreciation, relates to intangible assets, such as computer software and regulatory assets. Reserves are affected by depreciation expenses, amortization expenses, retirements, gross salvage, cost of removal, and other adjustments. If depreciation expense was changed, the accumulated depreciation and amortization should be changed accordingly. PGE's proposed rate base balance in its filing is a forecast of its rate base balances as of April 30, 2022, in which the accumulated reserve is $5.3 billion.

4/30/2022 Rate Base in Filing	
$ 11,630,139,539	Gross Plant
$ (5,284,043,933)	Accumulated Reserve
$ 6,346,095,606	Net Plant

Q. Have you proposed any adjustments on PGE's depreciation reserve in the UE 394 rate case filing?

A. No. As explained above, Staff and PGE agree that any adjustments are premature while the UM 2152 settlement is under consideration by the Commission.

ISSUE 3. AFUDC

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to discuss my analysis of whether the Company complied with guidance[5] related to AFUDC and the capitalization of assets based on the regulations of the Federal Energy Regulatory Commission (FERC) and the OPUC in this filing.

Q. What is AFUDC?

A. AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized during construction as part of the cost of utility plant. Electric (Gas) Plant Instruction no. 3(17) provides a formula for computing rates used to capitalize AFUDC.[6] The formula includes a component for the weighted average cost of long-term debt. The entire issue of the use-restricted long-term debt should be included with other long-term debt used in calculating AFUDC rates. Average balances of the trust or other special funds should be included in the computation of the average balance of construction work in progress (CWIP) used in the formula.

AFUDC assigned to the project should be determined by applying AFUDC rates to the eligible project expenditures and to balances in the

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5 FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101

6 https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters/allowance-funds-used-during-construction

trust or special funds. Fund earnings during construction should be credited to the cost of construction of the project facilities.

Q. Please provide more details regarding AFUDC.

A. AFUDC is a non-cash item that is included in the cost of Utility Group utility plant and represents the cost of borrowed and equity funds used to finance construction. AFUDC is the cost of both the debt and equity funds used to finance utility plant additions during the construction period for such additions, determined in accordance with Generally Accepted Accounting Principles (GAAP).

FERC has prescribed two formulas for calculating maximum allowable AFUDC rates:[7]

1) DEBT: This formula determines the maximum rate that can be used to capitalize an allowance for borrowed funds (i.e., debt) used for construction purposes.

2) COMMON EQUITY: This formula determines the maximum rate that can be used to capitalize an allowance for other funds (e.g., common equity) used for construction purposes.

FERC has indicated that if the FERC AFUDC rate is different than the state approved rate, the AFUDC capitalized should be split between utility plant and a regulatory asset. The amount capitalized in utility plant would be based on the FERC AFUDC rate. The amount included in the

[7] FERC 18 C.F.R. Part 101 (17). https://www.law.cornell.edu/cfr/text/18/part-101

regulatory asset would be the difference between the State AFUDC rate (7.30 percent) and the FERC AFUDC rate (6.68 percent for 2021).

The FERC formula elements for the computation of the allowance for funds used during construction are:[8]

Ai=s*(S/W)+d*(D/D+P+C)*(1-S/W) = Gross allowance for borrowed funds used during construction rate

Ae=[1-S/W]*[p*(P/D+P+C)+c*(C/D+P+C)] = Allowance for <u>other</u> funds used during construction rate

S=Average short-term debt
s=Short-term debt interest rate
D=Long-term debt
d=Long-term debt interest rate
P=Preferred stock
p=Preferred stock cost rate
C=Common equity
c=Common equity cost rate
W= Average balance in construction work in progress, less asset retirement costs related to plant under construction

I verified that PGE's capital structure (Debts-bond/Equity-stocks ratios) used for AFUDC is the same as stipulated to in PGE's UE 394 case. PGE complied with the authorized capital structure of 50 percent debt (Bonds: borrow money from bank and pay interest; is tax deductible) and 50 percent equity.

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8 FERC 18 C.F.R. Part 101 (17) Allowance for funds used during construction (a), (b). https://www.law.cornell.edu/cfr/text/18/part-101

I confirmed that PGE did not include CWIP in the rate base, because the Commission does not allow a utility to put a plant not yet placed in service into a rate-base.

A. CALCULATED AFUDC RATE:

	AFUDC	AFUDC	AFUDC	Authorized	Authorized	Authorized		
Year	Debt	Equity	Total AFUDC	LT Debt	Common Equity	WACC	OPUC	OPUC
	Rate	Rate	Rate	Rate	Rate	Rate	Order #	Docket #
2017	2.46%	4.82%	7.28%	5.20%	9.50%	7.35%	17-511	UE 319
2018	2.52%	4.79%	7.30%	5.10%	9.50%	7.30%	18-467	UE 335
2019	2.40%	4.73%	7.13%	5.10%	9.50%	7.30%	18-467	UE 335
2020	2.30%	4.56%	6.86%	5.10%	9.50%	7.30%	18-467	UE 335
2021	2.28%	4.40%	6.68%	5.10%	9.50%	7.30%	18-467	UE 335
2022	2.33%	4.25%	6.58%					UE 394

Q. Did you make any adjustment after the review?

A. No. Staff proposed no adjustment to PGE's original filing for the following reasons:

- <u>The Company's AFUDC Monthly Rates are compliant with FERC requirements</u>: The Company's calculation of its monthly AFUDC Rates complies with the FERC AFUDC rate formulas and accounting requirements. The monthly calculation method has been authorized by FERC. Per FERC Order No. 561, on April 8, 1982, PGE was granted FERC approval to calculate AFUDC rates on a monthly basis utilizing balances and applicable cost levels, as of the end of preceding month, for all components of capital, and utilizing estimates of CWIP balances and short-term debt balances and cost rates in the month that the AFUDC rate is to be used. In general, FERC approval to calculate AFUDC rates is on a semiannual basis.

- The Company satisfied FERC guidelines for its construction investment: Under FERC's AFUDC calculation guide, PGE used both debt funds and equity funds for its construction investment. I found that PGE tried to balance its capital structure and they used the debt fund and equity fund proportionally.
- The Company satisfied OPUC requirements: PGE's AFUDC rates are lower than the authorized rate of return in Oregon (Weighted Average Cost of Capital - WACC). The Company's authorized rate of return is 7.30 percent.
- The Company's facility is excluded from AFUDC: The Company complies with the FERC requirement for a plant not yet in service. In the month it is placed in service, the facility being constructed is excluded from AFUDC base after and thus, AFUDC accrual for the facility ceases.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1501

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME: Ms. Ming Peng

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Econometrician
Energy Rates, Finance, and Audit Division

ADDRESS: 201 High Street SE, Suite 100
Salem, OR 97301

EDUCATION & TRAINING:

M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

CRRA Certified Rate of Return Analyst in 2002
Society of Utility and Regulatory Financial Analysts

Depreciation studies – the Society of
Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

400+ credit hours on 30+ training topics in the public utility industry

EXPERIENCE: 1/11/1999 – Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 22 years. My roles include:

Expert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst:

I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in the public utility industry.

Principal Analyst and Case Manager, Settlement Lead/Negotiator for Depreciation Ratemaking:

I have served as a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) for the past 12 years. In this role, I've had a strong focus on Depreciation Rate Determination (fixed cost allocation, and capital recovery). I was also a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) during this time period.

In this position, I investigated, analyzed, and calculated energy asset retirement cost and impact, as well as power plant decommissioning cost and impact, on customer rates. I reviewed, calculated, and analyzed fixed asset depreciation and proposed depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on Steam/Coal, Hydraulic, Natural Gas, Wind, Solar, and Geothermal.

My analyses of "Power-Plant-Shutdown" activities (accelerated plant retirement, and decommissioning cost recovery) include the following cases:

1. PGE closes Boardman Coal-fired plant (UM 1679 & UE 215).
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246).
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 – Recovery of investment in Klamath River dams in OPUC UE 219.
4. Idaho Power Valmy Coal-fired power plant Shutdown (UE 316).
5. PGE Colstrip Coal-fired power plant Shutdown (UM 1809).

I conduct case investigations and analyses on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG, Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my current position, I was a Lead Analyst and Case Manager for cost of debt capital for nine years. I reviewed market risks, derivatives and hedging, debt issuance, and stock flotation. My analysis directly informed utility and energy policy.

I advised the Commission on over 60 financial dockets. The Commission incorporated all of my recommendations into final orders.

I was certified by the Society of Utility and Regulatory Financial Analysts as a Certified Rate of Return Analyst in 2002.

Public Utility & Policy Analyst:

Rulemaking: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

Energy Utility Merger & Acquisition: I have testified in formal state hearings involving utility mergers & acquisitions. I conducted Acquisition Premiums & Credit Risk Analysis and testified on behalf of the Commission in MidAmerican Energy Company's application to purchase PacifiCorp. I also reviewed Scottish Power's earlier purchase of PacifiCorp, and PGE's emergence from Enron after the Enron bankruptcy.

Integrated Resource Planning (IRP, Least Cost Planning): I provided comments to the Commission for decision making on Boardman to Hemingway (B2H), a 500-kV transmission power line, which included a cost and benefit list, a pros and cons list, alternatives, and the relevant legal risks. I also provided comments on utility's IRPs, such as total cost for power generation, power capacity (MW) replacement cost, avoided cost for free fuel, and emission trading cost.

Clean Energy – Dollar Impact on Customer Rates: I analyzed and calculated the rate impact and comparative advantage of clean energy. I built the portfolio optimization models to analyze the coal-fired generating capacity replacement.

General Rate Cases: I have been a part of *almost every energy rate case* since I joined the Oregon PUC on 1/11/1999. Historically, my review included fuel price forecasting, property sales, load forecasting, weather normalizations, cost of debt, and capital structures. Currently, my reviews are focused on depreciation and reserve, and AFUDC Capitalization Policy.

Survey Sampling Design: Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 1288.

Auditing, Interest Rate, Late Payment: I audited cost of capital and financial components. My survey report and analyses are published annually for Oregon (UM 779).

Survey for Market Competition & Economic Policy: I conducted and wrote the report on Telecommunications, "Market Competition and Economic

Policy Survey Analysis" for House Bill 2577. This report has been published on the OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators:
I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My "Mentoring Topics" focus on Incentive Regulation; Rate and Economic Impacts of "Cost-of-Service" regulation in the U.S. and "Price-Cap Performance Based Regulation" in Europe; Cost of Capital, Energy Demand and Price Forecasting Modeling; Least Cost Planning; Regulatory Policy; and Renewable Energy issues within regulated rate structures.

CASE: UE 394
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1502

Exhibits in Support
Of Opening Testimony

October 25, 2021

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 186
Dated July 29, 2021

Request:

Please insert data links in the Company's Excel work paper provided in this docket that will enable Staff to verify the following:

a. Plant Balance,
b. Depreciation Rates,
c. Depreciation Expense,
d. Depreciation Reserve, and
e. Oregon Allocation Factors, which are all tied to the Revenue Requirement Excel Model.

Response:

a. Attachment 186-A provides plant balance detail supporting amounts included in PGE Exhibit 201.
b. Attachment 186-A provides depreciation rate detail supporting amounts included in PGE Exhibit 201.
c. Attachment 186-A provides depreciation expense detail supporting amounts included in PGE Exhibit 201.
d. Attachment 186-A provides depreciation reserve detail supporting amounts included in PGE Exhibit 201.
e. All amounts are 100% allocated to Oregon.

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 187
Dated July 29, 2021

Request:

In addition, please provide the calculations for, (1) links, (2) formulas, (3) references, (4) term definitions to the following work papers:

a. Revenue Requirements Model;
b. Gross Plant;
c. Depreciation and Amortization Expense link to Depreciation Rates as used in this filing. (The depreciation rate is addressed in the stipulation under the UM 2152.)

Response:

a. The PGE Exhibit 200 non-confidential workpaper, "Exhibit Support 2022," provides PGE's Revenue Requirements Model, with supporting data. Specifically, the tab "Rev Req Base" provides PGE's full revenue requirement (including the costs related to Colstrip) with formulas and links intact supporting PGE Exhibit 201.
b. Attachment 186-A provides the Gross Plant detail supporting amounts included in PGE Exhibit 201.
c. Attachment 186-A provides the requested detail supporting amounts included in PGE Exhibit 201.

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 188
Dated July 29, 2021

Request:

Please provide the Company's forecasted Accumulated (1) Depreciation and (2) Amortization. Please include detailed calculation links for accumulated depreciation/amortization, retirement, amortization, and other elements that will add up to total in the Company's Revenue Requirement Excel model.

Response:

Attachment 186-A provides the requested detail supporting amounts included in PGE's 2022 revenue requirement as presented in PGE Exhibit 201.

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 189
Dated July 27, 2021

Request:

Please provide:

a. The current Oregon authorized Weighted Average Cost of Capital (WACC);
b. The Company's weighted average cost of capital (WACC) data from 2017 through 2022;
c. Current Oregon Authorized Capital structure: Debt/Equity Ratio;
d. The Company's Capital structure: Debt/Equity Ratio from 2017 through 2022; and
e. The current Oregon Authorized Return on Equity

Response:

a. PGE's current authorized Weighted Average Cost of Capital (WACC) is 7.300%, authorized in UE 335, based on a cost of long-term debt of 5.100%, return on equity of 9.50%, and a 50/50 capital structure.
b. PGE's actual WACC from 2017 through 2020 is sourced from its annual Results of Operations Report. PGE's WACC in 2021 and 2022 is based on current forecast estimates. See attachment 189-A.
c. PGE's current authorized capital structure is 50% debt and 50% equity. This was authorized in Order No. 18-464 in Docket No. UE 335
d. PGE's actual capital structure from 2017 through 2020 is sourced from its annual Results of Operations Report. PGE's capital structure in 2021 and 2022 is based on current forecast estimates. See attachment 189-A.
e. PGE's current authorized Return on Equity, ROE, is 9.5%. This was authorized in Order No. 18-464 in Docket No. UE 335.

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 190
Dated July 29, 2021

Request:

Regarding AFUDC Accounting (Allowance for Funds Used During Construction-AFUDC, Construction Work-in-Progress-CWIP), please explain in detail whether the Company's calculation of its AFUDC rates comply with the FERC AFUDC rate formulas and accounting requirements. If not, please explain why.

Response:

PGE's calculation of AFUDC rates complies with the FERC AFUDC rate formulas and accounting requirements. Additionally, on April 8, 1982, PGE was granted FERC approval to calculate AFUDC rates on a monthly basis utilizing balances and applicable cost levels, as of the end of preceding month, for all components of capital, and utilizing estimates of construction work in progress balances and short-term debt balances and cost rates in the month that the AFUDC rate is to be used. Attachment 190-A provides the above referenced approval letter from FERC.

PORTLAND GENERAL ELECTRIC COMPANY
121 S.W. SALMON STREET
PORTLAND, OREGON 97204
(503) 226-8890

CD HOBBS
ICE PRESIDENT
D CONTROLLER

March 22, 1982

Mr. Loren H. Drennan, Jr.
Chief Accountant
Federal Energy Regulatory Commission
825 N. Capitol Street, N.W.
Washington, D.C. 20426

Dear Mr. Drennan:

Re: Order 561 - Determination of Allowance for Funds Used During Construction

Portland General Electric Company ("PGE") currently accounts for Allowance for Funds Used During Construction ("AFDC") using the prescribed Federal Energy Regulatory Commission ("FERC") formula. PGE is not requesting a change from the formula concept of Order No. 561. This letter is written, however, to request FERC approval to compute AFDC on a monthly basis utilizing balances and applicable cost levels, as of the end of the preceding month, for all components of capital, and utilizing estimates of construction work in progress balances and short-term debt balances and cost rates in the month that the AFDC rate is to be used. Also, compounding of previously capitalized AFDC will be done no more frequently than semiannually.

PGE believes this request will permit a more appropriate tracking of changes in the capital components of AFDC. As you are no doubt aware, interest costs have increased significantly, and new types of financing have been utilized subsequent to the issuance of Order No. 561. The current formula does not allow for timely recognition of these changes. As a result, we request that those components of the AFDC formula that are now fixed for stated periods of time be allowed to change when the capital structure and related capital costs change.

Should you have any questions, please direct them to E. Wayne Fordice, Assistant Controller at (503) 226-8571.

Sincerely,

CDHobbs

cc: Ken Harrison

APR 12 1982

CD HOBBS
VICE PRESIDENT
AND CONTROLLER

Fcrc

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON 20426

IN REPLY REFER TO:
OCA

APR 8 1982

CD Hobbs, Vice President
and Controller
Portland General Electric
Company
121 S. W. Salmon Street
Portland, Oregon 97204

Dear Mr. Hobbs:

This is in reply to your letter dated March 22, 1982, in which you requested that Portland General Electric Company be permitted to compute AFUDC on a monthly basis utilizing balance and applicable cost levels, as of the end of the preceding month, for all components of capital and utilizing estimates of construction work in progress balance and short-term debt balances and cost rates in the month that the AFUDC rate is to be used. You indicated that compounding of previously capitalized AFUDC will be done no more frequently than semiannually.

Your request is approved.

Sincerely yours,

L. H. Drennan, Jr.
L. H. Drennan, Jr.
Chief Accountant

APR 12 1982

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 191
Dated July 29, 2021

Request:

AFUDC Accounting (Allowance for Funds Used During Construction-AFUDC, Construction Work-in-Progress-CWIP), please fill out the attached computational table Attachment A with calculation formulas for each year from 2017 through 2022. The tables should identify: A) the sources of funds, B) the amount or balance of such funds, C) the applicable cost rates for such funds, D) Construction Work-in-Progress CWIP, E) the relative weight that should be given to those sources of funds, and F) the derivation of the AFUDC rates.

Response:

Attachment 191-A provides the requested information.

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 192
Dated July 29, 2021

Request:

Under FERC AFUDC Accounting, the formulas assume that short-term debt is the first source of construction funding. If the balance of short-term debt exceeds the average balance of CWIP, the total AFUDC rate is comprised of only an allowance for borrowed funds used during construction equal to the short-term debt rate. Were these the assumptions on which the Company's formulas are based? If not, please explain why.

Response:

PGE's AFUDC rate formulas are based on the assumptions that short-term debt is the first source of construction funding. On June 30, 2020, FERC granted a temporary 12-month waiver of certain provisions of 18 C.F.R pt. 101 to modify the existing AFUDC rate calculation beginning March 2020 and expiring in February 2021 (subsequently extended through September 30, 2021), in response to the COVID-19 pandemic. In this waiver, FERC permits utilities to use a simple average of short-term debt balances for the year ended 2019 in the FERC prescribed AFUDC rate formula. All other components of the rate formula remain unchanged.

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 193
Dated July 29, 2021

Request:

If the average balance of CWIP exceeds the balance of short-term debt, the calculation assumes that the construction funding was not met by short-term debt. Please explain in detail, with a narrative response, how the Company incorporated the different capital sources and cost rates to arrive at the total, debt, and other funds' maximum allowable AFUDC rates?

Response:

PGE calculates AFUDC rates in accordance with FERC guidance in 18 C.F.R. pt. 101 Electric Plant Instruction. When construction funding is not met by short-term debt, PGE calculates maximum allowable AFUDC rates relevant to long-term debt by multiplying total long-term debt cost rate by the ratio of total long-term debt to total capitalization. The maximum allowable AFUDC rates relevant to other funds (common equity & preferred stock) are calculated by multiplying the current authorized return on equity (ROE) by the ratio of total common equity to total capitalization. Lastly, cost rates for debt and equity sources of financing are each multiplied by 1 minus the ratio of weighted average short-term debt to construction work in progress in order to reflect that short-term debt financing is assumed to be the first source of financing in capital construction.

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 194
Dated July 29, 2021

Request:

Has the Company put its CWIP into the rate base for capital recovery?

Response:

No. PGE did not include CWIP within rate base for Docket No. UE 394.

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 195
Dated July 29, 2021

Request:

Please provide the CWIP/AFUDC information. Include:

a. PGE's capitalized AFUDC including the total dollar amount for its projects in Excel worksheets. Include with the response all supporting explanations, notes, and calculations.

b. A list of Projects and Costs excluded from AFUDC Base and a list of Projects and Costs included in AFUDC Base in an Excel spreadsheet.

Response:

Attachment 195-A provides the requested information.

August 12, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 196
Dated July 29, 2021

Request:

Please explain whether the Company complies with FERC's requirement: "AFUDC accruals must cease once the facility being constructed has been tested and is ready for, or placed in, service".

Response:

Yes, the Company complies with the FERC requirement. In the month after it is placed in service, the facility being constructed is excluded from AFUDC base and thus, AFUDC accrual for the facility ceases.

September 3, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 512
Dated August 20, 2021

Request:

What is the AFUDC FERC rate you used? For example, FERC's rate of 6.12% for 2018 is calculated based on guidance in the Uniform System of Accounts under CFR part 101.

Response:

PGE’s Response to OPUC Data Request No. 191, Attachment 191-A provides AFUDC rates from January 2017 to December 2022.

September 3, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 513
Dated August 20, 2021

Request:

How did you follow FERC's guidance on calculating the AFUDC rate? FERC has indicated that if the FERC AFUDC rate is different than the state approved rate, the AFUDC capitalized should be split between utility plant and regulatory asset. The amount capitalized in utility plant would be based on the FERC AFUDC rate. The amount included in the regulatory asset would be the difference between the State AFUDC rate (x.xx%) and the FERC AFUDC rate (x.xx%) for 2017-2022.

a. Please list all AFUDC FERC rates and State rates that are applicable to the rate base additions in UE 394; and
b. If there are multiple rates, please identify the rates and what assets and time periods they were or are applicable.

Response:

PGE follows FERC's guidance to calculate AFUDC rates as described in PGE's Response to OPUC Data Request No. 190. There is no difference between the State AFUDC rate and FERC AFUDC rate.

a. As there is no difference between the AFUDC FERC rates and State rates, PGE's Response to OPUC Data Request No. 191, Attachment 191-A provides the requested information.
b. There are not multiple rates used, and as described in PGE's Response to OPUC Data Request No. 190, PGE calculates AFUDC rates monthly and applies the same rates for all eligible assets.

September 3, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 514
Dated August 20, 2021

Request:

How often does PGE calculate AFUDC per year? FERC AFUDC rate is calculated quarterly. If PGE calculates quarterly AFUDC rates, please list and identify each quarterly rate. If PGE uses different AFUDC for different assets, please identify the assets to which the different rates apply.

Response:

As described in PGE's Response to OPUC Data Request No. 190, PGE calculates AFUDC rates on a monthly basis. PGE's Response to OPUC Data Request No. 190, Attachment 190-A provides the approval from FERC for the monthly AFUDC rate calculation. PGE does not use different AFUDC rates for different assets.

September 3, 2021

To: Ming Peng
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 515
Dated August 20, 2021

Request:

Please identify and describe each exception FERC has authorized for PGE to FERC's standard AFUDC guidelines.

Response:

As described in PGE's Response to OPUC Data Request No. 190, on April 8, 1982, PGE was granted FERC approval to calculate AFUDC rates on a monthly basis utilizing balances and applicable cost levels, as of the end of preceding month, for all components of capital, and utilizing estimates of construction work in progress balances and short-term debt balances and cost rates in the month that the AFUDC rate is to be used. PGE's Response to OPUC Data Request No. 190, Attachment 190-A provides the above referenced approval letter from FERC.

As described in PGE's Response to OPUC Data Request No. 192, on June 30, 2020, FERC granted a temporary 12-month waiver of certain provisions of 18 C.F.R pt. 101 to modify the existing AFUDC rate calculation beginning March 2020 and expiring in February 2021 (subsequently extended through September 30, 2021), in response to the COVID-19 pandemic. In this waiver, FERC permits utilities to use a simple average of short-term debt balances for the year ended 2019 in the FERC prescribed AFUDC rate formula. All other components of the rate formula remain unchanged.

PORTLAND GENERAL ELECTRIC COMPANY
121 S.W. SALMON STREET
PORTLAND, OREGON 97204
(503) 226-8090

CD HOBBS
ICE PRESIDENT
D CONTROLLER

March 22, 1982

Mr. Loren H. Drennan, Jr.
Chief Accountant
Federal Energy Regulatory Commission
825 N. Capitol Street, N.W.
Washington, D.C. 20426

Dear Mr. Drennan:

Re: Order 561 - Determination of Allowance for Funds Used During Construction

Portland General Electric Company ("PGE") currently accounts for Allowance for Funds Used During Construction ("AFDC") using the prescribed Federal Energy Regulatory Commission ("FERC") formula. PGE is not requesting a change from the formula concept of Order No. 561. This letter is written, however, to request FERC approval to compute AFDC on a monthly basis utilizing balances and applicable cost levels, as of the end of the preceding month, for all components of capital, and utilizing estimates of construction work in progress balances and short-term debt balances and cost rates in the month that the AFDC rate is to be used. Also, compounding of previously capitalized AFDC will be done no more frequently than semiannually.

PGE believes this request will permit a more appropriate tracking of changes in the capital components of AFDC. As you are no doubt aware, interest costs have increased significantly, and new types of financing have been utilized subsequent to the issuance of Order No. 561. The current formula does not allow for timely recognition of these changes. As a result, we request that those components of the AFDC formula that are now fixed for stated periods of time be allowed to change when the capital structure and related capital costs change.

Should you have any questions, please direct them to E. Wayne Fordice, Assistant Controller at (503) 226-8571.

Sincerely,

CDHobbs

cc: Ken Harrison

APR 12 1982

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON 20426

CD HOBBS
VICE PRESIDENT
AND CONTROLLER

IN REPLY REFER TO:
OCA

APR 8 1982

CD Hobbs, Vice President
and Controller
Portland General Electric
Company
121 S. W. Salmon Street
Portland, Oregon 97204

Dear Mr. Hobbs:

This is in reply to your letter dated March 22, 1982, in which you requested that Portland General Electric Company be permitted to compute AFUDC on a monthly basis utilizing balance and applicable cost levels, as of the end of the preceding month, for all components of capital and utilizing estimates of construction work in progress balance and short-term debt balances and cost rates in the month that the AFUDC rate is to be used. You indicated that compounding of previously capitalized AFUDC will be done no more frequently than semiannually.

Your request is approved.

Sincerely yours,

L. H. Drennan, Jr.
Chief Accountant

APR 12 1982

CASE: UE 394
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1600

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Anna Kim. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1601.

Q. What is the purpose of your testimony?

A. I present Staff analysis on Research and Development (R&D) funds.

Q. How is your testimony organized?

A. My testimony is organized as follows:

RESEARCH AND DEVELOPMENT

Q. What are R&D expenses?

A. R&D expenses are expenses for research, development, and demonstrations that are related to the utility's current or future business. These expenses include work with technologies that are not yet technically and commercially viable. These activities may be conducted directly by the utility or through a third party.[1]

Q. Please summarize the Company's overall request for R&D expense.

A. The Company is proposing an R&D budget increase from $2.6 million in 2019 to $2.7 million in 2022.[2]

Q. How did the Company calculate the budget for R&D expenses?

A. The Company used the methodology stipulated in UE 335:

> PGE will determine the percentage of fixed Transmission and Distribution ("T&D") and Generation Operations and Maintenance ("O&M") costs (excluding Boardman) in the test year forecast that $2.6 million represents and the Stipulating Parties agree to apply that percentage from this rate case to determine a presumptive reasonableness of R&D costs in PGE's next three rate cases, or 10 years, whichever occurs first.[3]

The Company determined that in UE 335, the stipulated $2.6 million budget represents 0.825 percent of final UE 335 T&D and generation fixed O&M, excluding Boardman. The Company applied this percentage to the 2022

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1 Conservation of Power and Water Resources Rule, 18 C.F.R. § 101.32B (2021).
2 PGE/400, Ajello – Batzler/23.
3 Order No. 19-129, Appendix A, pages 2-3.

forecast and calculated a R&D budget of $2.7 million. The Company proposes using the $2.7 million budget for R&D.[4]

Q. How did Staff review these costs?

A. Staff reviewed the data provided through UE 394 Exhibit 400 and additional DRs. Staff reviewed costs to determine if costs are appropriately categorized for R&D spending. Staff reviewed relevant processes the Company established to manage the R&D budget.

Q. When reviewing these costs, what did Staff find regarding the processes the Company uses to manage R&D investments?

A. Staff found that the Company had established processes to select and monitor R&D projects, and to disseminate findings from their R&D investments internally. The Company has a process with specific criteria to evaluate and prioritize projects.[5] The Company specifically considers whether a project should be undertaken as part of a larger group of funders or separately.[6] Each R&D project requires a final report comparing the outcomes of the research activity to the initial proposal.[7] The Company holds quarterly meetings where the results of R&D research are distributed.[8]

Q. How does the Company determine whether a project should be funded separately or in collaboration with other utilities?

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4 PGE/400, Ajello – Batzler/23.
5 Staff/1602, Kim/1602, PGE Response to Staff DR 607.
6 Staff/1602, Kim/1602, PGE Response to Staff DR 608.
7 Staff/1602, Kim/1602, PGE Response to Staff DR 606.
8 Staff/1602, Kim/1602, PGE Response to Staff DR 605.

A. The Company determines whether a research activity is specific to the circumstances of the utility and its customers or if the research needs are more general. The Company prefers to work with industry groups, national labs, and universities, leveraging funds to gain more insights.[9]

Q. Is Staff proposing adjustments for R&D costs?

A. No. The method to calculate a presumptive reasonable budget amount was set in UE 335 for this rate case, and the amount proposed by the Company appears to be consistent with this presumed reasonable amount.[10] As a result, I propose no adjustments in my testimony.

Q. Does Staff have other recommendations for R&D costs?

A. Yes. Staff recommends that PGE continue to provide annual reports regarding its R&D spending. In UE 294, the Commission adopted a stipulation in which PGE agreed to file R&D spending reports until its next general rate case.[11] PGE provided these spending reports and Staff thinks the reports were very valuable. Staff recommends the Commission renew the requirement for PGE to file an annual report on R&D activities during the previous year.

Q. Why does Staff recommend ongoing reporting?

A. Staff finds that, overall, the Company has effective processes in place to manage and benefit from its R&D investments. However, these investments are also intended to provide benefits to its customers, and the benefits attained

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[9] Staff/1602, Kim/1602, PGE Response to Staff DR 608.
[10] Order No. 19-129, Appendix A, pages 2-3.
[11] Order No. 15-356, App. A, p. 2.

are not readily available to the public. Staff believes establishing ongoing annual reporting will provide this transparency.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1601

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	Anna Kim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Economics Portland State University, Portland, OR Master of Environmental Studies, The Evergreen State College, Olympia, WA Bachelor of Arts, Economics University of California, Berkeley, CA
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) since July 2018 in the Energy Resources and Planning Division. My responsibilities include providing advice on energy efficiency policy, pilot and program evaluation, and oversight of energy efficiency programs run through the Energy Trust of Oregon Prior to working for the Commission, I worked for Seattle City Light as a power resource planner developing integrated resource plans. I also worked for five years as an evaluation consultant which involved evaluating energy efficiency and demand response pilots and programs and market research.

CASE: UE 394
WITNESS: ANNA KIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1602

Exhibits in Support
Of Opening Testimony

October 25, 2021

September 15, 2021

To: Anna Kim
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 605
Dated September 2, 2021

Request:

Please provide a narrative description of the process the Company undertakes to distribute or implement findings from R&D projects? What process does the Company use to distribute information across PGE departments?

Response:

PGE's R&D committee meets quarterly with key organizational leaders to discuss current and future R&D efforts. In these meetings, R&D project leaders present significant projects and how PGE might utilize the findings. It is through the connection of R&D to organizational leadership and department subject matter experts that the results get passed throughout the organization.

September 15, 2021

To: Anna Kim
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 606
Dated September 2, 2021

Request:

Referencing the Company's response to DR 389, please provide a narrative description of the process the Company undertakes to evaluate how well a research and development project delivered on the proposal that is selected by the PGE R&D Committee.

Response:

R&D project leads are required to develop a final project report that specifies how the project performed against the original project benefits statements, and what value to customers was realized. If the project had significant value demonstrated, the business may decide to either expand the pilot or implement it as a normal business project.

September 15, 2021

To: Anna Kim
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 607
Dated September 2, 2021

Request:

Please provide a narrative description of the process the Company undertakes to evaluate the process by which research and development investments are selected.

Response:

R&D project proposals must demonstrate alignment with the overall approved corporate strategy, and each member of the R&D committee must have a clear understanding of the organization's strategy while successfully executing upon it. Criteria include some or all of the following:

1. Strategic Intent – How does the project align with the overall corporate strategy?
2. Strategic Plan – Does the sponsoring business unit have a strategic plan developed for the area of the business the project will influence? If so, how does the project align with the strategic plan?
3. Technology Assessment – What does the project do for the business unit?
4. Implementation – Does PGE have the technical competence and/or will PGE need to rely on vendors, partners (e.g., Electric Power Research Institute (EPRI), universities, other utilities), or contractors? What role will external support play in the project?

September 15, 2021

To: Anna Kim
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 608
Dated September 2, 2021

Request:

Please provide a narrative that explains how PGE determines what R&D topics are best addressed by trade organizations and other groups where PGE pays only a proportional cost for R&D but gets full access to findings vs. R&D initiatives that PGE determines are best undertaken in-house at PGE.

Response:

Generally, PGE strives to participate in group-funded research whether with industry research organizations or with universities and national laboratories. Leveraging work with multiple interested organizations results in a greater depth and breadth of research versus conducting individual research. However, some research is very specific to our customers or with a certain research partner that justifies a single project. All projects are reviewed by PGE's R&D committee with this trade-off in mind. Many times, an individual project request will be redirected to collaborate with an effort by the Electric Power Research Institute (EPRI) or some other institution.

CASE: UE 394
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1700
REDACTED

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Eric Shierman. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1701.

Q. What is the purpose of your testimony?

A. My opening testimony discusses issues associated with the following topics relating to transportation electrification (TE):

- Schedule 150;
- Line extension allowances for TE projects;
- PGE's recovery on TE programs the Commission has approved; and
- PGE's recovery on TE programs the Commission has not approved

Q. How is your testimony organized?

A. My testimony is organized as follows:

SUMMARY OF RECOMMENDATIONS

Q. Please summarize the recommendations included in your opening testimony.

A. Staff recommends the Commission:

1. Find PGE's $2.613 million of deferred O&M from TE pilots prudent.[1]
2. Approve PGE's new Schedule 150 and its automatic adjustment clause.
3. Find $393 thousand in capital expenditures on TE-related line extension allowances prudent.
4. Permanently remove $212 thousand in capital expenditures on TE-related line extension allowances from the rate base.
5. Find $3.025 million in capital expenditures on the TriMet Pilot and the Electric Avenue Network prudent.
6. Permanently remove $368 thousand in capital expenditures from the rate base relating to the TriMet Pilot and the Electric Avenue Network.
7. Approve the recovery of $1.602 million of O&M in base rates for expenses related to PGE's workplace charging, the Fleet Electrification Make-Ready Pilot, and the Nonresidential Heavy-Duty Electric Vehicle Charging Program.
8. Remove $1.88 million in O&M for TE-related expenses from base rates.
9. Approve the addition of **[Begin Confidential]** [redacted] **[End Confidential]** in PGE labor costs to the UM 1938 deferral of Outreach and Technical Assistance.
10. Permanently remove $1.58 million in capital expenditures on Electric Island from the rate base.
11. Find **[Begin Confidential]** [redacted] **[End Confidential]** in capital expenditures on electric vehicles (EV) for PGE's fleet prudent.
12. Permanently remove $6.909 million in capital expenditures on EV charging sites for PGE's fleet from the rate base.

[1] All dollar figures in this testimony are rounded to the nearest thousand dollars. The exact values can be found in the supporting exhibits.

ISSUE 1. SCHEDULE 150

Q. What is Schedule 150?

A. PGE has proposed Schedule 150 to implement an automatic adjustment mechanism to recover expenses associated with transportation electrification pilots not otherwise included in rates. Schedule 150 also specifies that the Company will maintain a balancing account to accrue differences between the incremental costs associated with transportation electrification and the revenues collected under the schedule. This balancing account will accrue interest at the Commission-authorized rate for deferred accounts.

Q. Does Staff support PGE's proposed Schedule 150, and if so, why?

A. Yes. Staff supports PGE's proposed Schedule 150 and its automatic adjustment clause (AAC) because this tariff will be an efficient means of collecting and tracking TE costs.

Q. Has Staff always supported an AAC for TE costs?

A. No. PGE filed Schedule 150 in February 2019.[2] Staff opposed the filing at that time and PGE ultimately withdrew it.[3]

Q. Why does Staff support an AAC now?

A. Staff has changed its position on PGE's proposed cost recovery mechanism due to relatively recent Commission actions and ongoing discussions with the Company. First, the Commission has since issued Order No. 20-147 that allows for the deferral of capital expenditures.[4] PGE's Schedule 150 initially

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2 PGE Advice No. 19-05.
3 *See* Docket No. ADV 292, OPUC Staff, Staff Report, April 18, 2019, p 1.
4 *See* Docket No. UM 1909, OPUC, Order No. 20-147, April 30, 2020, p 1.

included capital expenditures, and that violated the Commission's prior decision in Order No. 18-423 in effect in 2019.[5] Second, progress in UM 2165 causes Staff to believe the other issues around an earnings review and prudence review of these expenditures can be managed through modifications to the TE planning process.

Q. What costs does PGE seek recovery of with Schedule 150 in this proceeding?

A. PGE seeks to recover $2.613 million of deferred O&M from TE pilots.

Q. Is this amount of O&M that PGE seeks recovery for in deferrals reasonable?

A. Yes, according to PGE's response to Bench Request No. 2, the balance of PGE's tracking accounts, as of July 31, 2021, was $1,187 million. The added amount of $1,426 million that PGE seeks to recover through Schedule 150 is consistent with the forecasts PGE has filed in UM 1938 and UM 2003 that the Commission has approved.[6] This will be fully amortized in one year. Staff recommends the Commission find the $2.613 million in deferred O&M prudent.

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[5]. *See* Docket No. UM 1909, OPUC, Order No. 18-423, October 29, 2018, p 2.
[6] *See* Docket No. UM 1938, OPUC Staff, Staff Report, October 9, 2020, p 6.
See Docket No. UM 2003, OPUC Staff, Staff Report, April 23, 2021, p 4.

ISSUE 2. LINE EXTENSION ALLOWANCES FOR TE PROJECTS

Q. What is a line extension allowance?

A. When a customer requests service, the Company may be required to add facilities to reach the customer's location.[7] Each utility is authorized to provide customers a line extension allowance that covers a portion of the costs associated with the extension. Costs for new connections that are equal to or less than the line extension allowance are treated as the utility's costs and recovered through general rates. If the line extension allowance does not cover all the costs incurred to add facilities to the customer's location, the remaining portion of the cost is paid for by the customer seeking to connect.

Q. Are line extension allowances part of a TE program?

A. No. PGE's line extension rules are a cost sharing framework for many types of customers found in PGE's Schedule 300 and are not an element of approved TE programs under ORS 757.357.

Q. What costs for customer line extensions on TE projects does PGE seek to recover in this proceeding?

A. PGE includes a total of $605 thousand in capital expenditures in its rate base for TE-related line extension projects.

Q. Were all these expenditures reasonable?

A. No. Staff has engaged in analysis and has concluded that PGE used unreasonably high load forecasts for some projects in determining the line extension allowance.

[7] OAR 860-021-0045(1).

Q. Is the forecasting methodology used by PGE to forecast load of TE customers reasonable?

A. Yes. PGE currently uses two methodologies to forecast a site's load.[8] One method estimates the number of hours in a year the site could be used to recharge electric vehicles and multiplies this estimate by the demand factor (DF) of the load during those hours (Limited Hours Method). The other method multiplies the site's electric vehicle charger nameplate demand capacity by the 8,760 hours in a year and multiplies this amount by the DF of the site for the entire year (All Hours Method).

Q. What is a DF and how does PGE use it in its methodology?

A. A DF is the percentage of maximum potential load (kWh) the customer is expected to use during a certain time period. In PGE's load forecasting for line extension allowances, the time period is either a limited number of hours in a year (Limited Hours Method) or all the hours in a year (All Hours Method), depending on which of the two methods is chosen.

Q. How reasonably did PGE apply the Limited Hours Method in its analysis?

A. PGE's use of the Limited Hours Method was reasonable, except for one site, a **[Begin Confidential]** [redacted] **[End Confidential]**. In that instance, PGE used an estimate of the hours of use that was unreasonably high.

Q. How do you know it was unreasonably high?

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8 Staff/1706, Shierman/2 (PGE response to OPUC DR 738).

A. In a previous docket concerning line extensions for TE customers (ADV 1149), PGE's assumption about the hours of use for **[Begin Confidential]** [redacted] **[Begin Confidential]** was based on observations of this customer. In ADV 1149, PGE indicated this customer had **[Begin Confidential]** [redacted] **[End Confidential]** hours a day of use. PGE assumed **[Begin Confidential]** [redacted] **[End Confidential]** hours a day to calculate the load forecast for this customer's line extension allowance.[9]

Q. How did Staff adjust the allowance for this transit depot?

A. Staff used the hours a day of use PGE assumed for this kind of customer in ADV 1149, which reduced the line extension allowance.

Q. How reasonably did PGE apply the All Hours Method in its analysis?

A. Every time PGE used the All Hours Method for a TE project the Company used an unreasonably high DF.

Q. What is a reasonable DF for the All Hours Method?

A. Every site that PGE used the All Hours Method for was a public charging site. A reasonable DF for a public charging site using the All Hours Method is 0.08 (8 percent). This value is derived from 2018 data from PGE's Electric Avenue World Trade Center (WTC) site.

Q. Why not use an average from multiple sites?

A. That may be preferable, but PGE was unable to provide nameplate capacity data for public charging sites in the Company's service territory.[10]

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9 Staff/1708, Shierman Cells M466:M489 in the sheet titled "Assump".
Staff/1702, Shierman Cell M13 in the sheet titled "M2668959".

10 Staff/1706, Shierman 5, (PGE Response to OPUC DR 737).

Q. How does Staff know an All Hours Method DF of 0.08 is not unreasonably low?

A. For two reasons. One, PGE's WTC site was a well-established charging site that, for the first eleven months in 2018, provided electricity at no cost to EV operators. Two, when PGE uses the Limited Hours Method on public charging sites, this result is convertible to the All Hours Method for comparison. PGE's equivalent All Hours Method DFs for public charging sites range from 0.04 to 0.05.[11] For these two reasons, Electric Avenue's All Hours DF of 0.08 is likely higher than an average of other public charging sites.

Q. How did Staff adjust the allowance for these public charging sites with unreasonably high All Hours Method DFs?

A. Staff changed the DF PGE used to 0.08, which correspondingly reduces the amount of the line extension allowance.

Q. Did Staff make any additional adjustments?

A. Yes. PGE has lost documentation of three sites' load forecasts. Staff applied the same percentage adjustment to these three sites as Staff applied to the site with the highest All Hours Method DF.[12]

Q. What are Staff's total adjustments?

A. Staff recommends that the Commission find $393 thousand in capital expenditures on TE-related line extension allowances to be prudent. Staff recommends $212 thousand in capital expenditures on TE-related line

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11 Staff/1702, Shierman Cell K7 in the sheet titled "M2514850".
Staff/1702, Shierman Cell L7 in the sheet titled "M2768915".

12 Staff/1702, Shierman Cells E7, E19, and E21 in the sheet titled "Summary Table".

extension allowances be permanently removed from the rate base. The calculations for this adjustment are provided in Exhibit Staff/1702.

ISSUE 3. RECOVERY ON TE PROGRAMS THE COMMISSION HAS APPROVED

Q. What TE programs have the Commission approved?

A. The Commission has approved Outreach and Technical Assistance, TriMet Pilot, Electric Avenue Network, PGE's workplace charging, Schedule 8 Residential Electric Vehicle Charging Pilot, Schedule 52 Nonresidential Electric Vehicle Charging Rebate Pilot, Schedule 56 Fleet Electrification Make-Ready Pilot, and Schedule 53 Nonresidential Heavy-Duty Electric Vehicle Charging Program.[13]

Q. Is the Electric Vehicle Pole Charging Demonstration Project a Commission-approved TE program?

A. No. Funding for this TE-related research project has come from PGE's R&D budget in the past. It is now being funded by Clean Fuels Program credits, and the Company has not submitted a program application under OAR 860-087-0030.

Q. What Commission-approved TE programs had capital expenditures?

A. TriMet Pilot, Electric Avenue Network, and PGE's workplace charging.

Q. How much is PGE seeking recovery for from Commission-approved TE program capital expenditures in this proceeding?

[13] *See* Docket No. UM 1811, OPUC, Order No. 19-385, November 7, 2019, p 4.
See Docket No. UE 335, OPUC, Order No. 19-129, April 12, 2019, p 1.
See Docket No. ADV 1151, OPUC, Advice Letter, October 20, 2020, p 1.
See Docket No. ADV 1155, OPUC, Advice Letter, December 15, 2020, p 1.
See Docket No. ADV 1161, OPUC, Advice Letter, June 1, 2021, p 1.
See Docket No. UE 389, OPUC, Order No. 21-195, June 16, 2021, p 1.

A. PGE seeks to recover $3.392 million in capital expenditures from the TriMet Pilot and the Electric Avenue Network. This summation can be found in Exhibit Staff/1703. To derive that total, Staff added the amounts from PGE's response to OPUC DR 746. Staff also removed capital expenditures on TE-related projects that were not Commission-approved. Staff will go into more detail on the unapproved capital expenditures in Issue 4.

Q. Does Staff find that these are prudently incurred capital expenditures?

A. Staff finds that most of these capital expenditures were prudently incurred. However, Staff finds that PGE overspent by $5 thousand on the TriMet Pilot and $362 thousand on the Electric Avenue Network.

Q. What set the limit for prudent spending?

A. Commission Order 19-385 established maximum spending levels on these pilots.[14]

Table 1: Maximum Allowable Costs by Program ($000's)

	Maximum Allowable Costs		
	O&M	Overnight Capital Cost	Total
Outreach and Technical Assistance	480	-	480
TriMet Pilot	-	625	625
Electric Avenue Network*	2,787	2,400	5,187
Residential Home Charger Pilot	-	-	-
Pilot Evaluation	580	-	580
Total	3,847	3,025	6,872

* If federal tax credits are available, allowable decrease based on federal tax credits received.

[14] *See* Docket No. UM 1811, OPUC, Order No. 19-385, November 7, 2021, p 9.

Q. What adjustment to capital expenditures on the TriMet Pilot and Electric Avenue Network does Staff recommend?

A. Staff recommends that the Commission find $3.025 million in capital expenditures on the TriMet Pilot and Electric Avenue Network prudent and that $367 thousand be permanently removed from the rate base.

Q. Is PGE seeking recovery of costs for its workplace charging?

A. Yes, but new capital costs are beyond the scope of Staff/1700. These capital costs are covered by Staff's review of facility projects in Staff/200. However, PGE does report O&M for its workplace charging sites through FERC Account 908 as a TE expense and Staff has reviewed that O&M in this Staff/1700 testimony.

Q. How much O&M is PGE seeking recovery for in base rates from Commission-approved TE programs in this proceeding?

A. PGE seeks to recover $3.482 million of O&M in base rates.

Q. Is the amount in base rates reasonable?

A. No. That O&M number goes significantly beyond the $1.602 million the Commission has approved. In addition to PGE's workplace charging, the Commission has approved two TE programs to recover O&M through base rates: the Schedule 56 Fleet Electrification Make-Ready Pilot and the Schedule 53 Nonresidential Heavy-Duty Electric Vehicle Charging Program. The program application in ADV 1261 set the 2022 budget for the Fleet

Electrification Make-Ready Pilot at $691 thousand. This is the sum of the non-capital expenditure figures below.[15]

Table 3: Pilot Budget ($)

	2021	2022	2023	2024	2025	Total
Capex	65,818	1,053,233	2,749,584	2,831,731	-	6,700,366
O&M	204	1,922	5,772	9,554	9,739	27,192
Fleet Planning	75,000	50,000	25,000	-	-	150,000
Administration	339,750	488,640	488,640	280,500	10,800	1,608,330
Marketing	75,000	50,000	25,000	-	-	150,000
Evaluation	40,000	100,000	65,000	80,000	120,000	405,000
Total	**595,772**	**1,743,795**	**3,358,996**	**3,201,786**	**140,539**	**9,040,888**

For the other TE programs that the Commission approved to recover O&M in base rates, at the March 9, 2021 Public Meeting, Staff recommended the Commission suspend and investigate PGE's proposed Nonresidential Heavy-Duty Electric Vehicle Charging Program in ADV 1239. Staff's recommendation was based in part on the lack of information in the program application. During the subsequent investigation in UE 389, PGE shared a financial analysis projecting O&M in 2022 to be **[Begin Confidential]** [redacted] **[End Confidential]** These two approved budgets for O&M and PGE's forecasted O&M in the test year for its workplace charging infrastructure total $1.602 million.[16]

Q. What adjustment does Staff recommend?

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[15] *See* Docket No. ADV 1261, PGE, Fleet Electrification Make-Ready Pilot Proposal, April 20, 2021, p 16.

[16] Staff/1709, Shierman Cell O297 in the sheet titled "Calc".

A. Staff recommends the Commission approve TE-related recovery of $1.602 million of O&M in base rates and that $1.88 million be removed from PGE's proposed TE O&M expense.

ISSUE 4. RECOVERY OF TE PROGRAMS THAT THE COMMISSION HAS NOT APPROVED

Q. Is PGE seeking recovery of TE spending the Commission has not approved?

A. Yes. The Company is seeking recovery for spending on Electric Island and the electrification of PGE's own fleet.

Q. Does Staff believe this automatically makes these costs unrecoverable?

A. No. The absence of Commission approval as a TE program means the expenditures were not authorized under the statute that establishes different standards for TE expenditures.[17] In the absence of that approval, a TE investment may still have merit under the Commission's prudency standard, i.e. if a reasonable person risking a firm's own capital in a competitive market would have made the investment.[18] Therefore, Staff has reviewed Electric Island as a distribution system investment and the procurement of EVs for PGE's fleet as the general management of the Company's fleet, applying prudency review.

Q. What is Electric Island?

A. Electric Island is a joint project between PGE and Daimler Trucks North America (Daimler) to build a public charging station that can refuel heavy-duty electric vehicles at a charging capacity of 1 MW. PGE provided these services without a tariff in place.[19]

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17 ORS 757.357.
18 *See* Docket No. UG 132, OPUC, Order No. 99-697, November 12, 1999, p 52.
19 *See* Docket No. ADV 1239, OPUC Staff, Staff Report, March 1, 2021, pp 4-7.

Q. Was Electric Island authorized under Schedule 53, PGE's Nonresidential Heavy-Duty Electric Vehicle Charging Program?

A. No. PGE executed a contract with Daimler on September 15, 2020, committing itself to make these expenditures before the Commission approved Schedule 53 nine months later. Tariffs cannot apply retroactively to an investment the utility already made.[20] Therefore, Schedule 53 does not apply to the expenditures PGE made on Electric Island prior to the approval of Schedule 53. Staff recommended the Commission approve Schedule 53 at the June 15, 2021 Public Meeting because the program offers needed support to heavy-duty EVSE sites that are expected to follow the Electric Island project. The Electric Island project is qualitatively different than the future projects ratepayers will help fund through Schedule 53, which I will explain in more detail below.

Q. How does Staff expect future projects to be different than Electric Island?

A. Daimler made the decision to enter the heavy-duty EV market and develop charging at 1 MW before receiving subsidies from PGE.[21] In contrast, the expensive infrastructure needed to fuel heavy-duty EVs is expected to remain a significant barrier to fleet customers building charging stations with 1 MW demand capacity, particularly small and medium sized fleets.[22] Schedule 53 is available to fleet operators that may otherwise choose not to electrify their

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[20] ORS 757.210.

[21] Rogoway, Mike. *Daimler will convert Portland factory to make electric trucks* The Oregonian, April 24, 2019, p 1.

[22] NREL. *R&D Insights for Extreme Fast Charging of Medium and Heavy-Duty Vehicles* March 2020, p 10.

fleets without investment from PGE.[23] Staff recommended the Commission approve Schedule 53 with the expectation that future heavy-duty projects will have less free-ridership than subsidizing a manufacturer to build a site it already needed to build for the development and marketing of heavy-duty EV trucks.

Q. What are the prudence implications of providing services without a tariff?

A. It is inherently imprudent. A main tenant of the utility regulatory process in Oregon is that utilities are subject to rate regulation and required to file tariffs and schedules for all services they provide with the Commission.[24] This tenant is a statutory requirement in ORS 757.205(1). The reason that the legislature required tariffs to be on file is so that all activities by the utility are open to public inspection. This transparency seeks to prohibit public utilities from entering into discriminatory deals and preferential treatment for one customer over another.[25]

PGE did not file a tariff for its investment in Electric Island prior to making capital expenditures that the Company is now seeking to recover in this rate case. Staff's prudency analysis on the merit of the investment looks at whether this was an investment a reasonable person would make risking the firm's own capital in a competitive market. In a regulated market, it is not prudent for a utility to make an investment, with the intention to recover that investment from ratepayers, if that investment does not comply with the applicable rules and

23 *See* Docket No. ADV 1239, PGE, Supplemental Filing, March 4, 2021, Sheet No. 53-1.
24 *See Northwest Climate Conditioning Ass'n v. Lobdell*, 79 Or. App. 560 (1986) at p. 565.
25 *See* Docket No. ADV 1239, OPUC Staff, Staff Report, March 1, 2021, p 4-7.

laws that the utility must abide by. Therefore, this investment would not be prudent even if the investment benefitted ratepayers.

Q. Were any of the expenditures PGE made on Electric Island part of any TE expenditures that have been approved by the Commission?

A. Yes. PGE provided technical assistance to this project, which was approved in the Company's Outreach and Technical Assistance Pilot the Commission authorized in 2018.[26] In OPUC DR 425, Staff asked PGE to explain how the design and operational plan for Daimler's installation of heavy-duty charging changed as a result of PGE's creative input. PGE's reply described work consistent with the Outreach and Technical Assistance Pilot. Staff has included PGE's confidential response in Staff/1706 where this work is described in detail.[27]

Q. What adjustment does Staff recommend?

A. Staff recommends the Commission allow PGE to recover, through the Company's UM 1938 deferral, the full **[Begin Confidential]** [redacted] **[End Confidential]** in labor costs the Company incurred in 2020 providing technical assistance to the Electric Island project as an expense.[28] Staff also recommends that $1.58 million in capital expenditures be permanently removed from the rate base.[29]

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[26] *See* Docket No. UM 1811, OPUC, Order No. 19-385, November 7, 2019, p 11.
[27] Staff/1706, Shierman/7 (PGE response to OPUC DR 425).
[28] Staff/1706, Shierman/13 (PGE response to OPUC DR 419).
[29] Staff/1706, Shierman/20 (PGE response to OPUC DR 746).

Q. In Exhibit 500 of PGE's opening testimony, the Company mentions "goals to decarbonize PGE's fleet."[30] What does that statement refer to?

A. This is a reference to the electrification of PGE's own fleet by replacing vehicles with internal combustion engines (ICE) with electric vehicles (EV).

Q. Has the Commission authorized this fleet electrification plan as a TE program?

A. No. PGE has not filed a TE program application for the electrification of its own fleet.

Q. Has Staff discussed fleet electrification with PGE?

A. Yes. On July 22, 2020, Staff attended a PGE workshop to discuss the results of the Company's Fleet Decarbonization Study. Also, on September 22, 2020, Staff disseminated, for public comment, our Executive Order 20-04 Work Plan that included Staff's plan to include utility fleet planning for a transition to electricity or natural gas in future TE plans.[31]

Q. Does that imply Staff provided guidance to PGE that any costs incurred in electrifying the Company's fleet is a prudent investment?

A. No. It implies Staff is interested in getting the facts of fleet electrification before stakeholders and the Commission in future utility TE Plans and eventually into future Commission-approved TE programs, should the Commission ultimately decide to authorize such a program.

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[30] PGE/500, Bekkedahl – McFarland/13, line 13.
[31] OPUC Staff. *Oregon Public Utility Commission Executive Order 20-04 Work* Plans September 22, 2020, p 18.

Q. What are the costs for fleet electrification that PGE is seeking recovery for in this proceeding?

A. PGE is seeking recovery for $6.909 million in capital expenditures for fleet charging infrastructure construction, **[Begin Confidential]** [redacted] **[End Confidential]** for the price of purchasing **[Begin Confidential]** [redacted] **[End Confidential]** EVs, and $330,000 in O&M for the new charging infrastructure.[32]

Q. Does utility investment in fleet electrification without Commission approval as a TE program mean the Commission should automatically deny recovery of these costs?

A. No. PGE routinely purchases vehicles for its fleet on an ongoing basis. Staff's analysis looks at whether this was an investment a reasonable person would make risking the firm's own capital in a competitive market. Staff looked for what the Company knew and reasonably should have known at the time these investments were made.

Q. What did PGE know about the overall net benefit of electrifying the Company's fleet?

A. In OPUC DR 150, Staff asked PGE to share all research in the Company's possession on EV total cost of ownership (TCO) and all planning workpapers for the procurement of EVs for PGE's fleet. Of the documents PGE shared, two included net assessments of the electrification of the Company's fleet. **[Begin Confidential]** [redacted]

32 Staff/1706, Shierman/111 (PGE response to OPUC DR 901).
Staff/1705 Shierman E32 in the sheet titled "TCO".
Staff/1704 Shierman B25 in the sheet titled "Program OpEx".

[redacted] [End Confidential]

Q. Those were studies of electrifying PGE's entire fleet. Are any of PGE's actual EV purchases expected to give ratepayers net long-term savings on a per vehicle basis?

A. Yes. Staff performed a total cost of ownership (TCO) analysis on the EVs PGE purchased in comparison to their equivalent (ICE) vehicle. Of the **[Begin Confidential]** [redacted] **[End Confidential]** EV purchases, 20 show a favorable TCO if the costs of PGE's fleet charging sites are excluded.

[33] Staff/1706, Shierman/21 (PGE response to OPUC DR 150).
[34] Staff/1706, Shierman/34 (PGE response to OPUC DR 150).
[35] Staff/1707, Shierman/S4 in the sheet titled "Assump" (PGE response to OPUC DR 150).

Q. Why did Staff exclude the costs of PGE's fleet charging infrastructure from this analysis?

A. The EVs PGE purchased do not require a buildout of new charging infrastructure. In 2022, PGE will have 200 ports for its workplace charging sites spread across many of the Company's facilities. A reasonable person risking the firm's own capital in a competitive market would utilize them for fleet charging before building out more ports as this existing infrastructure sits idle at night and could be utilized for fleet charging.

Q. What adjustment does Staff recommend for the capital expenditures on EV procurement?

A. Staff does not recommend an adjustment. However, although not all of the EVs purchased presented ratepayers with a favorable TCO, they do collectively if looked at as a whole and if charging infrastructure costs are excluded. With a NPV savings of $24 thousand, the investment roughly breaks even over the TCO of comparable ICE vehicles due to PGE's access to wholesale power prices, Clean Fuels Program credits, and existing workplace charging infrastructure. Staff recommends the Commission find the entire **[Begin Confidential]** [redacted] **[End Confidential]** in capital expenditures on EV purchases prudent.

Q. Are the capital expenditures on fleet charging sites prudent?

A. No. The modest number of EVs that were prudently purchased don't need additional charging sites beyond what PGE already owns. Additionally, if PGE did need this additional infrastructure, the purchase of those EVs would not have been prudent. Staff would need to include that cost in the TCO of the vehicles.

Q. Might PGE need those new fleet charging sites for vehicles purchased in 2022?

A. That is unlikely, given how the number of workplace charging ports PGE will have in 2022 would still outnumber PGE's fleet EV count even if PGE were to double its number of EVs next year. Staff would like to see more information from PGE about what this new fleet charging construction is for. Staff gave the Company an opportunity to explain this investment in OPUC DR 723. PGE replied: "PGE is upgrading sites with new electrical service and underground infrastructure, where required by Fleet volume, to serve the Fleet as it is electrified. Site details vary by location and need, but ultimately, each PGE location will have EV make-ready infrastructure to enable new EVs and charging stations to be easily deployed as they come into service."[36] Staff finds this response insufficient to meet the Company's burden of persuasion that nearly seven million dollars needed to be invested in 2021 on new charging ports when PGE will already have 200 ports to choose from next year.

Q. What adjustment does Staff recommend?

A. Staff recommends the Commission permanently remove $6.909 million in capital expenditures on new fleet charging sites from the rate base. Staff's recommendation to remove the fleet charging sites' $330 thousand in O&M was captured in the O&M adjustment in Issue 3.

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[36] Staff/1706, Shierman/12.

CONCLUSION

Q. Please conclude with a summary of your recommendations.

A. Staff recommend the Commission:

1. Find PGE's $2.613 million of deferred O&M from TE pilots prudent.
2. Approve PGE's new Schedule 150 and its automatic adjustment clause.
3. Find $393 thousand in capital expenditures on TE-related line extension allowances prudent.
4. Permanently remove $212 thousand in capital expenditures on TE-related line extension allowances from the rate base.
5. Find $3.025 million in capital expenditures on the TriMet Pilot and the Electric Avenue Network prudent.
6. Permanently remove $368 thousand in capital expenditures from the rate base relating to the TriMet Pilot and the Electric Avenue Network.
7. Approve the recovery of $1.602 million of O&M in base rates for expenses related to PGE's workplace charging, the Fleet Electrification Make-Ready Pilot and the Nonresidential Heavy-Duty Electric Vehicle Charging Program.
8. Remove $1.88 million in O&M for TE-related expenses from base rates.
9. Approve the addition of **[Begin Confidential]** [redacted] **[End Confidential]** in PGE labor costs to the UM 1938 deferral of Outreach and Technical Assistance.
10. Permanently remove $1.58 million in capital expenditures on Electric Island from the rate base.
11. Find **[Begin Confidential]** [redacted] **[End Confidential]** in capital expenditures on electric vehicles (EV) for PGE's fleet prudent.
12. Permanently remove $6.909 million in capital expenditures on EV charging sites for PGE's fleet from the rate base.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1701

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATIONS STATEMENT

NAME:	Eric Shierman
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	MS Economics; Portland State University; Portland, Oregon BA Political Economy; Hillsdale College; Hillsdale, Michigan
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since June 2019 first as a Utility Analyst and for the past eleven months as a Senior Utility Analyst. I was previously employed by McCullough Research as a Research Associate for two years.

CASE: UE 394
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1702

Exhibits in Support
Of Opening Testimony

October 25, 2021

Confidential Staff Exhibit 1702

Is

Filed in electronic format

CASE: UE 394
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1703

Exhibits in Support
Of Opening Testimony

October 25, 2021

Staff Exhibit 1703

Is

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CASE: UE 394
WITNESS: ERIC SHIERMAN

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STAFF EXHIBIT 1704

Exhibits in Support
Of Opening Testimony

October 25, 2021

Staff Exhibit 1704

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CASE: UE 394
WITNESS: ERIC SHIERMAN

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STAFF EXHIBIT 1705

Exhibits in Support
Of Opening Testimony

October 25, 2021

Confidential Staff Exhibit 1705

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CASE: UE 394
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1706
REDACTED

Exhibits in Support
of
Opening Testimony

October 25, 2021

September 28, 2021

To: Eric Shierman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 738
Dated September 14, 2021

Request:

Referencing Attachment A of PGE's response to DR 427, please share the analysis that derived each site's combined factor, and please explain why:

a) M2206760, M2493753, M2514850, M2540673, M2575320, M2592820, M2684298, M2732401, M2733476, M2733478, M2768915, M2886696, M2894003, M2932283, M2957731, and M3001633 have combined factors of 1.
b) M2287965, M2638861, M2865157, M2924449, and M2974826 have combined factors of 0.49.
c) M2330041 has a combined factor of 0.1.
d) M2769397 has a combined factor of 0.5.
e) M2875615 has a combined factor of 0.38.

Response:

PGE used Demand Factors and Combined Factors as shown in the Table 1 below to determine/calculate the estimated annual kWh. These factors have been utilized for many years for all PGE projects and were based on data collected for similar services.

When determining the Adjusted kWh per year we use a combination of Load Summary (Connected load and Demand Factor), Combined Factor and/or Hours/Year of Usage.

Hours per year of usage can either be determined upfront (ex: 1.25 hours per day, 365 days/year = 455 hours per year) or the entire year is entered and then adjusted based on the Demand Factor and/or Combined factor calculations.

The Combined Factor is used based on types of services/businesses to determine estimated operating hours.

Table 1

Load Summary			
Load Type	Connect kw	Demand factors*	Estimated demand
Cooking	0	0.30	0
Lighting	0	0.90	0
Receptacles	0	0.10	0
Water heating	0	0.20	0
Electric heat	0	0.75	0
Air conditioning	0	0.75	0
Refrigeration	0	0.75	0
Motors	0	0.50	0
Computers	0	0.67	0
Welders	0	0.10	0
Elevators	0	0.10	0
Irrigation	0	0.75	0
Miscellaneous	0	0.50	0
Total est connected	0		

Combined Factor	
Public assembly	0.50
Offices	0.52
Food Stores	0.59
Hospitals & health care	0.62
Hotels & Motels	0.61
K-12 Schools	0.38
Medical offices	0.53
Misc commercial	0.49
Restaurants	0.57
Retail stores	0.55
Warehouses	0.56
Hobby Shop	0.10
Home Based Business	0.37

* If none of the above are appropriate, use a reasonable factor based on known operating hours. (Examples: large primary customer, irrigation, lighting, etc.)

PGE is in the process of evaluating our Demand Factors and Combined Factors to determine if adjustments might be needed for any of these values in these tables.

September 28, 2021

To: Eric Shierman
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 737
Dated September 14, 2021

Request:

Please update PGE's response to Staff IR 33 in ADV 1149 by adding all new EVSE sites that the Company has since discovered, and please add:

a. A description of each site using the categories in the financial analysis for fleets in UE 386 and public sites in ADV 1149. If a site doesn't fit one of these categories, please use a more precise description.
b. For sites that are also listed in Column A on the sheet titled "Summary Table" in Attachment A to PGE's response to Staff DR 427, the M#
c. The date the site began commercial operation
d. A note if the site has onsite generation
e. A note if the site has onsite storage
f. Each site's nameplate demand capacity
g. Each site's annual energy deliveries from the beginning of commercial operation to 2021 year-to-date.
h. Each site's hourly energy deliveries in an electronic Excel document from the first full hour of commercial operation to the latest hour interval data is available.
i. For sites that PGE owns the make-ready, a note explaining what pilot program the make-ready investment was made.

Response:

Please see Attachment 737-A, tab "A" for a list of 79 EVSE sites in PGE's service area, inclusive of active sites reported in ADV 1149 IR 33 (original response dated November 17, 2020 and first supplemental response dated March 26, 2021) and OPUC Data Request in Docket No. UE 394 Data Request No. 148. This list was developed in response to a series of specific Commission requests and is not a comprehensive list of all EVSE sites in PGE's service area.

a. Attachment 737-A, tab "A", column J, provides an estimated description of the type of charging at each site, based on the information available to PGE. As previously reported to OPUC, only one site in this data set corresponds to a site category modeled in UE 386 or ADV 1149. Please see the list below for examples of some of the challenges with categorization of sites:

1. Majority of sites listed in Attachment 737-A, do not have a separately metered EV charging station. Because their load is combined with non-EV load, it makes them ineligible for the programs proposed in UE 386 or ADV 1149.
2. A significant portion of the remaining sites are public Direct Current fast charging sites, which were similarly ineligible for the programs proposed in UE 386 or ADV 1149.
3. Categorizing sites accurately requires insight into the number of EVSE at a site, the charging rating (kW) of each EVSE, and the site access (employees, public, fleet, etc.). PGE has obtained some of this data from a third-party data platform called PlugShare; however, PGE notes that PlugShare data is crowd-sourced and can be difficult to interpret consistently. Further, PlugShare is a site for EV drivers to find public charging, therefore data is typically unavailable for non-public sites such as employee-only and/or fleet charging sites.
4. The categories developed for the financial models in UE 386 and ADV 1149 were not intended to be comprehensively representative of all possible eligible customer scenarios; rather, they were intended to represent a range of potential configurations for modeling purposes.

b. See Attachment 737-A, tab “A”, column E.
c. PGE does not have insight into the date when third-party EVSE sites began commercial operation. Even for sites where PGE owns the EVSE and/or the make-ready infrastructure, charger installation, commissioning and testing periods make it challenging to identify a single “commercial operation” date. For consistency, PGE has provided the Service Point Installation Date for separately metered EVSE sites. In PGE’s experience, this date can be several months from the date when site construction is complete and EVSE are ready for charging.
d. PGE identified one site with grid-connected generation among the 37 sites that are separately metered. PGE does not have insight into whether any sites have non-connected onsite generation. See Attachment 737-A, tab “A”, column F.
e. PGE did not identify any sites with grid-connected storage among the 37 sites that are separately metered. PGE does not have insight into whether any sites have non-connected onsite energy storage.
f. PGE has provided connected kW for the six sites that are enrolled in PGE programs (see Attachment 737-A, tab “A”, column K). Aside from these sites, PGE does not have insight into the nameplate charging capacity at third-party operated sites. For public charging sites, some data is available from PlugShare and PGE has, with reservations, used this data in the past to estimate site demand capacity. However, PGE has ended this practice for the following reasons:
   1. PGE discovered inconsistencies in our interpretation of the crowd-sourced third-party data set, with no reasonable method to resolve these inconsistencies without additional information.
   2. PGE found it impossible to match the third-party data set to our internal records.
   3. PGE finds it unreliable to sum the PlugShare-reported nameplate capacity of EVSE at a site to calculate overall demand capacity of a site.
   4. PlugShare data is typically unavailable for non-public sites such as employee-only or fleet charging sites, rendering the data set incomplete and of limited business value.
g. Please see attachment 737-A, tab “B”, for 37 sites which are separately metered.

h. Please see attachment 737-A, tab “C”, for 37 sites that are separately metered. The data covers the time period from mid-2018 (or the service point installation date, whichever is later) to present. PGE switched meter data management systems in mid-2018, and data from the prior system is not accessible in a format that allows for combined analysis across the two data sets.
i. Please see attachment 737-A, tab “A”, column G. Sites marked “Transit Pilot” and “Heavy-Duty EV Charging Demonstration” have PGE-owned make-ready infrastructure. Sites marked “Electric School Bus Fund” have customer-owned make-ready infrastructure.

[redacted]

[redacted]

OPUC DR 746 - TE Expenditures in Rate Case Filing

Program	Charge	Month	Amount
Electric Island	Flagging Services	202002	$ 197.50
Electric Island	Other Outside Services	202010	$ 543,901.00
Electric Island	Other Outside Services	202101	$ 651,824.00
Electric Island	Other Taxes & Governmental Fees	202006	$ 1,159.84
Electric Island	Accrual	202009	$ 543,900.00
Electric Island	Accrual	202010	$ (543,900.00)
Electric Island	Accrual	202012	$ 619,324.00
Electric Island	Accrual	202101	$ (619,324.00)
Electric Island	AFUDC debt charge	202001	$ 0.87
Electric Island	AFUDC debt charge	202002	$ 7.06
Electric Island	AFUDC debt charge	202003	$ 26.08
Electric Island	AFUDC debt charge	202004	$ 42.24
Electric Island	AFUDC debt charge	202005	$ 42.45
Electric Island	AFUDC debt charge	202006	$ 55.28
Electric Island	AFUDC debt charge	202007	$ 57.12
Electric Island	AFUDC debt charge	202008	$ 62.98
Electric Island	AFUDC debt charge	202009	$ 63.45
Electric Island	AFUDC debt charge	202010	$ 1,124.84
Electric Island	AFUDC debt charge	202011	$ 2,194.08
Electric Island	AFUDC debt charge	202012	$ 2,187.92
Electric Island	AFUDC debt charge	202101	$ 2,823.30
Electric Island	AFUDC debt charge	202102	$ 3,413.62
Electric Island	AFUDC debt charge	202103	$ 3,416.11
Electric Island	AFUDC equity charge	202001	$ 1.75
Electric Island	AFUDC equity charge	202002	$ 14.23
Electric Island	AFUDC equity charge	202003	$ 52.27
Electric Island	AFUDC equity charge	202004	$ 65.84
Electric Island	AFUDC equity charge	202005	$ 58.06
Electric Island	AFUDC equity charge	202006	$ 156.34
Electric Island	AFUDC equity charge	202007	$ 113.38
Electric Island	AFUDC equity charge	202008	$ 124.56
Electric Island	AFUDC equity charge	202009	$ 122.36
Electric Island	AFUDC equity charge	202010	$ 2,197.43
Electric Island	AFUDC equity charge	202011	$ 4,263.40
Electric Island	AFUDC equity charge	202012	$ 4,293.31
Electric Island	AFUDC equity charge	202101	$ 5,344.42
Electric Island	AFUDC equity charge	202102	$ 6,741.70
Electric Island	AFUDC equity charge	202103	$ 6,741.03
Electric Island	CABLE, 600V, 750 KCMIL, AL, QU	202003	$ 4,821.26
Electric Island	Construction Overhead	202001	$ 278.00
Electric Island	Construction Overhead	202002	$ 1,595.91
Electric Island	Construction Overhead	202003	$ 2,282.42
Electric Island	Construction Overhead	202004	$ 1,446.85

Electric Island	Construction Overhead	202007	$ 2,074.27
Electric Island	Construction Overhead	202010	$ 561,011.63
Electric Island	Employee Benefits Overhead	202001	$ 126.78
Electric Island	Employee Benefits Overhead	202002	$ 612.49
Electric Island	Employee Benefits Overhead	202003	$ 788.63
Electric Island	Employee Benefits Overhead	202004	$ 24.57
Electric Island	Employee Benefits Overhead	202005	$ (19.16)
Electric Island	Employee Benefits Overhead	202006	$ 47.85
Electric Island	Employee Benefits Overhead	202007	$ 32.51
Electric Island	Employee Benefits Overhead	202008	$ (1.82)
Electric Island	Employee Benefits Overhead	202009	$ 0.16
Electric Island	Employee Benefits Overhead	202010	$ (8.34)
Electric Island	Employee Benefits Overhead	202011	$ 19.49
Electric Island	Employee Benefits Overhead	202012	$ (2.00)
Electric Island	Employee Benefits Overhead	202101	$ 297.37
Electric Island	Employee Benefits Overhead	202102	$ 201.09
Electric Island	Employee Benefits Overhead	202103	$ 51.02
Electric Island	Employee support Offset	202001	$ 2.22
Electric Island	Employee support Offset	202002	$ 16.20
Electric Island	Employee support Offset	202003	$ 24.41
Electric Island	Employee support Offset	202004	$ 6.15
Electric Island	Employee support Offset	202005	$ 0.43
Electric Island	Employee support Offset	202006	$ 3.00
Electric Island	Employee support Offset	202007	$ (1.35)
Electric Island	Employee support Offset	202008	$ 0.55
Electric Island	Employee support Offset	202009	$ (0.39)
Electric Island	Employee support Offset	202010	$ (0.50)
Electric Island	Employee support Offset	202011	$ 0.92
Electric Island	Employee support Offset	202012	$ (0.23)
Electric Island	Employee support Offset	202101	$ 16.54
Electric Island	Employee support Offset	202102	$ (3.33)
Electric Island	Employee support Offset	202103	$ 0.79
Electric Island	Flagging Services	202002	$ 121.05
Electric Island	Incentives Overhead	202001	$ 14.45
Electric Island	Incentives Overhead	202002	$ 92.47
Electric Island	Incentives Overhead	202003	$ 26.58
Electric Island	Incentives Overhead	202004	$ 24.87
Electric Island	Incentives Overhead	202005	$ 12.40
Electric Island	Incentives Overhead	202006	$ 5.22
Electric Island	Incentives Overhead	202007	$ 12.66
Electric Island	Incentives Overhead	202008	$ 7.77
Electric Island	Incentives Overhead	202009	$ (220.89)
Electric Island	Incentives Overhead	202010	$ 224.44
Electric Island	Incentives Overhead	202011	$ 5.69
Electric Island	Incentives Overhead	202012	$ 57.70
Electric Island	Incentives Overhead	202101	$ 69.00
Electric Island	Incentives Overhead	202102	$ (2.23)

Electric Island	Incentives Overhead	202103	$	56.70
Electric Island	Injuries Overhead	202001	$	16.15
Electric Island	Injuries Overhead	202002	$	105.01
Electric Island	Injuries Overhead	202003	$	137.66
Electric Island	Injuries Overhead	202004	$	10.50
Electric Island	Injuries Overhead	202005	$	(4.08)
Electric Island	Injuries Overhead	202006	$	31.12
Electric Island	Injuries Overhead	202007	$	9.41
Electric Island	Injuries Overhead	202008	$	(4.34)
Electric Island	Injuries Overhead	202009	$	4.18
Electric Island	Injuries Overhead	202010	$	(9.82)
Electric Island	Injuries Overhead	202011	$	6.76
Electric Island	Injuries Overhead	202012	$	(47.53)
Electric Island	Injuries Overhead	202101	$	32.79
Electric Island	Injuries Overhead	202102	$	30.82
Electric Island	Injuries Overhead	202103	$	25.26
Electric Island	Labor Allocation - Hourly OT	202001	$	0.05
Electric Island	Labor Allocation - Hourly OT	202002	$	0.24
Electric Island	Labor Allocation - Hourly OT	202003	$	0.44
Electric Island	Labor Allocation - Hourly OT	202004	$	0.12
Electric Island	Labor Allocation - Hourly OT	202005	$	(0.01)
Electric Island	Labor Allocation - Hourly OT	202006	$	0.01
Electric Island	Labor Allocation - Hourly OT	202008	$	0.05
Electric Island	Labor Allocation - Hourly OT	202009	$	(0.02)
Electric Island	Labor Allocation - Hourly OT	202010	$	0.02
Electric Island	Labor Allocation - Hourly OT	202011	$	0.01
Electric Island	Labor Allocation - Hourly OT	202012	$	0.01
Electric Island	Labor Allocation - Hourly OT	202101	$	0.18
Electric Island	Labor Allocation - Hourly OT	202102	$	0.18
Electric Island	Labor Allocation - Hourly OT	202103	$	(0.03)
Electric Island	Labor Allocation - ST Salary	202001	$	14.18
Electric Island	Labor Allocation - ST Salary	202002	$	82.59
Electric Island	Labor Allocation - ST Salary	202003	$	116.83
Electric Island	Labor Allocation - ST Salary	202004	$	12.42
Electric Island	Labor Allocation - ST Salary	202005	$	(18.48)
Electric Island	Labor Allocation - ST Salary	202006	$	10.40
Electric Island	Labor Allocation - ST Salary	202007	$	12.30
Electric Island	Labor Allocation - ST Salary	202008	$	0.45
Electric Island	Labor Allocation - ST Salary	202009	$	(1.04)
Electric Island	Labor Allocation - ST Salary	202010	$	1.99
Electric Island	Labor Allocation - ST Salary	202011	$	(5.49)
Electric Island	Labor Allocation - ST Salary	202012	$	1.74
Electric Island	Labor Allocation - ST Salary	202101	$	25.56
Electric Island	Labor Allocation - ST Salary	202102	$	20.25
Electric Island	Labor Allocation - ST Salary	202103	$	10.44
Electric Island	Labor Allocation-ST Hrly NonUn	202001	$	1.04
Electric Island	Labor Allocation-ST Hrly NonUn	202002	$	6.49

Electric Island	Labor Allocation-ST Hrly NonUn	202003	$	8.84
Electric Island	Labor Allocation-ST Hrly NonUn	202004	$	0.66
Electric Island	Labor Allocation-ST Hrly NonUn	202005	$	(0.68)
Electric Island	Labor Allocation-ST Hrly NonUn	202006	$	0.52
Electric Island	Labor Allocation-ST Hrly NonUn	202007	$	0.63
Electric Island	Labor Allocation-ST Hrly NonUn	202008	$	(0.24)
Electric Island	Labor Allocation-ST Hrly NonUn	202009	$	(0.28)
Electric Island	Labor Allocation-ST Hrly NonUn	202010	$	(0.04)
Electric Island	Labor Allocation-ST Hrly NonUn	202011	$	(0.38)
Electric Island	Labor Allocation-ST Hrly NonUn	202012	$	0.09
Electric Island	Labor Allocation-ST Hrly NonUn	202101	$	1.84
Electric Island	Labor Allocation-ST Hrly NonUn	202102	$	1.45
Electric Island	Labor Allocation-ST Hrly NonUn	202103	$	0.76
Electric Island	Labor Allocation-ST Hrly Union	202001	$	0.08
Electric Island	Labor Allocation-ST Hrly Union	202002	$	16.02
Electric Island	Labor Allocation-ST Hrly Union	202003	$	42.82
Electric Island	Labor Allocation-ST Hrly Union	202004	$	2.00
Electric Island	Labor Allocation-ST Hrly Union	202005	$	(9.55)
Electric Island	Labor Allocation-ST Hrly Union	202006	$	2.31
Electric Island	Labor Allocation-ST Hrly Union	202007	$	10.48
Electric Island	Labor Allocation-ST Hrly Union	202008	$	0.81
Electric Island	Labor Allocation-ST Hrly Union	202009	$	(1.11)
Electric Island	Labor Allocation-ST Hrly Union	202010	$	1.26
Electric Island	Labor Allocation-ST Hrly Union	202011	$	(4.38)
Electric Island	Labor Allocation-ST Hrly Union	202012	$	1.70
Electric Island	Labor Allocation-ST Hrly Union	202101	$	0.02
Electric Island	Labor Allocation-ST Hrly Union	202102	$	0.01
Electric Island	Labor Allocation-ST Temporary	202006	$	0.16
Electric Island	Labor Allocation-ST Temporary	202007	$	0.24
Electric Island	Labor Allocation-ST Temporary	202008	$	0.19
Electric Island	Labor Allocation-ST Temporary	202009	$	0.02
Electric Island	Labor Allocation-ST Temporary	202010	$	0.02
Electric Island	Labor Allocation-ST Temporary	202011	$	0.06
Electric Island	Labor Allocation-ST Temporary	202102	$	0.05
Electric Island	Labor Allocation-Union Hrly OT	202002	$	0.59
Electric Island	Labor Allocation-Union Hrly OT	202003	$	1.60
Electric Island	Labor Allocation-Union Hrly OT	202004	$	(0.28)
Electric Island	Labor Allocation-Union Hrly OT	202005	$	(0.33)
Electric Island	Labor Allocation-Union Hrly OT	202006	$	0.16
Electric Island	Labor Allocation-Union Hrly OT	202007	$	0.12
Electric Island	Labor Allocation-Union Hrly OT	202008	$	(0.15)
Electric Island	Labor Allocation-Union Hrly OT	202009	$	1.21
Electric Island	Labor Allocation-Union Hrly OT	202010	$	(0.17)
Electric Island	Labor Allocation-Union Hrly OT	202011	$	(0.09)
Electric Island	Labor Allocation-Union Hrly OT	202012	$	(0.08)
Electric Island	Labor Allocation-Union Premium	202006	$	0.03
Electric Island	Labor Allocation-Union Premium	202009	$	0.25

Electric Island	Labor Allocation-Union Premium	202010	$	(0.02)
Electric Island	Labor Allocation-Union Premium	202011	$	(0.03)
Electric Island	Labor Allocation-Union Premium	202012	$	(0.02)
Electric Island	Materials	202003	$	983.10
Electric Island	Materials	202004	$	94.06
Electric Island	Materials	202008	$	0.01
Electric Island	Materials	202009	$	(92.10)
Electric Island	Net Periodic Pension Cost	202001	$	6.99
Electric Island	Net Periodic Pension Cost	202002	$	42.95
Electric Island	Net Periodic Pension Cost	202003	$	53.14
Electric Island	Net Periodic Pension Cost	202004	$	11.25
Electric Island	Net Periodic Pension Cost	202005	$	(0.25)
Electric Island	Net Periodic Pension Cost	202006	$	2.36
Electric Island	Net Periodic Pension Cost	202007	$	16.05
Electric Island	Net Periodic Pension Cost	202008	$	0.76
Electric Island	Net Periodic Pension Cost	202009	$	0.62
Electric Island	Net Periodic Pension Cost	202010	$	3,419.17
Electric Island	Net Periodic Pension Cost	202011	$	1.46
Electric Island	Net Periodic Pension Cost	202012	$	(0.27)
Electric Island	Net Periodic Pension Cost	202101	$	11.50
Electric Island	Net Periodic Pension Cost	202102	$	10.35
Electric Island	Net Periodic Pension Cost	202103	$	2.01
Electric Island	Non PGE Labor Straight Time	202003	$	741.15
Electric Island	Non PGE Labor Straight Time	202004	$	787.20
Electric Island	Non-Labor Allocation	202001	$	10.82
Electric Island	Non-Labor Allocation	202002	$	131.61
Electric Island	Non-Labor Allocation	202003	$	249.27
Electric Island	Non-Labor Allocation	202004	$	(7.75)
Electric Island	Non-Labor Allocation	202005	$	(8.80)
Electric Island	Non-Labor Allocation	202006	$	3.57
Electric Island	Non-Labor Allocation	202007	$	41.00
Electric Island	Non-Labor Allocation	202008	$	4.20
Electric Island	Non-Labor Allocation	202009	$	(15.42)
Electric Island	Non-Labor Allocation	202010	$	2.53
Electric Island	Non-Labor Allocation	202011	$	(4.37)
Electric Island	Non-Labor Allocation	202012	$	4.35
Electric Island	Non-Labor Allocation	202101	$	10.02
Electric Island	Non-Labor Allocation	202102	$	18.59
Electric Island	Non-Labor Allocation	202103	$	3.85
Electric Island	Other Outside Services	202003	$	59.58
Electric Island	Other Outside Services	202004	$	1,396.25
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202001	$	0.03
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202002	$	0.18
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202003	$	0.25
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202004	$	0.03
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202005	$	0.01
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202007	$	0.07

Electric Island	OtherPostEmplBeneNonSvcCstLoad	202008	$	0.02
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202009	$	(0.01)
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202010	$	15.18
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202101	$	(0.70)
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202102	$	(0.61)
Electric Island	OtherPostEmplBeneNonSvcCstLoad	202103	$	(0.13)
Electric Island	OtherPostEmplBene-SvcCostLoad	202001	$	2.01
Electric Island	OtherPostEmplBene-SvcCostLoad	202002	$	12.50
Electric Island	OtherPostEmplBene-SvcCostLoad	202003	$	15.64
Electric Island	OtherPostEmplBene-SvcCostLoad	202004	$	0.64
Electric Island	OtherPostEmplBene-SvcCostLoad	202005	$	(0.41)
Electric Island	OtherPostEmplBene-SvcCostLoad	202006	$	0.93
Electric Island	OtherPostEmplBene-SvcCostLoad	202007	$	0.98
Electric Island	OtherPostEmplBene-SvcCostLoad	202008	$	0.35
Electric Island	OtherPostEmplBene-SvcCostLoad	202009	$	0.27
Electric Island	OtherPostEmplBene-SvcCostLoad	202010	$	0.07
Electric Island	OtherPostEmplBene-SvcCostLoad	202011	$	0.52
Electric Island	OtherPostEmplBene-SvcCostLoad	202012	$	(0.04)
Electric Island	OtherPostEmplBene-SvcCostLoad	202101	$	6.46
Electric Island	OtherPostEmplBene-SvcCostLoad	202102	$	5.74
Electric Island	OtherPostEmplBene-SvcCostLoad	202103	$	1.15
Electric Island	Payroll Taxes	202001	$	34.91
Electric Island	Payroll Taxes	202002	$	235.58
Electric Island	Payroll Taxes	202003	$	336.80
Electric Island	Payroll Taxes	202004	$	(6.47)
Electric Island	Payroll Taxes	202005	$	(35.64)
Electric Island	Payroll Taxes	202006	$	(1.22)
Electric Island	Payroll Taxes	202007	$	15.66
Electric Island	Payroll Taxes	202008	$	(6.09)
Electric Island	Payroll Taxes	202009	$	(41.77)
Electric Island	Payroll Taxes	202010	$	15.96
Electric Island	Payroll Taxes	202011	$	(15.59)
Electric Island	Payroll Taxes	202012	$	(4.54)
Electric Island	Payroll Taxes	202101	$	123.45
Electric Island	Payroll Taxes	202102	$	78.39
Electric Island	Payroll Taxes	202103	$	28.71
Electric Island	Pension Service Costs	202001	$	20.45
Electric Island	Pension Service Costs	202002	$	127.81
Electric Island	Pension Service Costs	202003	$	160.77
Electric Island	Pension Service Costs	202004	$	6.85
Electric Island	Pension Service Costs	202005	$	(4.16)
Electric Island	Pension Service Costs	202006	$	9.68
Electric Island	Pension Service Costs	202007	$	10.44
Electric Island	Pension Service Costs	202008	$	3.41
Electric Island	Pension Service Costs	202009	$	3.09
Electric Island	Pension Service Costs	202010	$	0.62
Electric Island	Pension Service Costs	202011	$	5.27

Electric Island	Pension Service Costs	202012	$ (0.32)
Electric Island	Pension Service Costs	202101	$ 63.45
Electric Island	Pension Service Costs	202102	$ 57.07
Electric Island	Pension Service Costs	202103	$ 11.46
Electric Island	Prof 4 inch undetermined amoun	202007	$ 3,800.00
Electric Island	Reclassification	202012	$ (568,689.08)
Electric Island	Storeroom Materials	202003	$ 352.94
Electric Island	Storeroom Materials	202004	$ 495.02
Electric Island	Storeroom Materials	202006	$ 0.02
Electric Island	Storeroom Materials	202008	$ 0.03
Electric Island	Storeroom Materials	202009	$ (0.17)
Electric Island	Storeroom Materials	202010	$ 0.01
Electric Island	Storeroom Materials	202012	$ 0.02
Electric Island	Straight Time Labor Hourly	202002	$ 688.40
Electric Island	Straight Time Labor Salary	202001	$ 313.87
Electric Island	Straight Time Labor Salary	202002	$ 934.19
Electric Island	Straight Time Labor Salary	202003	$ 1,245.41
Electric Island	Straight Time Labor Salary	202004	$ 191.62
Electric Island	Straight Time Labor Salary	202101	$ 746.56
Electric Island	Straight Time Labor Salary	202102	$ 740.54
Electric Island	Straight Time Labor Salary	202103	$ 246.85
Electric Island	Straight Time Labor Union	202002	$ 228.00
Electric Island	Straight Time Labor Union	202003	$ 1,211.78
Electric Island	Straight Time Labor Union	202006	$ 220.08
Electric Island	Travel to Daimler Testbed site	202004	$ 5.75
Electric Island	Vacation Overhead	202001	$ 51.51
Electric Island	Vacation Overhead	202002	$ 306.22
Electric Island	Vacation Overhead	202003	$ 443.10
Electric Island	Vacation Overhead	202004	$ 12.20
Electric Island	Vacation Overhead	202005	$ 61.45
Electric Island	Vacation Overhead	202006	$ (6.09)
Electric Island	Vacation Overhead	202007	$ 19.63
Electric Island	Vacation Overhead	202008	$ 0.44
Electric Island	Vacation Overhead	202009	$ 7.31
Electric Island	Vacation Overhead	202010	$ 4.90
Electric Island	Vacation Overhead	202011	$ 78.81
Electric Island	Vacation Overhead	202012	$ (97.13)
Electric Island	Vacation Overhead	202101	$ 186.59
Electric Island	Vacation Overhead	202102	$ 97.98
Electric Island	Vacation Overhead	202103	$ (9.00)
Electric Island	April-December 2021 Fcst in Filing	202104 - 202112	$ 307,069.91
Total			$ 1,580,105.71

CASE: UE 394
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1707

Exhibits in Support
Of Opening Testimony

October 25, 2021

Confidential Staff Exhibit 1707

Is

Filed in electronic format

CASE: UE 394
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1708

Exhibits in Support
Of Opening Testimony

October 25, 2021

Confidential Staff Exhibit 1708

Is

Filed in electronic format

CASE: UE 394
WITNESS: ERIC SHIERMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1709

Exhibits in Support
Of Opening Testimony

October 25, 2021

Confidential Staff Exhibit 1709

Is

Filed in electronic format

CASE: UE 394
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1800

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Steve Storm. I am a Senior Economist employed in the Rates, Finance, and Audit (RFA) Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1801.

Q. What is the purpose of your testimony?

A. I address a request for deferral of expenses and capital costs related to the retired Boardman coal-fueled plant (Boardman) that are currently included in the retail rates of Portland General Electric Company (PGE or Company). The Alliance of Western Energy Consumers (AWEC) and the Oregon Citizens' Utility Board (CUB) asked the Commission to order PGE to defer the Boardman capital costs and expenses in an application to defer filed in October 2020. The application was docketed as UM 2119.

CUB and AWEC filed a motion on October 7, 2021, to consolidate UM 2119 with this rate case. The motion to consolidate is still pending.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. BOARDMAN COSTS IN RATES

Q. What issue is raised in UM 2119?

A. The issue concerns revenues collected from customers in rates after Boardman's closure and prior to the effective date of rates resulting from UE 394. Specifically, the issue presented in AWEC's and CUB's deferral application in UM 2119 is whether amounts recovered in retail rates for Boardman-related costs after Boardman ceased to operate should be deferred and the deferral balance subsequently amortized in customer rates. Absent such a deferral and subsequent amortization, customers end up paying for Boardman-related costs when the plant is no longer providing benefits to customers; i.e., when Boardman is no longer used and useful.

Q. Please explain why this deferral may be necessary.

A. Boardman is a coal-fired plant that ceased operation in October of 2020. The plant was operating and was expected to operate during the 2020 Test Year for PGE's last general rate case, UE 335. Accordingly, current base rates include a return *on* PGE's Boardman investment, a return *of* PGE's Boardman investment (depreciation), Boardman's operation and maintenance (O&M) costs, and potentially other costs, including associated fees and taxes. Boardman's costs will remain in customer rates until the rate effective date for the proceeding at hand.

Q. Absent the deferral and amortization of the deferred balance proposed by AWEC and CUB, PGE benefits as a result of regulatory lag. Are there examples where regulatory lag associated with a generation plant being

either placed in service or removed from service has been addressed in the past?

A. Yes, and Staff provides an example of each below. PGE has used an automatic adjustment clause (AAC) that serves to eliminate regulatory lag associated with the Company's investment in new renewable generation facilities. This AAC is known as PGE's Schedule 122 Renewable Adjustment Clause (RAC).

Q. What was PGE's most recent use of Schedule 122?

A. The most recent use of Schedule 122 resulted from Docket No. UE 370, for recovery of costs associated with the PGE-owned portion of the Wheatridge wind generation facility.[1]

Q. What costs for the PGE-owned portion of the Wheatridge wind facility did PGE propose to recover in Schedule 122 RAC rates?

A. These included "PGE's share of Wheatridge's wind-related capital costs, production O&M costs, insurance and Administrative and General (A&G) expenses, property and payroll taxes, revenue-sensitive costs such as expense associated with uncollectible revenue and OPUC fees, and income taxes,"[2] as well as PGE's share of costs associated with certain other plant associated with its portion of the Wheatridge wind facility.[3]

[1] See; e.g., page 1 of Order 20-321 in UE 370.

[2] Exhibit Staff/100, Storm/9 lines 4-8 in UE 370, reflecting language at Exhibit PGE/100 Armstrong – Batzler/1. A PGE update to Schedule 122 rates also included net variable power cost (NVPC) savings attributable to the PGE-owned portion of Wheatridge. See Exhibit Staff/100, Storm/11 lines 1-4.

[3] See; e.g., Exhibit Staff/100, Storm/13 line 8 – Storm/14 line 14 in UE 370.

Q. Did PGE provide, in its initial UE 370 application, an estimated cost of its share of Wheatridge-wind and associated facilities its Schedule 122 rates were intended to recover?

A. Yes. PGE's estimated gross plant in service, as proposed in the Company's UE 370 application for initial cost recovery using its RAC Schedule 122, was "approximately $157.4 million, including allowance for funds used during construction (AFDC) and property taxes."[4]

Q. Is PGE recovering any costs associated with Boardman that are not in current customer base rates?

A. Yes. PGE is using its Schedule 145, described by the Company as an automatic adjustment clause, to "implement in rates the revenue requirement effect of the decommissioning expenses related to the Boardman power plant."[5] Use of Schedule 145 for such costs allows PGE to reduce—if not avoid completely—any regulatory lag associated with the recovery of these costs.

Staff notes that each example of AAC mechanisms above exists as the result of regulatory processes.

Q. Did AWEC and CUB provide an estimate of the costs that may be subject to the deferral application in this proceeding?

A. Yes. Their October 8, 2020 application acknowledges that they "do not currently have the information necessary to provide a precise accounting of the

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4 Exhibit Staff/100, Storm/31 lines 14-17 in UE 370, citing PGE/100 Armstrong – Batzler/16 in the same proceeding.

5 *See* the Fourteenth Revision of Sheet No. 145-1.

amount to be deferred…but estimate that the amount currently included in PGE's base rates is approximately $50 million."[6] AWEC and CUB later estimate that the deferral of revenues collected from such rates will result in a deferral balance of "approximately $90 million at the time of amortization."[7]

Q. Has Staff validated either of these values?

A. No, not at the time of this testimony.

Q. Should there be a limit on the amount of costs in current rates associated with a rate base investment that is no longer used and useful as proposed in AWEC and CUB's application that could be deferred and later amortized?

A. No. Staff understands the question to involve a deferral that is in effect until costs being recovered in current rates are eliminated as an outcome of a subsequent general rate case proceeding.

Staff advocates that there be no such limit and notes that a deferral in this context includes the capital costs of assets that are likely to be appreciably—if not fully—depreciated at the time of closure, whereas PGE's Schedule 122 will typically involve new renewable generation assets that have limited or no accumulated depreciation.

However, if a limit is established in the future associated with a generating facility and associated plant in rate base that ceases to operate

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6 *See* Docket No. UM 2119, AWEC and CUB's Application for Authorization of Deferral Accounting, October 8, 2020 at 4. Staff interprets AWEC and CUB's $50 million estimate as representing the annual revenue requirement associated with Boardman in base rates.

7 *See* Docket No. UM 2119, AWEC and CUB's Application for Reauthorization of Deferral Accounting, October 4, 2021 at 4.

between the rate effective dates of successive general rate cases, that limit should be of a magnitude no less than an easily conceivable maximum amount associated with the cost of renewable generation investments using a renewable adjustment clause mechanism such as PGE's Schedule 122. There should be recognizable equity not only in timely recovery or crediting of costs, but also in any limits placed upon such recovery or crediting.

Q. In their deferral application in UM 2119, what time do AWEC and CUB propose the deferral of Boardman costs to begin?

A. Their October 8, 2020 application requests that the Commission order the deferral to begin on the date Boardman ceases operation.[8]

Q. Does Staff know the interest rate AWEC and CUB applied to interim balances that result in their estimate of a $90 million deferral balance at the time amortization in rates is to begin?

A. No. As ALJ Lackey's UE 394 Procedural Conference Memorandum has rates resulting from UE 394 effective on May 9, 2022, the implied duration of AWEC and CUB's requested deferral is approximately 19 months.

Q. What does Staff recommend as the interest rate to be applied to any deferral balance resulting from the AWEC/CUB applications?

A. Staff believes that the Rate of Return (RoR) authorized in PGE's last general rate case, UE 335, should be applied to the deferral balance, which is a regulatory liability. Relative to a Commission Order approving deferral, the

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[8] *See* Docket No. UM 2119, AWEC and CUB's Application for Authorization of Deferral Accounting, October 8, 2020 at 5.

RoR should be applied to prior balances and as well as future balances; i.e., applied to balances over the period of deferral. This produces an equitable outcome between general rate case proceedings and Staff notes again this is an analog to how rates for new renewable generation resources are developed for use in Schedule 122.

Q. Does Staff support the request for deferral?

A. Yes. Staff supports a deferral that begins at the time Boardman ceased to operate. CUB and AWEC argue deferral is appropriate under ORS 757.259(2)(e), which specifies that the Commission may authorize deferral of "[i]dentifiable utility expenses or revenues, the recovery or refund of which the [C]ommission finds should be deferred in order to…match appropriately the costs borne by and benefits received by ratepayers" for "later incorporation in rates."[9]

As discussed in the deferral application, ordering the deferral will match the costs and benefits of the Boardman plant.[10] Customers no longer benefited from Boardman operations once the plant closed. It is appropriate that customers not be responsible for Boardman costs once it stopped providing benefits.

Staff considers the deferral of certain Boardman costs post-closure and use of the ensuing deferral balance resulting from Commission authorization of

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9 *Id.* at 3.
10 *Id*.

the requested deferral to reduce PGE’s revenue requirement in the proceeding at hand to be an equitable and pragmatic application of such a balance.

Q. Does Staff propose any alternative to using the deferral balance as of the rate effective date in this proceeding as a standalone reduction to revenue requirement in the proceeding at hand?

A. No. First, the ALJ has not—as of the time Staff developed this testimony—ruled on the proposed consolidation of UM 2119 into this proceeding. Additionally, Staff will investigate the impact of using the deferral balance as of the rate effective date in this proceeding as an offset to one or more existing regulatory assets, potentially including those represented by wildfire or ice storm damages deferral balances.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: STEVE STORM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1801

Witness Qualification Statement

October 25, 2021

WITNESS QUALIFICATION STATEMENT

NAME Steve Storm

EMPLOYER Public Utility Commission of Oregon

TITLE Senior Economist

ADDRESS 201 High Street SE, Suite 100
Salem, OR 97301

EDUCATION MBA; University of Oregon; Eugene, Oregon
AB (Economics); Harvard University; Cambridge, Massachusetts

EXPERIENCE I have been employed by the Public Utility Commission of Oregon since October 2018 as a Senior Economist. I was previously employed by the Commission as a Senior Economist 2007–2008, as the Program Manager of the Economic and Policy Analysis section 2008–2012, and as an Economist 4 2012–2013. My responsibilities have included performing as well as leading a team of analysts performing economic and financial research and providing technical support on a wide range of policy issues involving electric, natural gas, and telecommunications utilities. I have testified before the Commission on policy and technical issues in multiple dockets.

I have over 35 years of professional experience performing and directing the performing of economic, financial, and other quantitative analysis.

I was employed by NW Natural as a Senior Economist in its IRP team 2013–2018, where my responsibilities included customer and industrial load forecasting; performing cost of service and related financial analysis on a variety of infrastructure projects and alternatives; and preparing economic information for executive communications.

I was a self-employed financial planner for eight years following an 18 year career in management positions responsible for pricing and cost analysis; financial analysis, planning and management; and strategic planning in the publishing and telecommunications industries. I managed the pricing and cost accounting functions for Pacific Northwest Bell's Directory department and its successor company, US WEST Direct, for five years. I managed the departmental budgeting and management reporting functions at US WEST Direct for three years and had seven years management experience in capital budgeting, financial analysis, and strategic planning functions at US WEST Communications. I managed the corporate financial planning, analysis, and management reporting functions for one year at Electric Lightwave.

CASE: UE 394
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1900

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Rose Anderson. I am a Senior Economist employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1901.

Q. What is the purpose of your testimony?

A. My testimony evaluates Portland General Electric's (PGE or Company) proposed Schedule 146 for recovery of Colstrip revenue requirement.[1]

Q. How is your testimony organized?

A. My testimony is organized as follows:

1 PGE owns a twenty percent share of Colstrip units 3 and 4, for a total of 296 MW.

ISSUE 1. COLSTRIP SCHEDULE 146 NET PLANT BALANCE

Q. Please provide background and summary of PGE's proposal for Colstrip.

A. PGE proposes to recover "all identifiable Colstrip-related costs (both expense and capital related costs),"[2] which equals $55.9 million in isolated revenue requirement,[3] utilizing its Schedule 146 with certain updates. PGE's proposal would remove Colstrip from PGE's base rates and recover Colstrip costs only through updates to Schedule 146.[4]

PGE's proposed update to Schedule 146 clarifies three cost streams for Colstrip. Part A consists of the decommissioning revenue requirement. Part B consists of the depreciation revenue requirement. Part C consists of all other Colstrip revenue requirement, excluding transmission, Schedule 125 power costs, and Parts A and B.[5]

A balancing account would track the difference between forecast and actual decommissioning costs (Part A) and will accrue interest at the Company's authorized rate for deferred accounts.

Regarding Part B (depreciation), the tariff states that "[t]he Adjustment Rates will be updated annually to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 decommissioning revenue requirement and depreciation revenue requirement (Parts A and B)."[6]

2 PGE / 1200, Macfarlane – Tang / 49.
3 PGE / 200, Tooman – Batzler / 2.
4 PGE / 1200, Macfarlane – Tang / 49.
5 PGE / 1201, Macfarlane - Tang / 79-81.
6 PGE / 1201 – Macfarlane – Tang / 81.

However, PGE's testimony explains that "similar to the original design of Schedule 146…only the changes to Colstrip's operating life and decommissioning costs are allowed to update annually."[7] This indicated to Staff that the depreciation revenue requirement might not be updated annually, as suggested in the tariff.

Staff submitted discovery to reconcile these potentially contradictory statements. In response to Staff Data Request 603, PGE clarified that depreciation in Part B would only be updated if the expected operating life of the plant has changed. PGE stated that the Company does not plan to update the undepreciated capital plant balance (net plant balance) for Colstrip annually and would only update net plant balance if the forecasted economic life of Colstrip were to change from what was assumed in this proceeding. [8]

The tariff states that "remaining amounts" (Part C) can only be updated upon the removal of Colstrip from regulated service, or rate change requests effectuated through a separate docketed proceeding.[9]

Q. What is Staff's position on PGE's proposed Schedule 146?

A. Staff generally supports recovery of Colstrip's annual revenue requirement through a tariff that can be updated outside of a general rate case, which is consistent with the Commission's approach to other coal-fired resources.[10] Staff

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7 PGE / 1200, Macfarlane – Tang / 49.
8 Staff / 1902 (PGE's response to Staff DR 603).
9 PGE / 1201 – Macfarlane – Tang / 81.
10 See *e.g.* Order No. 10-478 (Boardman) and Order No. 17-235 (Valmy).

also supports PGE's proposal to maintain a balancing account to track the difference between forecast and actual Colstrip decommissioning costs, which is also consistent with prior Commission precedent.[11]

However, Staff is concerned that the tariff, as written, does not require the Company to update the net plant balance annually. Annual updates to net plant balance will benefit customers and should not harm the Company so long as any other Colstrip costs in Part C are also updated annually.

Staff also notes that tracking the difference between forecast and actual decommissioning costs in a balancing account in Part A requires an underlying deferral, to the extent that PGE seeks to amortize the ending plant balance at a future date.[12]

Q. Please explain how customers will be harmed if the net plant balance is not updated annually, concurrently with other Colstrip costs.

A. The utility earns a return on the net plant that is included in rate base. Rate base is generally updated at the time of a general rate case. The amount of net plant varies over time as the plant depreciates (decreasing net plant) and plant refurbishments are added (increasing net plant). Overall, however, general net plant declines over time. As the net plant declines, the Company generally benefits from regulatory lag associated with the delay in updating net plant balance until the next general rate case. This is because customers pay a rate

[11] *See e.g.* Order No. 12-235, page 1, and Order No. 17-235, page 4.
[12] *In re Idaho Power Co.*, OPUC Docket No. UE 316, Order No. 17-235, p. 9 (June 30, 2017).

of return on a greater amount of undepreciated capital (net plant) than if rates had been updated for accumulated depreciation.[13]

As noted before, regulatory lag typically provides the utility incentives to control costs, so while some costs are decreasing, other costs could be increasing. What matters from an overall rates perspective is the level of utility earnings. However, with a retiring large thermal plant such as Colstrip where PGE is a minority owner, PGE's ability to manage costs may be limited. In addition, the amount of new capital investment in the plant should begin to decrease naturally as the plant nears retirement. This means it is likely that the rate impacts of annual changes to net plant balance, especially at a plant undergoing accelerated depreciation such as Colstrip, are likely to be large in comparison to the annual level of capital investment at the plant. Thus, updating both net plant balance and other Colstrip costs annually is likely to benefit customers while allowing the Company the opportunity to recover costs and earn a reasonable return.

Q. Has the Commission approved an Automatic Adjustment Clause for a coal-fired plant that included an annual update to net plant?

A. Yes. In UE 316, the Commission approved a cost recovery mechanism for Idaho Power's Valmy plant, which included annual updates to Idaho Power's return on the undepreciated existing capital investment at Valmy until its end-of-life.[14,15]

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13 UM 2004/Joint Customer Group/100, Jenks-Hellman/21.
14 Order No. 17-235 at Appendix A, p. 7.
15 Advice No. 18-02. page 2.

Q. Are there other public policy reasons as to why the Company's proposed treatment should not be adopted?

A. Yes. A general policy goal of the State of Oregon is to remove coal costs from rates. It seems consistent to Staff that the Commission should remove coal costs from rates when those costs are no longer present. Therefore, as rate base declines for Colstrip, rates should also reflect the declining return on investment associated with the depreciated rate base. Doing so on an annual basis seems a reasonable way to accomplish that public policy goal. This treatment also aligns with accelerating the depreciation of a plant, which has occurred with Colstrip.

Q. Please explain Staff's position on using deferred accounting and a balancing account for decommissioning costs at Colstrip.

A. PGE's proposal to use a balancing account for Colstrip's decommissioning costs is reasonable. The use of deferred accounting is frequently discouraged by Staff because it typically removes the incentive for the Company to manage costs. However, the Colstrip plant is nearing its expected end of operating life, and decommissioning cost estimates may be updated from year to year as the plant is prepared to exit commercial operation. The opportunity to update decommissioning cost estimates annually and recover them precisely will help customer rates reflect the most up-to-date information and reduce the potential for customer rate shock. It will also help ensure customers do not pay more than the actual decommissioning costs of the plant. A balancing account is also consistent with the treatment of decommissioning costs for the Boardman plant through PGE's Schedule 145.

A deferral is necessary to allow for future ratemaking treatment associated with the balancing account balance. As such, Staff recommends that the Commission approve a deferral, to be reauthorized annually by PGE in order to track these costs. The Commission took the same approach in Idaho Power's recovery mechanism for its Valmy Plant.[16]

Q. What is Staff's recommendation regarding Schedule 146?

A. The Schedule 146 tariff language, and the Company's associated treatment of Colstrip revenue requirement, should require net plant balance to be updated any time that Part C of the tariff is updated, or annually, whichever occurs sooner. The following redline shows the language that Staff recommends:

> **DETERMINATION OF ADJUSTMENT AMOUNTS**
>
> The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 ~~decommissioning revenue requirement and depreciation~~ revenue requirement (Parts A ~~and~~, B, and C). ~~Any additional updates (Part C) to this schedule can only be made pursuant to 1) the removal of Colstrip from regulated service, or 2) rate change requests effectuated through a separate docketed proceeding as allowable through Oregon Revised Statutes and Oregon Administrative Rules (e.g., through a general rate case).~~

[16] Order No. 17-235, p. 9.

Staff also recommends that the Commission approve a deferral to track PGE's Colstrip decommissioning costs, to be reauthorized annually after application by PGE and approval by the Commission.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1901

Witness Qualifications Statements

October 25, 2021

WITNESS QUALIFICATION STATEMENT

NAME: Rose Anderson

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Resources and Planning Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION: Master of Science, Agriculture and Resource Economics, University of California Davis, Davis, CA

Bachelor of Arts, International Political Economy
University of Puget Sound, Tacoma, WA

EXPERIENCE: I have been employed at the Public Utility Commission of Oregon since September of 2016. My position is Senior Economist in the Energy Resources and Planning Division. I perform economic and policy analysis, including analysis of net present value revenue requirement and load forecasts, in Rate Cases and planning dockets. I have participated in OPUC rate cases including UE 319, UG 325, UG 344, and UE 374, and OPUC power cost dockets including UE 320, UE 323, UE 333, UE 335, and UE 390. Prior to working for the PUC I was a Research Associate at McCullough Research for two years. My responsibilities included economic analysis of energy markets and utilities.

CASE: UE 374
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1902

Exhibits in Support
Of Opening Testimony

October 25, 2021

September 15, 2021

To: Rose Anderson
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 603
Dated September 1, 2021

Request:

PGE's proposed Schedule 146 Tariff says, "The Adjustment Rates will be updated annually to reflect the subsequent year's change in the Colstrip Power Plant Units 3 and 4 decommissioning revenue requirement and depreciation revenue requirement (Parts A and B)."

Please explain whether Schedule 146, as proposed in PGE's initial filing, would update the undepreciated capital plant balance and associated return on investment for the Colstrip plant annually.

Response:

PGE only intends to update decommissioning costs in Schedule 146 on an annual basis (i.e., Part A of Schedule 146). PGE will update the accumulated depreciation in the annual updates if the forecasted Colstrip economic life changes from what was assumed in this rate case and thus changes the annual depreciation of the facility.

CASE: UE 394
WITNESS: JEAN-PIERRE BATMALE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2000

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Jean-Pierre Batmale. I am a Division Administrator employed in the Energy Resources and Planning Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/2001.

Q. What is the purpose of your testimony?

A. I testify regarding the activities and associated staffing levels by PGE around certain public policy areas and offer no specific adjustments, but rather support the adjustment proposed by Ms. Cohen regarding cost recovery for employees.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. BACKGROUND TO TRANSPORTATION ELECTRIFICATION AND FLEXIBLE LOAD AND DISTRIBUTION PLANNING

Q. What is the FOCUS of Staff's testimony?

A. This testimony is focused on the growth in expenditures around two public policy matters. Those matters are Transportation Electrification (TE) and a broad category Staff refers to as Flexible Load & Distribution Policy (FLDP). This testimony supports the recommendations of Ms. Cohen regarding a freeze on hiring through providing an assessment of the activities around TE and FLDP.

Q. What Is Flexible Load & Distribution Policy (FLDP)?

A. In the context of this rate case, Staff has created the umbrella term of FLDP to capture the activities across four interrelated policy areas. These policy areas are Distribution System Planning, Flexible Load Planning, Demand Response (DR) Programs, and Smart Grid Test Bed. PGE bundles the expenses of the two planning activities together in its accounting. PGE also bundles the expenses of DR programs and the Smart Grid Test Bed together. For the purposes of this testimony, Staff will either refer to these four topics as one set of activities, FLDP, or will differentiate them by their distinct names.

Q. Why is Staff focused on TE and FLDP?

A. Staff is focused on these TE and FLDP for three overarching reasons. First, they are poised to play a central role in the evolving utility business model. TE has the potential to both grow utility loads while also reducing greenhouse gas (GHG) and other local air pollutants. For the distribution system, utilities will need to continue to make strategic investments to harness the flexibility of demand to meet decarbonization and resiliency goals. Second, expenditures and associated activities in these two areas have grown rapidly in recent years and are poised to continue to grow at the same rate over the next decade. Third, these two areas play a large role in the Company's sustainability goals and in burnishing the brand image of PGE generally.[1]

Q. Can Staff provide a brief snapshot of TE and FLDP activities for context?

A. As of 2019 there were an estimated 16,000 electric and hybrid electric vehicles operating in or around PGE's service territory, which is almost two-thirds of all electric vehicles in the state.[2] The number of public chargers in PGE territory in 2019 was estimated to be just under 1,000.[3] The Company estimates the load for electric vehicle charging in 2020 was 10 average MW (MWa) or 0.5 percent of 2020 retail sales.[4] They forecast this load will quadruple to 39 MWa by 2025 and then grow to 108 MWa, or approximately 5 percent of estimated retail sales, by 2030 or as EV adoption accelerates. Staff estimates that all PGE expenditures in TE currently total around $5.6 million. Finally, PGE forecasts that by 2025 TE infrastructure investments in its service territory will exceed $100 million annually.[5]

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[1] See 2020 Environmental, Social and Governance (ESG) report.
[2] See PGE 2019 Transportation Electrification Plan, Table 19, pg. 48.
[3] See PGE 2019 Transportation Electrification Plan, Table 11, pg. 33.
[4] See PGE 2019 Transportation Electrification Plan, Table 26, pg. 76. For retail sales, see the Oregon Public Utility Stat Book, pg. 15.
[5] See Staff/2002, PGE Response to Staff DR 487.

For FLDP, PGE is very active in developing a Flexible Load Plan, developing and conducting outreach around a comprehensive Distribution System Plan, hosting three Smart Grid Test Beds, and implementing several DR programs. Most notably, PGE's plan has specific, tangible DR goals. To this end, PGE staff are driving programs, investments, pilots, outreach, and new tariffs to meet these goals. Per PGE's latest IRP update, the goals are 141 MW of DR in the winter season and 211 MW of DR in the summer season.[6] PGE currently has 22 percent of all residential customers enrolled in some form of DR program.[7]

Q. What is PGE seeking to recover in this rate case?

A. PGE is seeking to recover the following expenditures in this rate case:

Program	**Staffing Expenditures** (FERC # 560, 580 908, 920)	**All Other Rate Case Expenditures**	**Total Rate Case Expenditures**
Transportation Electrification	$ 3,605,003	(-$ 278,700)	$ 3,326,303
DSP & FLP	$ 2,733,765	$ 411,223	$ 3,144,988
Demand Response and Smart Grid Test Bed	$ 2,759,888	$18,892,106	$21,651,995
Total	**$ 9,098,656**	**$19,303,329**	**$28,123,286**

Q. Will Staff be seeking more clarifications around these rate case expenditures in TE and FLDP?

6 *See* PGE LC 73, IRP update, January 29, 2021, pg. 11.
7 *See* DRRC Q3 meeting presentation.

A. Yes. Staff plans to follow-up on the following issues through discovery and future rounds of testimony:

- What activity is the reduction of (-$278,700) Transportation Electrification budget adjustment, under FERC Account 553, related to?
- What activity is the reduction (-$382,596) Demand Response budget adjustment, under FERC Account 451, related to?

Q. Do these rate case expenditures cover the full spectrum of TE and FLDP program activities?

A. No. Both TE and FLDP have several active deferrals dockets. These deferrals cover the costs of various pilots and programs. Staff estimates that TE pilots and programs have approximately $2.6 million in annual deferrals and the FLDP has $19 million in annual deferrals.[8] Staff will seek to confirm this in the next round of testimony.

Staff's estimate of the full amount of expenditures for TE and FLDP are as follows:

Program	2022 Rate Case	Est. Deferral for Pilots and Programs	Est. Total Cost
TE	$ 3,326,303	$ 2,600,000	$5.9 Million
FLDP	$ 24,796,983	$19,945,745	$44.7 Million

Q. How much have the expenditures in TE and FLDP increased since 2019?

[8] See Staff/1700, Shierman/4 for the TE deferral costs. See PGE UM 2141 Flexible Load Plan, May 18, 2021, Presentation for Public Meeting, pg. 7, for the FLDP

A. The programs and activities associated with these topics in the rate case are slated to grow over 2020 levels of expenditures. This does not include the expenditures associated with any deferrals.

Program	2020 Expenditures	2022 Rate Case Expenditures	Percentage Increase
TE	$ 741,453	$3,326,303	449%
FLDP	$10,062,065	$24,796,983	246%

The bulk of the growth comes from a nearly $9.0 million increase in incentives for DR and an approximately $3.0 million increase in incentives for the Smart Grid test bed.

Staff found that there have been notable areas of growth in staffing and incentive expenditures. The table below attempts to capture the relative rates of growth across staffing and incentives for TE and FLDP in rates:

Program	2020 Total	2022 Proposed	% increase
TE, Staffing (908 & 920)	$710,406	$3,605,003	486%
FLP & DSP, Staffing (560, 580, & 908)	$2,839,801	$2,733,765	(-4)%
DR, Staffing (908)	$420,860	$2,371,618	464%
Smart Grid Test Bed, Incentives (908 & 920)	$302,886	$388,270	28%
DR, Incentives (182)	$3,043,291	$12,083,208	297%
Smart Grid Test Bed, Incentives (182)	$371,988	$3,464,559	831%

ISSUE 2. ASSESSMENT OF TE AND FLDP EXPENDITURES

Q. How did Staff assess the growth in expenditures?

A. Staff recognizes that PGE is attempting to ramp customer demand for both TE services and the programs of FLDP. While the year-over-year jump in expenditures appears large on a proportional basis, the expenditures can be seen as analogous to starting-up a new business unit. To this end, our analysis focused on the reasonableness of the expenditures beyond just current customer demand. Staff assessed these TE and FLDP expenditures through the following questions:

- Are the expenditures tracked in a transparent manner?
- Are the expenditures appropriate relative to ratepayer benefits in 2022 and into the future?
- Are the expenditures reasonable relative to PGE's business goals?
- To what extent are TE and FLDP activities in necessary to contribute toward the energy goals of the state?

Q. What did Staff determine regarding TE activities?

A. As noted previously, PGE has forecasted a high level of growth in TE expenditures in this rate case. In fact, it would appear the $3.6 million in TE expenditures in the rate case are solely for staffing and management. This exceeds the total cost of all pilots and programs currently in deferrals.[9] In terms of transparency of expenditures, neither the 2019 TE Plan nor this rate

[9] See Staff/1700, Shierman 4.

case provide a clear insight into the rationale behind the high level of expenditures associated with TE staffing. For a complete understanding of TE activities, Staff and stakeholders must combine data from across multiple dockets and this rate case to create a snapshot of the portfolio of expenditures going forward into 2022. To this end, the transparency around some programmatic expenditures in the past have fallen short of statutory requirements. This issue is being addressed in Docket UM 2165 and is also covered in more detail in Mr. Shierman's testimony.[10]

Mr. Shierman addresses expenditures relative to ratepayer benefits in his testimony. In short, the quantifiable benefits to ratepayers do not outweigh the level of Company expenditures in the near-term. Staff understands the mitigating circumstances, which include that expenditures to develop a new markets, like TE, can exceed estimated near-term benefits, and that TE is central to the overarching state policy goals of decarbonization.

The balance Staff seeks to strike when engaging in TE policy development and implementation is to discern what investment decisions meaningfully contribute toward state policy goals in a cost prudent basis. Determining this will take on-going and regular engagement with the utilities, Commissioners, and stakeholders. Staff launched UM 2165 to develop a new framework for TE investments that better reflects the Governor's policy direction from EO 20-04 and from the recently passed legislation, HB 3055 and HB 2165. However, striking this balance will require PGE working with Staff

[10] See Staff/1700 Shierman.

and stakeholders to clearly articulate more specific, measurable, and time-bound goals for its TE activities. PGE's currently articulated goals from a data response appear somewhat ambiguous:

> In support of Oregon Senate Bill 1044, PGE's TE goals are set to accelerate electric vehicle (EV) adoption, leverage EVs for grid services and renewables integration, and efficiently integrate EVs and chargers into the grid. We believe meeting these targets will require significant capital investment to enable these goals over the next several years. While the company does not yet have Board-approved targets for 2022 and beyond we expect capital investment in TE–related activities to exceed $100 million per year beginning in 2025.[11]

By comparison, the planning and programmatic activities under the FLDP are linked to quantifiable goals of megawatt hours reduced while also tracking metrics such as levels of customer participation. Staff believes that this approach provides adequate transparency and accountability that allows Staff to track expenditures and ratepayer benefits, and Staff would like this approach to be replicated by the Company as its TE expenditures grow.

Q. What does Staff recommend for TE in this rate case?

A. In response to Staff Data Response 483, PGE notes that it has four full-time staff slated to be hired for its TE programs.[12] I support Ms. Cohen's adjustment that the costs of these four staff not be in included rates in this docket given how high TE staffing expenditures are relative to pilot and program activity. . Additionally, Staff recommends that increases in costs included in rates be contingent on PGE meets the following recommended actions. First, Staff

[11] See Staff/2002, PGE Response to Staff DR 487.
[12] See Staff/2003, PGE Response to Staff DR 483.

recommends that PGE launch a quarterly stakeholder engagement process to provide more regular and broader stakeholder feedback on all TE activities. This should reflect final Staff guidance presented in UM 2165 to address engagement of underserved communities and synchronization with TE Plan development. It may mirror approaches such as its DR review committee would mirror what is currently taking place.

Second, Staff recommends that PGE work with stakeholders as part of the UM 2165 and associated rulemaking process to develop quantifiable metrics for TE progress that are linked to medium-term goals (e.g., five years). Quantifiable targets or metrics to accelerate EV adoption and justify PGE's future staffing expenditures could range from MWH sales, rates and equitable location of charger installations (EV opportunities), GHG reductions from EVs in PGE territory, estimated displacement of gasoline and diesel sales, annual expenditures for line extension allowances, and/or the percent of EV load actively participating in DR programs.

Finally, prior to recovering TE positions in rates, Staff recommends that PGE launch a discussion around the adoption of performance based incentives for TE activities. Venues for this engagement could include future PGE stakeholder engagement meetings, the UM 2165 investigation, or even a section of the 2022 TE plan.

Q. Are you recommending that the Commission order PGE to leave the TE positions unfilled?

A. No. As explained in further detail in Ms. Cohen's testimony, Staff recommends that the costs of these positions be excluded from rates. However, Staff will be looking at whether PGE complied with the recommendations outlined herein in any future ratemaking proceeding in which PGE seeks to recover the costs of any new TE employees.

Furthermore, I recommend no specific adjustment to eliminate the costs of the four employees for this rate case. Staff witness Ms. Cohen has proposed an adjustment related to FTEs that subsumes my recommendation for cost recovery for the four employees at issue in my testimony.

Q. What did Staff find regarding FLDP expenditures?

A. Staff finds that the FLDP expenditures are broadly in keeping with the articulated activities and goals found across various documents. Staff does note that PGE will be shifting labor costs from flexible load pilot deferrals into base rates.

Q. Do you support PGE's plan to shift $0.8 million in labor costs for flexible load pilots from existing deferrals into base rates?

A. Yes. Staff agrees with PGE's statement that "labor is more flexible and can be applied to a variety of demand response programs".[13] PGE has instituted a product lifecycle management framework for vetting product ideas and developing them into PGE's flexible load product portfolio, as described in the Company's Flexible Load Plan.

[13] PGE/500, Bekkedahl – McFarland/10.

The framework involves engaging PGE staff from different departments as consultants to the pilot in areas such as customer experience, equity, product development, and grid operations. Staff has observed significant improvement in PGE's pilot design and evaluation resulting from this flexible use of staffing resources. PGE's proposal to include all flexible load labor costs in base rates is aligned with the Company's dynamic use of staffing as consultants under the product lifecycle management framework.

Q. Do you agree that non-labor costs for flexible load pilots should continue to be deferred?

A. Yes. The Commission has authorized deferred accounting and recovery of prudently incurred costs to deliver flexible load pilot programs and demonstrations because they involve uncertainty and risk and are mandated by the Commission.

Q. What is your opinion of the cost recovery alternatives to deferral proposed in Mr. Salmi Klotz's testimony?[14]

A. Staff is supportive of the concept in so far as it aligns with policy direction from the Commission's work under SB 978. However, we do not offer an opinion on the cost recovery alternatives at this time, as they do not directly relate to this rate case. PGE states that "[n]on-labor pilot costs … will continue to be deferred and amortized through supplemental schedules until Commission action on the Multi-Year Plan."[15] Staff will evaluate an alternative cost recovery

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[14] PGE/600, Salmi Klotz/8-11.
[15] PGE/600, Salmi Klotz/6.

mechanism at the time it is formally proposed by PGE as part of the Flexible Load Multi-Year Plan filing.

Q. What is your opinion of the regulatory alignment mechanisms described in Mr. Salmi Klotz's testimony that would allow PGE earnings on flexible load resource investments?[16]

A. Again, we do not offer an opinion on regulatory alignment mechanisms at this time, as they do not relate to this rate case. Mr. Salmi Klotz stated the Company's "intention to propose an adjustment mechanism either via the Multi-Year Plan process or the Distribution System Plan process, where appropriate stakeholder engagement can occur."[17] Staff will evaluate an earnings mechanism at the time it is formally proposed by PGE.

Q. Does your recommendation regarding cost recovery for unfilled positions extend to the FLDP?

A. Yes. Staff notes in testimony below the four activities that comprise the FLDP appear well staffed already. Again, this recommendation is subsumed into Ms. Cohen's recommendations regarding staffing levels for the whole company.

Q. Does Staff have any other observations on TE or FLDP expenditures?

A. Staff would note that PGE's forecasted staffing expenditures for TE and FLDP in this rate case are approximately $6.9 Million or roughly 21 percent of the combined total costs of all TE and FLDP activities. PGE planned in this rate case to employ nearly 16 FTE on TE and nearly 30 FTE on FLDP.

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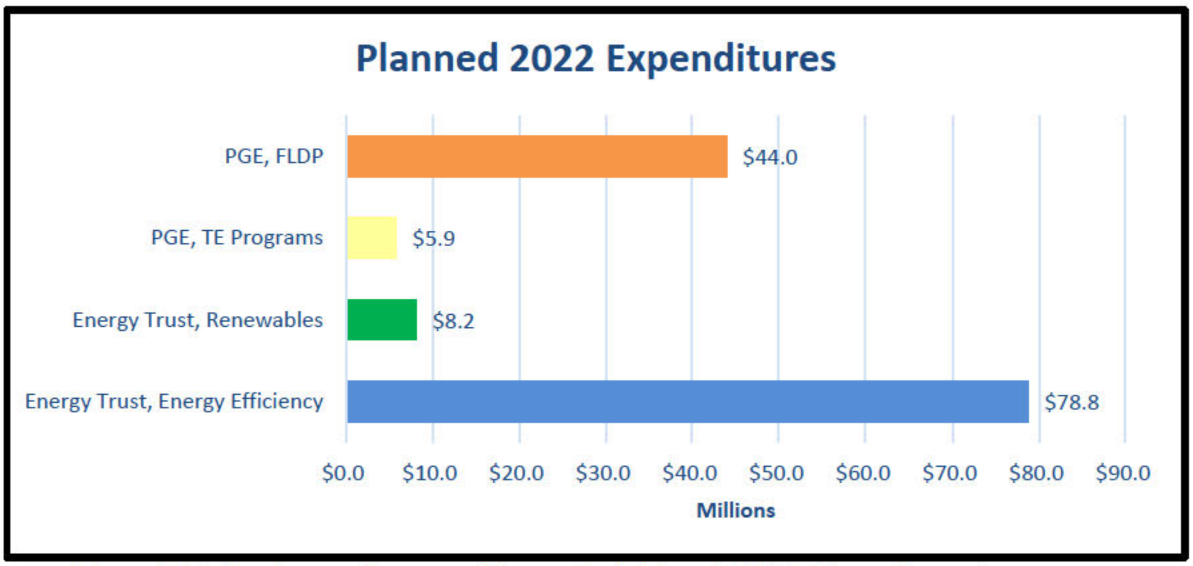
[16] PGE/600, Salmi Klotz/12-15.
[17] PGE/600, Salmi Klotz/16.

By comparison, Energy Trust's forecasts 2022 total staffing expenditures of approximately $17.5 Million or 8.6 percent of the entire 2022 budget.[18] Energy Trust forecasts it will have approximately 116 FTE employees in 2022. On an FTE per million expenditure basis, PGE's staffing expenditures are higher than Energy Trust.

Staff raises this point for two reasons. First, minding staffing costs relative to total programmatic expenditures and program goals contributes toward affordable rates. Additionally, if PGE were to miss TE or FLDP goals over several years, the efficacy of the Company's approach to staffing levels relative to program expenditures and results would need to be assessed.

Finally it is worth noting that PGE's planned 2022 expenditures in TE and FLDP relative to expenditures for Energy Trust of Oregon. The chart below



combines PGE's planned expenditures for TE and FLDP from the rate case and deferrals.

18 *See* Energy Trust of Oregon 2021 Annual Budget and 2021-2022 Action Plan, December 11, 2020, pg. 35.

The combined, estimated total 2022 expenditures associated with TE and FLDP *exceed* Energy Trust's annual renewable budget and amount to approximately 64 percent of the Energy Trust *total* budget. Staff notes this only to put in perspective the relative levels of oversight and public interaction staff seeks going forward on these broadly related customer-centric, public-policy driven activities.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 394
WITNESS: JEAN-PIERRE BATMALE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2001

Witness Qualifications Statement

October 25, 2021

WITNESS QUALIFICATION STATEMENT

NAME:	Jean-Pierre (JP) Batmale
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Division Administrator, Energy – Energy Resources & Planning Division
ADDRESS:	201 High Street SE, Suite 100 Salem, OR 97301
EDUCATION:	In 1993, I received a Bachelor of Arts Degree in Liberal Studies and History from the University of California, Riverside. In 1999, I received a Masters of Public Policy from University of California, Los Angeles.
EXPERIENCE:	From April of 2016 to the present, I have been employed by the OPUC. My current responsibilities include oversight of the Energy Resources & Planning Division. I have been the principal on following dockets: LC 66, LC 72, LC 73, UM 1565, UM 1696, UM 1845, UM 1892, UM 1893, multiple advice filings and reports. I have also contributed as staff and manager to many dockets, including UE 394.
OTHER:	From 2011 to 2016 I worked as a manager at Energy Trust of Oregon in their Production Efficiency Program and in their Planning & Evaluations Sector. Prior to that I worked at the Oregon Department of Energy as staff overseeing the Schools Program.

CASE: UE 394
WITNESS: JEAN-PIERRE BATMALE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 2002

Exhibits in Support Of Opening Testimony

October 25, 2021

September 10, 2021

To: JP Batmale
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 487
Dated August 9, 2021

Request:

For the following Key Policy Areas, please provide a description of the Company's business goals, including any financial targets (e.g., increases in kWh sold; increase in annual revenue; eligible capital deployed; etc.) and associated dates of those targets.

a. Transportation Electrification;
b. Distribution System Planning and Flexible Load Planning;
c. Integrated Resource Planning;
d. Demand Response and Smart Grid Test Bed;
e. Resource Adequacy Planning;
f. Resource Acquisitions/Request for Proposals (Origination…?);
g. VRET;
h. Portfolio Options;
i. Community Solar;
j. Community-Wide Green Tariff;
k. Promotional Concessions; and
l. PGE Marketplace

Response:

PGE has established company-wide goals for sustainability.[1] These goals are used to inform individual department goals on decarbonization, electrification and resource planning (i.e., Integrated Resource Planning and Distribution System Planning). Today, most department goals related to the key policy areas identified by OPUC Staff are established to implement policy and/or regulatory goals such as Oregon's 2017 Senate Bill 978. Additional information on our company goals can be found in PGE's response to AWEC Data Request No. 017 regarding

[1] More information on PGE's sustainability goals can be found at https://portlandgeneral.com/2019-sustainability-report.

PGE's "Vision and Strategy". The key policy areas listed above are centered around meeting customer needs and major state policy and regulatory goals. As such, these activities are often funded through O&M expenses and may be funded through capital investments, if needed.

The following are specific policies and rulemakings which have informed department specific goals:

a. Transportation Electrification (TE)
    - In support of Oregon Senate Bill 1044, PGE's TE goals are set to accelerate electric vehicle (EV) adoption, leverage EVs for grid services and renewables integration, and efficiently integrate EVs and chargers into the grid. We believe meeting these targets will require significant capital investment to enable these goals over the next several years. While the company does not yet have Board-approved targets for 2022 and beyond we expect capital investment in TE–related activities to exceed $100 million per year beginning in 2025.
b. Distribution System Planning (DSP) and Flexible Load Planning (FLP)
    - DSP: Core activities of the DSP team include, but are not limited to, forecasting distributed energy resource (DER) market size and customer adoption, establishing valuation methodologies to reflect market and regulatory developments, and leading the integration of DERs into the IRP and traditional DSP process. PGE's DSP goals are informed by Commission Order 20-485 (UM 2005).2 PGE has allocated existing positions and resources to meet the requirements of this order. PGE will evaluate UM 2005 requirements going forward to evaluate the need for additional resources. The first distribution system plan, part 1, will be submitted on October 15, 2021.
    - FLP: The goal of the FLP multiyear plan is to provide transparent portfolio-level planning and cost analysis, and to address the full value of PGE's flexible load resources to make a resilient and integrated grid. The multiyear plan will have a proposed two-year budget, a cost recovery proposal, outline of demand response (DR) activities over the next two years and cost effectiveness assessment of our FLP.
c. Integrated Resource Planning
    - The purpose of the IRP is to comply with Oregon Administrative Rule 860-027-0400 and to provide the Commission and stakeholders with a multi-year plan to meet customers' energy needs in a reliable manner that minimizes cost and risk while also meeting Oregon's greenhouse gas goals and PGE's commitment to cut PGE's greenhouse gas emissions by 80% by 2050. The IRP process also allows flexibility for adjustments as technology and policies continue to evolve.
d. Demand Response and Smart Grid Test Bed

[2] OPUC's Order 20-485 can be found at https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.

- PGE's DR program goals were established in PGE's 2019 IRP in Docket No. LC 73[3]. The goal of the program is to achieve DR savings of 211 MW in summer and 141 MW in the winter by 2025.
- Smart Grid Test Bed supports this goal through testing and evaluation of 1) new technologies and equipment to deliver demand response; 2) customer recruitment and retention strategies; and 3) approaches to optimize DR pilot and program performance. DR supports this goal through management and delivery of flexible load products, pilots, and programs.

e. Resource Adequacy Planning

- Advance PGE's alignment strategy in the Northwest Power Pool's regional resource adequacy effort to ensure equitable application of resource adequacy program requirements to participating entities in support of and in harmony with OPUC Docket No. UM 2143 (Investigation into Resource Adequacy in the State). PGE is seeking to ensure coordination between the state and regional resource adequacy efforts and aims to influence the regional program design proposal by year-end 2021 to achieve consistency with PGE priorities for resource adequacy and reliability.
- PGE is engaged in OPUC Docket No. UM 2024 (AWEC's Investigation into Long-Term Direct Access) to ensure that the protections built into the direct access regulatory framework require participating customers to pay their fair share of costs for programs and system resources that benefit them. In OPUC Docket No. UM 2143 PGE has articulated the position that all load-serving entities regulated by the OPUC (including direct access electricity service suppliers) meet minimum reliability standards by planning sufficiently in advance of need. PGE's intent is to leverage and build upon regional resource adequacy efforts through the design and implementation of a state-level framework that addresses the unique elements of the electricity industry in Oregon.

f. Resource Acquisitions/Request for Proposals

- Advances PGE's strategic plans for energy supply requirements to align with customer objectives. We lead/facilitate cross-functional efforts in acquiring/divesting of electric generation resources, including analysis, commercial negotiations, and obtaining regulatory approval with a clear focus on reliability and affordability for customers. Additional efforts support the optimization of PGE's Power Supply portfolio on behalf of customers, market design of customer product offerings, and certain aspects of business development in the region. These activities support the Commission Competitive Bidding Rules, among other regulatory requirements.

g. VRET/C&I Green Tariff

- The goal of this program is to provide large customers with renewable offerings that bring incremental renewable resources to PGE's grid. The program includes both a PGE supplied option and a customer supplied option. Phase I is fully

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[3] OPUC Docket No. LC 73, Order No. 20-152, https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

subscribed; phase II is preparing a subscription launch. This program is pursuant to Commission orders in Docket No. UM 1953, and Commission approved Schedule 55.

h. Community-Wide Clean Energy Program

   - The goal of the program is to support local government climate action goals and serve communities with 100% emissions free energy in advance of PGE corporate goals and new state mandates. This program will bring incremental renewable resources to PGE's grid that are supported by residential and small business customers within participating communities. It includes a local option for communities seeking to maximize community benefits associated with their investment in emissions free energy.

i. Portfolio Options

   - Program is not in base rates.

j. Community Solar

   - Support PGE's customers to ensure they receive the benefits of the Community Solar Program, while working to mitigate the impacts of cross-subsidization on non-participating customers, particularly low-income customers.

k. Promotional Concessions

   - As defined by Oregon Administrative Rule 860-026-0015, PGE's promotional concessions are aligned to our business goals around decarbonize, electrify, and perform imperatives as we work to help deliver a clean energy future. Promotional concession offers are designed to be customer-centric to help customers achieve their personal energy goals.

l. PGE Marketplace

   - The goal of the PGE Marketplace is to remove barriers to DR programs and accelerate DR acquisition by providing an opportunity to purchase thermostats and other products with an instant rebate through the Energy Trust of Oregon. The Marketplace allows customers to purchase a qualifying product, enroll in a DR program and receive rebates in a single transaction.

CASE: UE 394
WITNESS: JEAN-PIERRE BATMALE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2003

Exhibits in Support
Of Opening Testimony

October 25, 2021

September 10, 2021

To: JP Batmale
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 483
Dated August 9, 2021

Request:

Please provide an organization chart with names, titles, percentage FTE (e.g., 0.75 FTE) and FERC account number for all groups accountable for the design, implementation, operations, and/or oversight of the following key policy areas as reflected in the test year:

a. Transportation Electrification;
b. Distribution System Planning and Flexible Load Planning;
c. Integrated Resource Planning;
d. Demand Response and Smart Grid Test Bed;
e. Resource Adequacy Planning;
f. PURPA;
g. Resource Acquisitions/Request for Proposals (Origination…?);
h. VRET;
i. Portfolio Options;
j. Community Solar;
k. Community-Wide Green Tariff;
l. Promotional Concessions; and
m. PGE Marketplace.

Response:

Attachment 483-A provides the positions and FTEs represented by the key policy areas listed above as of August 2021. Highlighted cells represent vacant positions.

As mentioned in PGE's opening testimony in this general rate case, in order to effectively manage programs, labor resources need to be flexible. As a result, PGE does not assign FTEs to specific functions. Attachment 483-A is an example of how individual positions are involved in multiple efforts. Please note that percentages identified here may not be the same a year from now as our efforts shift when bills pass in the legislature or new dockets are opened.

Confidential attachment 483-B provides position descriptions for roles that dedicate at least 25% of their time to the key policy areas listed above.

Attachment 483-B contains protected information and is subject to General Protective Order No. 21-206.

CASE: UE 394
WITNESS: NICK SAYEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2100

Opening Testimony

October 25, 2021

Q. Please state your name, occupation, and business address.

A. My name is Nicholas (Nick) W. Sayen. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe Staff's preliminary analysis of the PGE Online Marketplace platform (Marketplace).

Q. How is your testimony organized?

A. My testimony is organized around the following topics:

<u>**OVERALL GOAL OF THE MARKETPLACE**</u>

Q. Please describe the Marketplace.

A. The Marketplace is a PGE-branded ecommerce website where residential PGE customers can purchase energy-related products such as smart thermostats, LED lightbulbs, and water fixtures.

Q. Please summarize the Company's proposal.

A. PGE is seeking cost recovery of $197,800 for capital associated with implementation of the Marketplace.[1]

Q. What is the overall goal of the Marketplace?

A. In PGE's response to Staff Data Request 481, the Company states the benefit of the Marketplace to cost-of-service customers is to remove barriers to participation in demand response programs. The Company states that the Marketplace allows residential customers to purchase qualified products (for example, a smart thermostat), enroll in a PGE demand response program, receive the program participation incentive, and receive an Energy Trust of Oregon rebate, in one single transaction.

Staff finds that the Marketplace is a reasonable approach to addressing barriers to participation in demand response programs. Approximately **[BEGIN CONFIDENTIAL]** [[redacted]] **[END CONFIDENTIAL]** smart thermostats have been sold on the Marketplace through August 2021.[2] Approximately **[BEGIN CONFIDENTIAL]** [[redacted]] **[END CONFIDENTIAL]** of those smart thermostats

1 Staff/2102, PGE response to Staff DR 481.
2 Staff/2103, Confidential PGE response to Staff DR 775 Attachment A.

have enrolled in PGE demand response programs.[3] Staff will continue to monitor enrollment data as one indicator of the success of the Marketplace in addressing participation barriers.

Staff also submitted discovery to ask how this enrollment rate compares to enrollment rates of products purchased through other channels. However, PGE objected to this request on the basis that it requires significant new work to compile this information. Subject to and without waving its objection, PGE responded: "Sell-through data for like products in alternate high volume retail channels, such as Amazon.com, is proprietary thus that analysis cannot be conducted."[4] The Company also noted in response that, since the launch of the Marketplace, about 25% of thermostats enrolled in PGE demand response programs were purchased on the Marketplace.[5]

3 Staff/2103, Confidential PGE response to Staff DR 775 Attachment A.
4 Staff/2102, PGE response to Staff DR 777.
5 Staff/2102, PGE response to Staff DR 777.

COSTS AND REVENUE

Q. Please describe the costs associated with the Marketplace.

A. The Company is seeking to recovery $197,000 in capital Marketplace costs in this case. If approved, these costs would be borne by cost-of-service customers. This cost is paid by PGE to the Marketplace implementer, Uplight, for startup activities.[6]

The Company is also deferring customer rebate fees of approximately $78,300 in a different docket. In dialogue with Staff on September 9, 2021, PGE explained these rebates are charged to the Company's Demand Response Deferral, UM 1708.[7] Costs for UM 1708 have been authorized for deferred accounting.[8] Subject to the processes and requirements of UM 1708, these costs are also ultimately borne by cost-of-service customers.

O&M costs are not included in this rate case, and so are borne by shareholders at this time. In dialogue with Staff on September 9, 2021, PGE stated that once these costs are more well-known and predictable, they may propose including them in rates in the future. O&M costs for the Marketplace include a $45,000 annual fee to the platform provider, and a $18,600 annual fee to an integration vendor for customer auto-enrollment in PGE demand response programs.[9] Total Marketplace costs can be seen in the table below.

Q. Please describe the revenue associated with the Marketplace.

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6 Staff/2102, PGE response to Staff DR 482 Attachment A.
7 Staff/2102, PGE response to Staff DR 481.
8 Order No. 21-291.
9 Staff/2102, PGE response to Staff DR 482 Attachment A.

A. From November 2020, when the program started, to July 2021, the Marketplace generated nearly $950,000 in total revenue from all device sales.[10] PGE receives two percent of this revenue, or nearly $19,000.[11] The vast majority of the total revenue – just over $880,000 – was generated from thermostat purchases.[12] Two percent of that revenue, or approximately $17,600, goes towards offsetting, or reducing deferral costs for UM 1708, thus benefitting cost-of-service customers.[13]

PGE's two percent of revenue generated from sales of other items goes towards offsetting the O&M annual fees.[14] The remaining revenue – nearly $69,000 – was generated from non-thermostat purchases,[15] and so two percent, or approximately $1,300, goes towards offsetting the O&M annual fees, and thus benefits shareholders.[16] Marketplace revenues can be seen in the table below.

Marketplace Costs, November 2020 to July 2021		
Borne by cost-of-service customers	Startup capital	$197,800
	Customer rebates for demand response participation through UM 1708	$78,300
Borne by the shareholders	O&M costs	$63,600

Marketplace Revenues, November 2020 to July 2021		
Recognized by cost-of-service customers	Revenue generated from t-stat sales, used to offset costs for UM 1708	$17,600
Recognized by the shareholders	Revenue generated from non t-stat sales	$1,300

10 Staff/2102, PGE response to Staff DR 482 Attachment A.
11 Staff/2102, PGE response to Staff DR 482 Attachment A.
12 Staff/2102, PGE response to Staff DR 482 Attachment A.
13 Staff/2102, PGE response to Staff DR 610.
14 Staff/2102, PGE response to Staff DR 610.
15 Staff/2102, PGE response to Staff DR 482 Attachment A.
16 Staff/2102, PGE response to Staff DR 610.

Q. Are there benefits to PGE associated with the Marketplace?

A. At this time the Marketplace O&M costs and revenue generated from non-thermostat sales are expected to result in a net expense to shareholders.[17] However, to the extent that the Marketplace is successful in reducing barriers to customer participation in demand response programs, the Company will benefit from increased program enrollment and improved program performance and achievement. The Company also likely enjoys indirect benefits, which may include improved customer satisfaction, improved and expanded PGE brand awareness, and positive media coverage.

[17] Staff/2102, PGE response to Staff DR 610.

CODE OF CONDUCT CONCERNS

Q. Please describe the Code of Conduct concerns with the Marketplace.

A. Staff does not currently have concerns regarding the Marketplace violating the Code of Conduct administrative rules. Prior to this rate case Staff raised concerns regarding the Marketplace and possible Code of Conduct issues. Staff investigated this issue and concluded that, because the Code of Conduct only applies to programs or offerings that are in the retail electricity market, it does not currently apply to the Marketplace because it is only offered to residential customers.[18] However, PGE stated that it intends to explore additional product offerings hosted on its Marketplace in the future, and so Staff will continue to monitor Code of Conduct concerns going forward.

[18] Staff/2102, PGE response to Staff DR 480 Corrected.

RISK

Q. Please describe Staff's analysis of risk.

A. Staff asked PGE to discuss any risks associated with the Marketplace, whether the risks are borne by cost-of-service customers, shareholders, or both, and to discuss any risk mitigation measures put in place to address these risks. PGE identified two risks: first, that end user data may be compromised, and second, that product availability may be disrupted due to pandemic related supply-chain problems.[19]

With respect to end user data, PGE noted that this risk to customers is mitigated because the Marketplace vendor ensures data is encrypted in transit and at rest and access to PGE Customer data is controlled, monitored, logged, and re-assessed.[20] However, PGE stated that if end user data is compromised, that risk is borne by the participating customer.[21]

Staff submitted discovery asking for a description of any PGE cost-of-service customer protections or liabilities, in terms of a financial or legal impact, should a data breach occur through the Marketplace. The Company responded that should a data breach occur, PGE and its vendor will assess whether that breach constituted a "Breach of Security" as defined in ORS 646A.600 and whether notice to the Oregon Attorney General and to consumers is required pursuant to ORS 646A.604.[22]

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19 Staff/2102, PGE response to Staff DR 480 Corrected.
20 Staff/2102, PGE response to Staff DR 480 Corrected.
21 Staff/2102, PGE response to Staff DR 480 Corrected.
22 Staff/2102, PGE response to Staff DR 648.

Depending on the Breach of Security, PGE and its vendor may offer credit monitoring services or identity theft prevention and mitigation services without charge to the customer.[23] Staff will submit further discovery to confirm the expenses for credit monitoring services or identity theft prevention and mitigation services would be borne by cost-service-customers or borne by shareholders. Other potential costs might include lost revenue due to system downtime, reputational damage, as well as any potential regulatory fines.[24] However, the financial impact of such a breach is difficult to calculate as the Marketplace has had a limited number of transactions and is receiving a limited amount of personally-identifiable information.[25]

PGE also responded that the Company conducted a security risk analysis prior to engaging with its vendor. The contract between PGE and the vendor contains confidentiality provisions and security standards and addresses the vendor's obligations around reporting and responding to security breaches.[26]

Q. Will Staff review testimony from other parties on these issues?

A. Yes, Staff will review and evaluate testimony from other parties and offer reply testimony on these in future rounds.

Q. Does this conclude your testimony?

A. Yes.

[23] Staff/2102, PGE response to Staff DR 648.
[24] Staff/2102, PGE response to Staff DR 648.
[25] Staff/2102, PGE response to Staff DR 648.
[26] Staff/2102, PGE response to Staff DR 648.

CASE: UE 394
WITNESS: NICK SAYEN

PUBLIC UTILITY COMMISSION
OF
OREGON

There is No
STAFF EXHIBIT 2101

Exhibits in Support
Of Opening Testimony

October 25, 2021

CASE: UE 394
WITNESS: NICK SAYEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2102

Exhibits in Support
Of Opening Testimony

October 25, 2021

August 31, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 481
Dated August 17, 2021

<u>Request:</u>

Please provide in narrative form a discussion of the accounting treatment of the Marketplace including:

a. Whether the costs of the PGE Marketplace are borne by cost-of-service customers, shareholders, or both; and

b. Whether the benefits of the PGE Marketplace are recognized by cost-of-service customers, shareholders, or both.

<u>Response:</u>

a. The rebates associated with the sales of thermostats on the platform are being deferred through PGE's Demand Response Testbed Pilot (Docket No. UM 1976) and Two Demand Response Pilots (Docket No. 1708). There are no incremental O&M costs associated with the Marketplace included in base rates in this general rate case. As a result, any O&M costs associated with non-demand response products up to this point were borne by shareholders. PGE has, however, included $197,800 of capital associated with the implementation of the Marketplace platform in this general rate case.

b. The PGE Marketplace benefits cost-of-service customers by removing barriers to demand response programs. Marketplace is designed to allow customers to purchase a thermostat, or other qualified products, enroll in a PGE demand response (DR) program and get an instant rebate. Without this option, customers would have to purchase the device on the broad market, separately enroll in the PGE DR pilot, then apply for a rebate through the Energy Trust of Oregon, and wait a number of weeks for that rebate to be mailed to the customer. The marketplace removes those barriers and allows customers to purchase a qualifying product, move through a streamlined program enrollment and receive rebates in a single transaction.

September 29, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 777
Dated September 15, 2021

Request:

Please provide a a) narrative description and b) spreadsheet showing how the data from DR 776 above compares to the Company's best available data for like products purchased through alternate highest volume channels. Please cite the source(s) of the data used in this comparison.

Response:

PGE objects to this request on the basis that it requires significant new work. Subject to and without waving its objection, PGE responds as follows:

Sell-through data for like products in alternate high volume retail channels, such as Amazon.com, is proprietary thus that analysis cannot be conducted. PGE considers the first year of Marketplace to a baseline year and will compare future year product sales to the first 12 months of sales activity.

Since the launch of PGE Marketplace, about 25% of enrolled thermostats were purchased on the PGE Marketplace.

For further details see PGE's response to OPUC Data Request No. 775, attachment 775-A.

August 31, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 482
Dated August 17, 2021

Request:

Please provide accounting records for any costs and revenues by month associated with the PGE Marketplace for 2019, 2020, and 2021.

Response:

Attachment 482-A provides the requested information.

Staff Exhibit

“Attachment 482-A”

is

filed in electronic format

August 31, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 481
Dated August 17, 2021

Request:

Please provide in narrative form a discussion of the accounting treatment of the Marketplace including:

a. Whether the costs of the PGE Marketplace are borne by cost-of-service customers, shareholders, or both; and
b. Whether the benefits of the PGE Marketplace are recognized by cost-of-service customers, shareholders, or both.

Response:

a. The rebates associated with the sales of thermostats on the platform are being deferred through PGE's Demand Response Testbed Pilot (Docket No. UM 1976) and Two Demand Response Pilots (Docket No. 1708). There are no incremental O&M costs associated with the Marketplace included in base rates in this general rate case. As a result, any O&M costs associated with non-demand response products up to this point were borne by shareholders. PGE has, however, included $197,800 of capital associated with the implementation of the Marketplace platform in this general rate case.
b. The PGE Marketplace benefits cost-of-service customers by removing barriers to demand response programs. Marketplace is designed to allow customers to purchase a thermostat, or other qualified products, enroll in a PGE demand response (DR) program and get an instant rebate. Without this option, customers would have to purchase the device on the broad market, separately enroll in the PGE DR pilot, then apply for a rebate through the Energy Trust of Oregon, and wait a number of weeks for that rebate to be mailed to the customer. The marketplace removes those barriers and allows customers to purchase a qualifying product, move through a streamlined program enrollment and receive rebates in a single transaction.

ORDER NO. 21-291

ENTERED Sep 10 2021

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1708(6)

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for Reauthorization of Deferred Accounting Related to Two Residential Demand Response Pilots.	ORDER

DISPOSITION: STAFF'S RECOMMENDATION ADOPTED

At its public meeting on September 7, 2021, the Public Utility Commission of Oregon adopted Staff's recommendation in this matter. The Staff Report with the recommendation is attached as Appendix A.

BY THE COMMISSION:

Nolan Moser
Chief Administrative Law Judge

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Circuit Court for Marion County in compliance with ORS 183.484.

ITEM NO. CA13

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: September 7, 2021

REGULAR ____ **CONSENT** __X__ **EFFECTIVE DATE** ______**June 23, 2021**______

DATE: August 30, 2021

TO: Public Utility Commission

FROM: Mitchell Moore and Kacia Brockman

THROUGH: Bryan Conway, John Crider, and Matt Muldoon **SIGNED**

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. UM 1708(6))
Requests reauthorization for deferred accounting related to two Residential Demand Response Pilots.

STAFF RECOMMENDATION:

Staff recommends that the Commission approve Portland General Electric's (PGE or Company) application for reauthorization of deferred accounting for costs related to two Residential Demand Response Pilots (Pilots) for the twelve-month period beginning June 23, 2021, subject to the conditions as outlined in this report's conclusion.

DISCUSSION:

Issue

Whether the Commission should approve PGE's request for reauthorization of deferred accounting for costs related to two Residential Demand Response Pilots for the twelve-month period beginning June 23, 2021.

Applicable Law

PGE submitted its filing pursuant to ORS 757.259 and OAR 860-027-0300 and Commission Order No. 15-203. ORS 757.259 authorizes the Commission to allow utilities to defer expenses or revenues for later amortization into rates to appropriately match ratepayer costs and benefits or to minimize the need for rate changes.
OAR 860-027-0300 specifies several requirements related to deferred accounting applications as well requests to amortize the deferred amounts. The Commission

previously approved PGE's original request for deferral of the incremental costs associated with these two pilots in its Order No. 15-203, and it was most recently reauthorized in Order No. 20-480.

Analysis

Background
PGE implemented two residential demand response pilots that the Company believes will best inform development of future demand response (DR) programs to be utilized as dispatchable resources during system peak loads as well as ease the integration of renewable energy sources. PGE began operating the two pilots in the third quarter of 2015.

The goal of the pilots through 2021 is to help PGE achieve at least 77 megawatts of demand response in the winter months and 69 MW in the summer months, while working to reach demand response high case targets of 162 MW (summer) and 191 MW (winter).[1]

FLEX 2.0
The first pilot is the Pricing and Behavioral Response Pilot, known as FLEX. The first stage of this pilot, referred to as FLEX 1.0, began by testing 12 pricing design options, all aimed at reducing residential peak demand during summer and winter months. This stage concluded in 2018.

After an independent evaluation of the first stage, PGE proposed moving forward by developing FLEX 2.0 as an opt-in scalable demand response pilot with appropriate Time-of-Use (TOU) prices and Peak Time Rebate (PTR). In response to Staff concern about the TOU rate design discouraging participation by electric vehicle owner, PGE eliminated the TOU rate and moved forward with a PTR-only offering that pays a rebate to customers that reduce their electricity consumption during winter and summer peak demand events.

PGE received Commission approval in April 2019 to update Schedule 7 to include PTR-only FLEX 2.0 pricing in Advice No. 19-03. As of May 2021, over 103,000 residential customers had opted into the FLEX 2.0 PTR offering. At the July 2021 Demand Response Advisory Group (DRAG) meeting, PGE reported PTR load shift of 11.4 MW in summer and 11.9 MW in winter.

While the pilot performance continues to improve, the Company also reported several challenges faced by PTR over the last year. Wildfires in 2020 and the ice storm in

[1] Order No. 17-386, p. 9.

February 2021 forced early ends to enrollment campaigns and seasons during which PGE could call PTR events. The heat wave in June 2021 resulted in lower than expected load shift during events.

PGE described strategies to mitigate these setbacks that include a promotional blitz, updating the PTR baseline model to address extreme temperature, allowing events on weekends and Mondays, and improving event notification success by transitioning from a vendor to an in-house solution. This latter solution is expected to result in cost savings, which will improve cost-effectiveness. PTR cost-effectiveness based on the total resource cost test is currently 0.7. The second-year PTR evaluation is due late summer 2021.

In May 2021, PGE released new opt-in TOU pricing.[2] The new pricing includes a 4.7 peak-to-off-peak price ratio that provides strong price signals for customers to shift their usage away from the peak. PGE will launch a TOU webpage, allow online enrollment, and begin a targeted marketing campaign in summer 2021. The Company included $0.64M in the FLEX 2.0 pricing deferral amount for these TOU activities.

Direct Load Control Thermostats
The second residential DR pilot in this deferral filing is the Direct Load Control Thermostat (DLCT) pilot. This pilot tests enabling thermostat technology to achieve automated load control among residential customers. The pilot began in November 2015 as a "Bring Your Own Thermostat" (BYOT) that was initially limited to the Google Nest thermostat and later expanded to additional manufacturers. In 2018, PGE expanded the pilot from BYOT to include direct installation of thermostats for eligible residential customers.

At the July 2021 DRAG meeting, PGE reported that the DLCT pilot has over 30,000 participants and is delivering 28.4 MW of capacity in summer and 7.8 MW in winter. In November 2020, PGE launched the online PGE Marketplace, which allows customers to enroll in the DLCT pilot as a BYOT customer at the time they purchase a qualifying smart thermostat. The purchase price is reduced by the Energy Trust of Oregon thermostat incentive and the BYOT enrollment incentive.

The program faced several challenges in the last year, including suspension of direct thermostat installations due to COVID-19, the suspension of the Energy Trust thermostat incentive after July 2021, and extreme weather events during which PGE decided not to call events in order to reduce impact to customers. PGE reported developments to the DLCT pilot that include improving customer engagement and education, testing day-ahead notification, refining customer recruitment based on better

[2] See Docket No. ADV 1194, PGE Advice No. 20-34.

insight into a home's heating and cooling equipment, and implementing intelligent demand response control strategies to reduce event overrides. The DLCT pilot's cost-effectiveness based on the total resource cost test is currently 0.9. The next DLCT pilot evaluation is due in September 2021.

Proposed Accounting:
PGE proposes to continue recording the deferred costs as a regulatory asset in FERC account 182.3, with a credit to FERC Account 456, Other Revenue.

Estimated Deferrals in Authorization Period

Cost per Pilot

Pilot	2021 Estimate
FLEX Pricing – PTR and TOU	$3.94 million
DLCT	$2.68 million
Total	**$6.63 million**

Information Related to Future Amortization

- Earnings Review – ORS 757.259(5) exempts amounts collected through an automatic adjustment clause from being subject to an earnings test.
- Prudence Review – No less than 90 days prior to filing to adjust tariff rates, PGE will submit two combined reports on the pilots, which will provide third-party evaluations, cost summaries, estimated curtailments, and results of customer satisfaction surveys.
- Sharing – Staff anticipates that there will be no sharing between PGE and its customers for this deferral.
- Rate Spread/Design – Rate spread/rate design is determined according to the terms set out in Schedule 135.
- Three Percent Test (ORS 757.259(6)) – The three percent test measures the annual overall average effect on customer rates resulting from deferral amortizations. The three percent test limits the aggregated deferral amortizations during a 12-month period to no more than three percent of the utility's gross revenues for the preceding year.

PGE Docket No. UM 1708(6)
August 30, 2021
Page 5

Conclusion

While this application for deferred accounting sees increased estimated costs in 2021, the costs appear appropriate given the increased complexity of the pilots and the forecasted participant growth. Staff concludes the DR Pilots are important to the development of future demand response programs and that granting reauthorization of the deferral will minimize frequency of rate changes and appropriately match the costs borne, and benefits received, by PGE customers.

Staff concludes that the Company's application for reauthorization of deferred accounting for costs related to two Residential Demand Response Pilots is consistent with ORS 757.259 and should be approved, subject to the following conditions:

PGE must:

1. At least annually, and not less than 90 days prior to the filing to adjust schedule 135 tariff rates, submit program costs (including forecasted program costs) to Staff for review of prudence.
2. No less than 90 days prior to filing to adjust tariff rates, hold at least one workshop to present pilot costs, findings, and any design updates. This requirement may be met by presentation at a quarterly Demand Response Advisory Group (DRAG) meeting.
3. No less than 90 days prior to filing to adjust tariff rates, submit two combined reports on the pilots, which will provide third-party evaluations, cost summaries, estimated curtailments, and results of customer satisfaction surveys.

PROPOSED COMMISSION MOTION:

Approve PGE's application for reauthorization of deferred accounting for costs related to two Residential Demand Response Pilots for the twelve-month period beginning June 23, 2021, subject to Staff's Conditions as outlined in this report's conclusion.

PGE UM 1708(6)

September 15, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 610
Dated September 2, 2021

Request:

Referring to the tab labeled "Revenues" of Attachment 482-A, please provide a narrative of the accounting treatment of revenues, including:

a. Whether the revenues of the PGE Marketplace are recognized by cost-of-service customers, shareholders, or both.

Response:

Revenues that PGE receives from sale of thermostats that were enrolled in Demand Response programs will offset costs in deferred account number 1823002 and will be amortized to customers. The remainder of the revenues will be used to offset a portion of the O&M expense of the PGE Marketplace in account 9030001. PGE has not budgeted O&M expenses or their corresponding revenues for non-demand response associated sales from the Marketplace in this general rate case. As such, both the O&M expenses and revenues will be recognized by PGE shareholders at this time, which is expected to be a net expense.

September 2, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Corrected Response to OPUC Data Request 480
Dated August 17, 2021

Request:

Please provide in narrative form a general overview of the PGE Marketplace, found online at pgemarketplace.com, including a discussion of:

a. Any risks associated with the PGE Marketplace, and whether the risks are borne by cost-of-service customers, shareholders, or both.
b. Any risk mitigation measures put in place to address these risks.
c. Description of the relationship PGE has with the Marketplace administrator (identifying name and its ultimate parent company).
d. Relationships the administrator has with retailers, if any.
e. Any plans or possibilities for expanding the PGE Marketplace to additional customers, including any potential timelines for doing so.

Response:

Overview:

The PGE Marketplace Application is a PGE Branded eCommerce website where PGE Customers can securely purchase energy-related products. The Marketplace allows customers to browse, compare, and purchase energy products online, with the opportunity for point-of-sale or instant rebates and incentive redemptions to be applied during checkout.

a. There are two types of risk associated with Marketplace: end user data and product availability.
   - End user data: As with all ecommerce sites, the PGE Marketplace relies on end user data and information to process transactions. There is a risk that data could be compromised despite the measures used to safeguard it.
     - This risk is borne by the participating customer.
   - Product availability: The pandemic has disrupted supply chains, so products are not always available to customers when they shop on the Marketplace.
     - This risk is borne by the participating customer.

b. End user data risk mitigation: To protect PGE Customer data confidentiality the marketplace vendor, Simple Energy, ensures data is encrypted in transit and at rest. To protect data integrity, access to PGE Customer data is controlled, monitored, logged, and re-assessed. To protect PGE Customer data availability, it is replicated to several secure datastores across multiple regions.

   Product availability risk mitigation: PGE's marketplace team and Simple Energy's staff (see part c, below) correspond with original equipment manufacturers to identify product inventory counts and potential disruptions to fulfillment or manufacturing. When disruptions are identified, messaging is placed on Marketplace web pages informing customers of potential fulfillment delays or products being out of stock (so they cannot be purchased).

c. PGE works with Simple Energy as an authorized program implementer. Simple Energy is responsible for all the services provided through the PGE Marketplace.

d. Simple Energy does not have any direct relationships with retailers. Simple Energy works with industry leading energy and home related product manufacturers and distributors to provide these products on the Marketplace.

e. PGE marketplace is currently available to all *residential* PGE customers.

September 24, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 648
Dated September 10, 2021

Request:

Referring to PGE's response to DR 480a and 480b regarding end user data, please provide in narrative form:

a. A description of any PGE cost-of-service customer protections or liabilities, in terms of a financial or legal impact, should a data breach occur through the PGE Marketplace.

Response:

Financial impact
The financial impact of a Breach of Security (as defined in ORS 646A.600) is difficult to calculate as PGE Marketplace has had a limited number of transactions and is receiving a limited amount of personally identifiable information. Potential costs associated with a Breach of Security would include expenses associated with providing customers credit monitoring services or identity theft prevention and mitigation services, lost revenue due to system downtime, reputational damage, as well as any potential regulatory fines.

Legal Impact
Should a data breach occur, PGE and its vendor Simple Energy (an executing entity of Uplight, Inc.) will assess whether that breach constituted a "Breach of Security" as defined in ORS 646A.600 and whether notice to the Oregon Attorney General and to consumers is required pursuant to ORS 646A.604. Depending on the Breach of Security, PGE and Simple Energy may offer credit monitoring services or identity theft prevention and mitigation services without charge to the customer.

Additionally, PGE conducted a security risk analysis prior to engaging with Simple Energy. The contract between PGE and Simple Energy contains confidentiality provisions and security standards, and addresses Simply Energy's obligations around reporting and responding to security breaches.

CASE: UE 394
WITNESS: NICK SAYEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2103

Confidential Exhibit in Support
Of Opening Testimony

October 25, 2021

September 29, 2021

To: Nick Sayen
Public Utility Commission of Oregon

From: Jaki Ferchland
Manager, Revenue Requirement

Portland General Electric Company
UE 394
PGE Response to OPUC Data Request 775
Dated September 15, 2021

Request:

Please provide the following records by month, for the PGE Marketplace for 2019, 2020, and 2021:

a. Count of unit sales, by product type;
b. Count of units receiving Energy Trust rebates, by product type; and
c. Count of units receiving PGE demand response program participation incentives, by product type.

Response:

Confidential attachment 775-A provides the requested information.

Attachment 775-A contains protected information and is subject to General Protective Order No. 21-206.

Confidential Staff Exhibit

“Confidential Attachment 775-A”

is

filed in electronic format

CERTIFICATE OF SERVICE

UE 394

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 25th day of October, 2021 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (971) 375-5079

UE 394 SERVICE LIST

AWEC	
JESSE O GORSUCH **(C)** **(HC)** DAVISON VAN CLEVE	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com
CORRINE MILINOVICH **(C)** **(HC)** DAVISON VAN CLEVE, P.C.	1750 SW HARBOR WAY, STE. 450 PORTLAND OR 97201 com@dvclaw.com
TYLER C PEPPLE **(C)** **(HC)** DAVISON VAN CLEVE, PC	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com
CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C)** **(HC)** RICHARDSON ADAMS, PLLC	PO BOX 7218 BOISE ID 83702 greg@richardsonadams.com
GREG BASS CALPINE ENERGY SOLUTIONS, LLC	401 WEST A ST, STE 500 SAN DIEGO CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** **(HC)** ENERGY STRATEGIES LLC	215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com
FRED MEYER	
JUSTIN BIEBER **(C)** FRED MEYER/ENERGY STRATEGIES LLC	215 SOUTH STATE STREET, STE 200 SALT LAKE CITY UT 84111 jbieber@energystrat.com
KURT J BOEHM **(C)** BOEHM KURTZ & LOWRY	36 E SEVENTH ST - STE 1510 CINCINNATI OH 45202 kboehm@bkllawfirm.com
JODY KYLER COHN **(C)** BOEHM, KURTZ & LOWRY	36 E SEVENTH ST STE 1510 CINCINNATI OH 45202 jkylercohn@bkllawfirm.com
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
WILLIAM GEHRKE **(C)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97206 will@oregoncub.org

MICHAEL GOETZ **(C)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 mike@oregoncub.org
PGE	
PORTLAND GENERAL ELECTRIC	pge.opuc.filings@pgn.com
LORETTA I MABINTON **(C)** **(HC)** PORTLAND GENERAL ELECTRIC	121 SW SALMON ST - 1WTC1711 PORTLAND OR 97204 loretta.mabinton@pgn.com
JAY TINKER **(C)** PORTLAND GENERAL ELECTRIC	121 SW SALMON ST 1WTC-0306 PORTLAND OR 97204 pge.opuc.filings@pgn.com
STAFF	
STEPHANIE S ANDRUS **(C)** PUC STAFF--DEPARTMENT OF JUSTICE	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us
JILL D GOATCHER **(C)** PUC STAFF--DEPARTMENT OF JUSTICE	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 jill.d.goatcher@doj.state.or.us
MATTHEW MULDOON **(C)** PUBLIC UTILITY COMMISSION OF OREGON	PO BOX 1088 SALEM OR 97308-1088 matt.muldoon@puc.oregon.gov
WALMART	
VICKI M BALDWIN **(C)** PARSONS BEHLE & LATIMER	201 S MAIN ST STE 1800 SALT LAKE CITY UT 84111 vbaldwin@parsonsbehle.com
STEVE W CHRISS **(C)** WAL-MART STORES, INC.	2001 SE 10TH ST BENTONVILLE AR 72716-0550 stephen.chriss@wal-mart.com
MADELILNE MALMQUIST **(C)** WALMART	madelinemalmquist@parsonsbehle.com