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

December 2, 2021

Via Electronic Filing

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

Re: UE 394 – Portland General Electric Company's Request for a General Rate Revision

Dear Filing Center:

Included for filing in the above referenced docket, is Portland General Electric Company's Reply Testimony.

- PGE / 1300 through PGE / 2200

Work papers will be emailed to puc.workpapers@puc.oregon.gov.

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

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

Jaki Ferchland
Portland General Electric Company
Manager, Revenue Requirement
121 SW Salmon Street, 3WTC0306
Portland, OR 97204

Confidential material in support of this filing has been provided to parties under the General Protective Order No. 21-206 issued June 24, 2021, and Modified Protective Order 21-237 issued July 27, 2021.

Sincerely,

/s/ Jay Tinker

Jay Tinker
Director, Rates & Regulatory Affairs

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Maria Pope
Brett Sims

December 2, 2021

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I. Introduction and Overview

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

A. My name is Maria Pope, and I am President and Chief Executive Officer (CEO) of PGE. My name is Brett Sims, and I am PGE's Vice President of Strategy, Regulation and Energy Supply. Our qualifications were previously provided in PGE Exhibit 100.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is three-fold:

- To provide an overview of our updated general rate case and summarize the major themes of our reply testimony.
- To provide general context for PGE's reply testimony responding to concerns expressed by Public Utility Commission of Oregon (Commission or OPUC) Staff (Staff) in opening testimony regarding PGE's approach to cost controls and keeping rates as affordable as possible for customers while pursuing the Company's strategic vision to decarbonize, electrify and perform.
- To introduce other PGE testimonies that reply to this and other unresolved issues raised by Staff and other parties.

Q. Please provide an overview of this general rate case thus far.

A. In PGE's direct testimony, filed on July 9, 2021, we explained the essential investments made by PGE to continue providing safe, reliable, secure, and affordable service to our customers while also modernizing the grid and promoting decarbonization and electrification. These investments include strengthening the transmission and distribution system, improving customer service and customer engagement capabilities, and technological upgrades that will efficiently integrate renewable resources, distributed energy resources, flexible loads and other smart grid technologies. We also explained the steps PGE took to minimize the price increase requested in this case and reduce the impact on customers, especially in light of the continuing effects of the worldwide COVID-19 pandemic. On October 25, 2021, Staff and intervenors filed opening testimony in which they recommended various adjustments to PGE's filing. Since PGE's initial filing, the parties have resolved several significant issues in the case through settlement.

Q. Please describe the settlements PGE has entered related to this proceeding.

A. PGE has entered into three settlements that relate to this rate case, which are reflected in the updated revenue requirement set forth in Exhibit 1400.

First, PGE entered into a stipulation on August 31, 2021 to settle all issues related to net variable power costs (NVPC). Although NVPC was addressed in Docket No. UE 391 (UE 391), PGE is tracking all NVPC updates and stipulations in the UE 394 revenue requirement. As of the final November 15, 2021 update, this results in an $33.4 million increase to the revenue requirement initially filed in this docket.

Second, PGE and the parties to this proceeding entered into a stipulation (the first UE 394 Stipulation) on September 30, 2021 that settled all issues related to cost of capital, including cost of debt, return on equity, and PGE's capital structure. This settlement reduced PGE's revenue requirement by $7.4 million.

Third, on November 5, 2021, PGE and parties entered into a stipulation (the second UE 394 Stipulation) that resolved several revenue requirement issues. Among other items, the settling parties agreed upon the cost of the new Integrated Operations Center (IOC) included in this case, PGE agreed to remove the Beaver Modernization and Excitation System projects from the case due to delays in their in-service dates, and the parties agreed not to oppose approval of PGE's deferral associated with the February 2021 ice storm and to adjust the Level III Outage Accrual to remove costs associated with that storm. Overall, this settlement reduced PGE's revenue requirement by another $3.5 million. After accounting for the Oregon Corporate Activities Tax (OCAT), which stipulating parties agreed to move from a supplemental schedule to base rates (i.e., a revenue neutral adjustment), the reduction is $12.2 million.

Q. Please provide a comparison of the revenue change PGE proposed in its initial filing with the increase you now support.

A. PGE initially proposed a total revenue requirement increase of $99 million (including the increase for NVPC), which represented a 4.9 percent rate increase in base rates and a 3.9 percent rate increase overall, after accounting for supplemental tariffs.[1] PGE has updated its revenue requirement for the stipulations listed above plus four power cost updates filed on July 15, October 1, November 5, and November 15, 2021 along with the most recent load forecast. Based on these updates, PGE's request in this case is approximately $22.5 million higher than that listed in PGE's initial filing, driven by power costs and the inclusion of the OCAT in base rates. After adjusting for the geographical shift of OCAT, PGE's request in this case is approximately $13.8 million higher than its initial filing, driven entirely by an increase in power costs. Focusing only on non-NVPC items, however, the stipulations and updates in this docket have reduced PGE's proposed revenue requirement increase from $59.0 million to approximately $30.7 million. PGE's current revenue requirement is discussed in Exhibit 1400.

[1] PGE/100, Pope-Sims/16.

Q. What other reply testimony is PGE submitting?

A. The following PGE testimony responds to unresolved issues raised by Staff and other parties:

- **1400 – Revenue Requirement**

  Alex Tooman and Greg Batzler provide an updated revenue requirement, as mentioned above, and they respond to multiple adjustments proposed by Parties to topics such as other revenues, lease expense, payroll tax, and allowance for funds used during construction. They also address Parties' comments to PGE's Level III Outage Mechanism proposal and the flexible load plan.

- **1500 – Compensation**

  Anne Mersereau and Tamara Neitzke support PGE's total labor requirements in this rate case by highlighting PGE's modest request in the face of growing inflation. They also provide further support for PGE's incentives request, which was already reduced by 50% when PGE filed this rate case.

- **1600 – Corporate Support**

  Jim Ajello and Greg Batzler respond to Staff's adjustments to administrative and general non-labor expenses by addressing PGE's responses to OPUC Data Request Nos. 57 and 58 and confirming that no double counting of expenses is occurring. They also refute recommendations made by Parties related to insurance, margin interest, revolver fees, and information technology projects.

- **1700 – Customer Service**

  Larry Bekkedahl and John McFarland provide additional support for PGE's request to extend the use of the fee-free bank card program to non-residential customers and highlight the benefits to all customers of additional payment options. They also respond to adjustments made by Parties to PGE's transportation electrification spending by highlighting how PGE's efforts align with state goals to reduce greenhouse gas emissions and efforts made across the electric utility industry.

- **1800 – Capital Budgeting Controls and Process**

  Larry Bekkedahl and Archie Ewers provide a comprehensive explanation of PGE's capital budgeting process and the controls employed be PGE to ensure that investments made are the right investments to support PGE's long-term mission to provide safe, reliable, and affordable power to its customers.

- **1900 – Production**

  Larry Bekkedahl and Stefan Cristea address proposed adjustments related to Trojan Decommissioning and then focus on providing additional information on the Faraday Repowering Project.

- **2000 – Transmission and Distribution**

  Larry Bekkedahl and Bradley Jenkins respond to and offer recommendations to improve Staff's proposed wildfire mitigation performance mechanism. They then offer further support for the prudence of the ADMS investments and, finally, discuss adjustments and offer additional details for 22 capital projects highlighted by Staff in their opening testimony.

- **2100 – Load Forecasting**

  Amber Riter discusses PGE's September load forecast update, responds to recommendations made by Parties on energy efficiency and COVID-19 impacts, and discusses large customer load forecasts.

- **2200 – Pricing**

  Rob Macfarlane and Teresa Tang provide an update of the overall rate impacts to various rate schedules and address issues raised by other parties around rate spread and rate design. PGE agrees to make several changes suggested by parties and further explains its position on many issues including the non-bypassability of costs incurred as a result of public policy directives and allowing balances associated with decoupling to be carried forward while not impacting customer prices by more than 2% in any given year.

II. Context for this Case

Q. In your direct testimony, you explained that this case advances PGE's customer-driven strategic vision to decarbonize, electrify and perform,[2] which also aligns with state policy.[3] Have recent events confirmed the importance of PGE's decarbonization efforts?

A. Yes. In July 2021 the Oregon legislature passed House Bill (HB) 2021, and the new law took effect on September 25, 2021. HB 2021 establishes aggressive emissions reduction targets for PGE that ramp up to 100 percent below baseline emissions levels by 2040.[4] PGE must file a clean energy plan with the Commission that includes actions to meet PGE's clean energy targets and produce an affordable, reliable, carbon-free electric system. PGE's investments contained in this case will help PGE meet these new requirements by upgrading and strengthening the transmission and distribution system, implementing the Advanced Distribution Management System (ADMS) to enable integration of additional renewable and distributed energy resources, and providing customers with reliable clean energy from the Faraday hydroelectric facility for decades to come. In these and other ways, this rate case represents an important early step in PGE's implementation of the new law. The passage of HB 2021 further confirms that PGE's vision is aligned with state policy of decarbonizing the grid while maintaining reliability and affordability.

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[2] PGE/100, Pope-Sims/8-9.
[3] PGE/100, Pope-Sims/13-14.
[4] *See* Public Utility Commission of Oregon, HB 2021 Summary, *available at* https://www.oregon.gov/puc/Documents/HB2021-Summary.pdf.

Q. In your direct testimony, you acknowledged the ongoing customer impact from the COVID-19 pandemic while also anticipating that economic recovery would continue.[5] Have economic conditions continued to improve in the five months since you filed your direct testimony?

A. Yes. Oregon's economy continues to improve, with forecasted tax revenues increasing and unemployment decreasing.[6] While we remain focused on minimizing the customer price impacts of this rate case, the modest increase we have proposed is reasonable under these circumstances—particularly since it will not take effect until midway through 2022, after continued economic recovery is expected.

Q. PGE's direct testimony also explained that increasing inflationary pressure created challenges for PGE in controlling costs.[7] Does this remain true in the current economic environment?

A. Yes. In recent months, inflation has increased, with the annual inflation rate in the United States reaching 6.2 percent in October 2021, which is the largest 12-month increase since 1990.[8] As inflation has increased, PGE's cost-control efforts and the very modest price increases PGE proposes in this case appear even more reasonable. For instance, PGE proposes wage and salary escalations of just 2.5-3.5 percent,[9] and PGE continues to manage its operations & maintenance (O&M) costs to a level well below the average rate of inflation.

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[5] PGE/100, Pope-Sims/4.
[6] *See* https://www.oregonlive.com/business/2021/10/oregon-unemployment-rate-falls-to-47-near-historic-lows-but-job-growth-is-flat.html; https://www.opb.org/article/2021/11/17/oregon-revenue-tax-forecast-taxpayer-kicker/.
[7] PGE/400, Ajello-Batzler/3-4.
[8] U.S. Bureau of Labor Statistics, The Economics Daily, "Consumer prices increase 6.2 percent for the year ended October 2021," *available at* https://www.bls.gov/opub/ted/2021/consumer-prices-increase-6-2-percent-for-the-year-ended-october-2021.htm.
[9] PGE/300, Mersereau-Neitzke/18.

Q. Have the challenges posed by the COVID-19 pandemic and current economic conditions prevented PGE from executing its strategic investments for the benefit of customers?

A. No. The past two years brought pandemic-related labor and supply-chain challenges, and in recent months, inflation and supply-chain disruptions have increased. Despite these difficult conditions, PGE successfully completed many important components of its capital budget—including the IOC, which came in under budget—and strengthened the reliability of its transmission and distribution system. PGE's investments will deliver a more resilient system that is prepared for further decarbonization while maintaining affordability.

III. PGE Focus on Cost Control and Affordable Rates

Q. Staff criticizes PGE for focusing on innovation and environmental goals, rather than on keeping rates as affordable as possible.[10] Please summarize PGE's prior testimony regarding PGE's cost controls and measures taken to maintain affordable prices for customers.

A. We addressed cost controls and measures the Company took to minimize the impact of this rate case on customer prices in PGE's direct testimony, both in our direct Policy Testimony, Exhibit 100, and in extensive individual testimonies detailing PGE operations. The Company's delay of roughly a year in filing the rate case reflected our acute awareness of and sensitivity to the potential impact of a price increase on customers, especially during the pandemic, and we took specific actions to reduce costs, minimize the price impacts, and defer the effective date for the price change to a time of year when demand for power and customer bills are typically lower. As noted in our direct policy testimony and supported with detail in further direct testimony regarding our operations[11], those actions include:

- Managing our operations and maintenance (O&M) costs carefully to keep the increase in O&M to a level well below the average rate of inflation;
- Excluding officer incentive compensation and removing 50% of all other forecasted incentive compensation;
- Proposing no increase in return on equity (ROE);
- Maintaining the uncollectibles rate approved in PGE's last general rate case;

[10] Staff/100, Muldoon/5-6.
[11] UE 394 / PGE Exhibits 100, 200, 400, 700, and 800

- Reducing information technology (IT) costs through the use of cloud-based services that also provide more reliability, support business continuity plans, enhance customer service, and increase financial transparency;
- Renegotiating long-term service agreements to reduce costs and increase value;
- Improving plant management practices to reduce costs while maintaining reliability;
- Improving line operations processes to reduce reliance on contractors; and
- Reducing material costs through supplier renegotiations.

Q. Does PGE's focus on the environmental and transformational elements of its strategic vision overshadow its focus on controlling costs, as Staff claims?[12]

A. No. On the contrary, PGE's strategic vision to decarbonize, electrify and perform is firmly grounded in our awareness that cost and delivering value for customers matter. In particular, PGE's "perform" goal includes a strong emphasis on operational efficiency and increasing customer value while reducing costs. Our role as a vertically integrated utility is critical both from the standpoint of achieving decarbonization consistent with the state's climate and clean energy policies and from the standpoint of keeping the system safe, reliable, and affordable for customers. Each of these imperatives is equally important and all must be achieved.

Q. Does PGE's drive to innovate conflict with maintaining affordability and reliability?

A. No. Innovation supports and furthers affordability and reliability. Innovations included in this rate case—like the grid management technologies incorporated into the new IOC, upgrades and improvements throughout our distribution system, and innovative program development

[12] Staff/100, Muldoon/5-6.

in support of distributed energy resources and transportation electrification (TE)—are necessary to provide affordable and reliable service to customers.

Q. How do these innovations improve customer outcomes or experiences?

A. While innovations require investments with customer price impacts, they also deliver substantial benefits and are necessary to meet evolving customer expectations. Investments to support electric vehicle charging, for instance, help meet a customer need that is projected to expand exponentially in the near future – and must, to meet state greenhouse gas reduction goals. At the same time, however, increased electric load from TE will bring with it increased revenue, which is expected to result in overall downward price pressure that benefits all customers. Innovation in support of grid modernization is another area where customers enjoy benefits from more reliable service both in day-to-day operations and in the face of extreme weather events, while innovation in support of flexible load offerings gives customers more options for managing their energy use – and their costs – while giving the utility more tools to manage costs and reliability for the entire system.

Q. Could failing to innovate increase costs and risks to customers?

A. Yes. To echo the Commission's mission statement, PGE is seeking, through innovation driven by customer value, "To ensure Oregon utility customers have access to safe, reliable, and high-quality utility services at just and reasonable rates." Failing to innovate could result in potential added costs and risks to customers from reduced resiliency, flexibility, and lost opportunities to improve systems and processes over time. For instance, implementing the ADMS and the services to customers those systems will support is essential to reliable operation of the smart grid, the integration of distributed variable-output renewable generating resources, and effective power restoration during extreme weather events like those we've seen in the past 14 months (wildfire, ice, heat). Not making the investments necessary to manage the grid effectively and efficiently eventually leads to increased costs and service degradation.

Q. What examples did Staff provide to support their assertion that PGE lacks focus on controlling costs?

A. Staff highlighted four areas they believe show a lack of focus on cost control:

- PGE's third quarter, 2020 energy trading losses;
- The Company's accounting practices as reflected in transactional data submitted for the rate case;
- Cost control for capital investments in transmission and distribution facilities, including the new IOC; and
- Attention to costs relating to investment in repowering the Faraday hydro facility.[13]

We will discuss each in turn.

Q. Do PGE's energy trading losses in the third quarter of 2020 show a lack of focus on cost control?

A. No. PGE took quick and decisive action to eliminate its net market exposure from the energy trading positions that led to the losses in the third quarter of 2020, including immediate management changes to enhance oversight of trading operations. At the same time, an expert external consultant and a PGE Board of Directors Special Committee began a review of the Company's related procedures and controls and the trading activity that led to the losses. In addition, PGE quickly made the decision to insulate customers from bearing any costs from those trades and resulting trading losses. The actions the Company began taking while the

[13] Staff/100, Muldoon/7-8.

Special Committee's review was underway ultimately proved to be consistent with the opportunities the Committee identified to improve the Company's energy trading policies and practices, and the Board of Directors is monitoring progress through enhanced reporting.

Q. Please describe the actions taken to reduce the potential for these kinds of losses in the future.

A. These actions included:

- Bringing in additional experienced risk management personnel and replacing the Power Operations general manager and individuals responsible for the trades;
- Strengthening trading policies and procedures with revisions designed to prevent market positions of the type that led to the losses by placing controls on the ability of personnel to enter into wholesale energy transactions if PGE does not have physical or financial delivery capability;
- Enhancing risk reporting for energy trading activity to ensure greater visibility into portfolio risk; and
- Changing reporting structures so that Energy Trading Risk Management now reports through a Risk and Compliance team that reports to the Chief Financial Officer, and Power Operations now reports to the Vice President of Strategy, Regulation and Energy Supply.

In addition, the Board of Directors concluded that, considering the losses, it would be inconsistent with PGE's pay-for-performance philosophy for the CEO, the Chief Financial Officer, and one additional officer to receive any annual incentive compensation for 2020.

Q. Does Staff's testimony on risk protocols recognize the steps PGE has taken to strengthen its risk protocols?

A. Yes. PGE appreciates Staff witness Dr. Curtis Dlouhy's recognition that PGE's practices have improved and mitigated its market risk.[14] Dr. Dlouhy recommends additional measures he believes PGE should implement to strengthen its risk evaluation, which PGE will take into consideration as it reviews its energy trading protocols and procedures for further possible improvements.

Q. How do the actions PGE took in response to the 2020 trading losses reflect on the Company's commitment to controlling costs for customers?

A. The actions PGE took in response to the 2020 losses reinforce, rather than call into question, the fact that the Company is committed to keeping a strong focus on cost control to the benefit of customers, and PGE's response demonstrates that it will promptly take appropriate corrective measures when needed. For example, the Company quickly decided that all costs attributable to the losses, as well as the losses themselves, would not be recovered in this rate case or otherwise. The Company's response to this incident illustrates its commitment to transparency and accountability, which is key to efficiency and effectiveness and therefore cost control.

Q. As a second example of PGE's lack of focus on cost control, Staff testified that PGE's accounting practices were difficult to understand and contained insufficient detail.[15] Please respond.

A. Staff's testimony is perplexing because PGE's accounting protocols are fully consistent with industry and utility best practices and do not reflect any change in long-standing accounting and reporting methodologies. The final accounting data we provided in response to Standard

[14] *See* Staff/600, Dlouhy/51, 57.
[15] Staff/100, Muldoon/6-7.

Data Requests (SDRs) 057 and 058, which Staff cited in its testimony,[16] was consistent with the level of detail and categorization of data provided in response to the same SDRs in PGE's last five general rate cases prior to docket UE 394.[17] Staff has not previously raised these concerns.

As is explained in detail in PGE Exhibit 1600, PGE understands that some revised responses were necessary to provide additional clarity to Staff, and we welcome a discussion with Staff on how best to modify the data provided in response to these SDRs in future rate cases. However, Staff's assertion that the accounting information provided "still includes over $5 million of transactions with no explanation indicating what they were for" is incorrect based on the data PGE provided.[18] All but two of the line entries identified by Staff as problematic are for non-labor-related allocations that are documented and then allocated to a variety of accounts based on PGE's cost allocation criteria, which are provided to the Commission annually.[19] The entries include numerous informational fields describing the basis for expenditure. PGE Exhibit 1600 explains the cost allocation process in detail, including the prudence of costs detailed, and rebuts other Staff proposals that appear to be based on an incorrect understanding of PGE's accounting data or are otherwise unsupported.

Q. Staff's third example relates to an alleged lack of cost control for PGE's capital investments in transmission and distribution (T&D) facilities, including the new IOC.[20] Do PGE's T&D capital investments show a lack of focus on cost control?

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[16] Staff/100, Muldoon/6.
[17] This coincides with the number GRCs PGE has filed since SDRs were required pursuant to OAR 860-022-0019(2)(a): UE 262, UE 283, UE 294, UE 319, and UE 335.
[18] Staff/100, Muldoon/7.
[19] See the Cost Allocation Manual, provided as Attachment 2 to PGE's annual Affiliated Interest Report in accordance with OAR 860-027-0048(6).
[20] Staff/100, Muldoon/7.

A. No. PGE's Exhibits 1800 and 2000 address the Company's capital budgeting process and T&D capital projects – with testimony providing detailed information demonstrating the prudence of 22 specific projects questioned by Staff – offering thorough documentation that PGE has strong controls in place at every level and a clear focus on managing costs.

Q. Did PGE update its capital budgeting process in 2019 to improve project selection, resource utilization, and accountability to benefits and outcomes?

A. Yes. Capital projects now follow a standard stage-gating process to approve funding by stage, aligning monetary commitment with the level of confidence around project scope, schedule, and budget. The process is governed primarily by the PGE Board of Directors, the Company's Capital Review Group, and the Business Sponsor Group.

Q. Does PGE's management of the IOC project show a lack of focus on cost control?

A. No. On the contrary, the IOC was recently placed in service, and due to PGE's diligent application of cost controls, it came in approximately $9 million (about 4 percent) under budget. While PGE takes issue with Staff's overall assertion that they were "unable to detect a focus on cost control for PGE's capital investments in transmission and distribution facilities" and we provide detailed rebuttals, by project, in Exhibit 2000, Staff's decision to call out the IOC "for apparent mismanagement of costs" is especially mystifying.[21] The IOC was deemed to be a critical and high priority project for the Company based on size, complexity, risk and strategic importance. It received the highest level of oversight, including oversight from PGE's Board of Directors. Costs related to the facility have now been settled with Staff and other parties and are addressed as part of the second UE 394 Stipulation. While many of PGE's other capital projects are not on the scale of the IOC, the general approach we

[21] Staff/100, Muldoon/7.

took with this project reflects our comprehensive system for managing costs on projects large and small.

Q. Finally, Staff claims that PGE's investment in the Faraday hydro facility demonstrates a lack of attention to costs.[22] Please respond.

A. PGE has acted prudently on customers' behalf throughout the Faraday review and repowering project. The Company engaged a reputable firm to conduct a complex and detailed study to determine the repowering option most beneficial to customers and then structured the contract to complete the project appropriately. In PGE Exhibit 1900, Larry Bekkedahl and Stefan Cristea provide a detailed explanation of the analysis behind PGE's decision to proceed with repowering the facility, thus retaining an important contributor to resource diversity in our carbon-free generating mix, and the Company's administration of the contract governing the construction project. We acknowledge that this highly complex project to repower an important legacy hydro project – inherently a significant and challenging effort – has been delayed, in part because of unprecedented challenges during construction that could not have been predicted or avoided (COVID, wildfire at the construction site, flooding, and ice storms). While no one of these events should cause major delays on a project of this size, in combination they resulted in multiple demobilization and mobilization issues, losses of qualified workers to complete the project in a timely manner, and additional costs associated with these delays. Each time the project was shut down due to flooding, or evacuation of the worksite for the safety of workers due to wildfires, or unsafe working conditions due to ice and storm related power outages, it put a real strain on the contract crews. If those events were not enough, COVID-19 impacts also contributed with the loss of construction leadership

[22] Staff/100, Muldoon/7.

and qualified personnel on the job site throughout the past 18 months. We remain confident that upon completion, Faraday will continue to serve as a reliable, cost-effective, emissions-free capacity resource to the benefit of customers for decades to come.

Q. Please provide additional perspective on PGE's efforts to contain costs and maintain affordable prices for customers.

A. As we noted previously, PGE is acutely aware that some of its customers continue to experience negative impacts from the COVID-19 pandemic and we remain focused on minimizing costs while also investing to ensure safe, reliable, and clean electric service today and into the future. However, the primary drivers behind this rate case are long-lead capital additions that directly benefit customers and cannot be rescheduled for a more convenient time. As we have described above and address in detail in our reply testimony, PGE exercises strong cost controls in the selection and management of these projects. Furthermore, PGE has made a concerted effort to mitigate our rate increase request and customer price impact through continued efforts to reduce costs and improve efficiency across the organization and by implementing targeted and ongoing O&M cost reductions within Administrative & General (A&G) cost centers and other areas of the company. The timing of the filing of this case also reflects our sensitivity to customer price impacts, with the proposed price change effectiveness targeted for a time of year with lower electricity demand and customer bills.

Some of these efforts are described in detail in Exhibit 400 of PGE's direct testimony and resulted in an overall decrease to A&G costs from 2020 to 2022 of approximately $6.6 million at a time when we are experiencing a 30-year high in inflationary pressures. The most recent Oregon Office of Economic Analysis economic forecast indicates Oregon Average Wage Rate inflation of 5.0% in 2021 and 3.0% in 2022, U.S. Average Wage Rate inflation of 5.2% in

2021 and 3.6% in 2022, and its West Region Urban Consumer Price Index forecasts inflation of 4.5% in 2021 and 3.9% in 2022.

Q. Please provide examples.

A. PGE included in A&G targeted reductions of approximately $5.4 million in corporate costs (largely reflecting forecasted base budget wages and salaries), $1.8 million in corporate governance costs, and $1.5 million in supply chain costs. In addition to these A&G budget reductions, PGE included $23.0 million in identifiable budget reductions in 2022 test year O&M costs.

These reductions were partially offset by unavoidable A&G and O&M cost increases in areas such as business continuity and emergency management and benefits. Details on both the reductions and increases are provided in PGE Exhibits 400 and 1600.

III. Summary and Conclusions

Q. Please summarize your testimony.

A. PGE has navigated exceptionally challenging conditions to successfully complete numerous capital projects that will benefit customers today and into the future. To recover the cost of these projects, PGE has proposed a modest rate increase that is necessary and reasonable in the current rising cost environment. PGE has also worked diligently to implement cost control measures and to ensure that it provides customers with efficient and high-value service at reasonable rates. We strongly disagree with Staff's assertions that the Company lacks focus on cost control and has mismanaged or failed to properly account for costs, and that our focus on decarbonization and innovation overshadows our commitment to cost control. PGE rebuts those assertions with detailed documentation in our reply testimony. We believe the record reflects our focus and effectiveness at actively managing costs and our attentiveness to customer prices and affordability.

Q. What do you request of the Commission?

A. We request that the Commission approve the settled issues, as they represent reasonable resolutions of those issues. With the support of the documentation we provided in direct testimony, in response to data requests, and with this reply testimony, PGE requests that the Commission approve PGE's revised request for a $103.5 million increase to revenue requirement, inclusive of NVPC and load forecast updates, remembering that as noted in Section I of this testimony, focusing only on non-NVPC items, the settlements and updates in this docket have reduced PGE's proposed revenue requirement increase from $59.0 million to approximately $30.7 million.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Alex Tooman, Ph.D.
Greg Batzler

December 2, 2021

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I. Introduction

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

A. My name is Alex Tooman. I am a Senior Regulatory Consultant for PGE.

My name is Greg Batzler. I am a Regulatory Consultant for PGE.

Our qualifications were previously provided in PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address certain issues and proposed adjustments raised by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), the Oregon Citizens' Utility Board (CUB), and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to PGE's 2022 test year revenue requirement.

Q. What specific issues do you address in your testimony and how is it organized?

A. We address the following issues:

- Section II - Accumulated Deferred Income Taxes;
- Section III - Allowance for Funds Used During Construction;
- Section IV - Other Revenue;
- Section V - World Trade Center Lease;
- Section VI - Colstrip;
- Section VII - Payroll Taxes;
- Section VIII - Allocation of Smart Grid Costs;
- Section IX - Level III Outage Restoration Mechanism;
- Section X - Flexible Load Plan; and
- Section XI - Other Issues.

Q. Does PGE plan to file supplemental reply testimony addressing Parties' issues and proposed adjustments relating to deferred accounting?

A. Yes. In accordance with Commission Order No. 21-436, PGE plans to file supplemental reply testimony on these issues on December 8, 2021.

Q. Has PGE entered into any settlements in this proceeding?

A. Yes. PGE entered into a stipulation on August 31, 2021 to settle all issues related to net variable power costs (NVPC). Although NVPC has been addressed in Docket UE 391 (UE 391), we are recording all NVPC updates and stipulations in the UE 394 revenue requirement. PGE also entered into a stipulation (First Stipulation) on September 30, 2021 to settle all issues related to cost of capital, including cost of debt, return on equity, and PGE's capital structure. Most recently, PGE entered into a partial stipulation (Second Stipulation) resolving adjustments to the Integrated Operations Center (IOC) and other discreet revenue requirement items.

Q. Has PGE updated the revenue requirement in Docket UE 394?

A. Yes. PGE has updated its revenue requirement for the stipulations listed above plus four power cost updates as filed on July 15, October 1, November 5, and November 15, 2021, along with the most recent load forecast. Based on these updates, PGE's request in this case is approximately $22.5 million higher than that listed in PGE's initial filing, with an overall rate increase now at 5.11%. However, approximately $8.7 million of this revenue increase relates to the Oregon Corporate Activity Tax (OCAT), which is shifting from a deferral to base rates. After adjusting for this revenue neutral impact, the $22.5 million becomes $13.8 or a 4.69% increase. Focusing only on non-NVPC items, however, the settlements and updates in this docket have reduced the proposed revenue requirement increase from

$59.0 million to approximately $30.7 million (also excluding the impact from OCAT). We provide a summary of the current revenue requirement as PGE Exhibit 1401.

II. Accumulated Deferred Income Taxes

Q. Please describe AWEC's proposed adjustments related to Accumulated Deferred Income Taxes (ADIT).

A. AWEC raises four distinct issues regarding PGE's ADIT balance included in rate base. First AWEC recommends removing 50% of PGE's incentive-related ADIT balance.[1] Second, AWEC disagrees with PGE's inclusion of ADIT associated with PGE's Level III reserve account. Third, AWEC argues that two ADIT items associated with Boardman should be removed from rate base.[2] Specifically, AWEC argues for removal of approximately $8.8 million associated with Boardman Cost of Removal and approximately $2.4 million associated with Boardman Inventory Write-Off because, according to AWEC, "(n)early all decommissioning activities are complete."[3] Finally, AWEC recommends adjusting PGE's ADIT associated with the Production Tax Credit (PTC) carryforward balance based on a revised calculation of that carryforward.

Q. Did PGE resolve any of these adjustments in the Second Stipulation?

A. Yes. The parties settled the first issue (removal of incentive ADIT) and the third issue (Boardman ADIT). As a result, we will not address those issues in our testimony here.

A. Level III Reserve ADIT

Q. Please summarize AWEC's proposed adjustment regarding the Level III Reserve ADIT.

A. AWEC employs convoluted logic to contest inclusion of ADIT for the Level III storm reserve, suggesting that the timing difference between PGE's collections for the Level III reserve

[1] AWEC/100, Mullins/27-28.
[2] AWEC/100, Mullins/29.
[3] AWEC/200/page 29/lines 20-21.

versus the costs applied against the reserve, is not really a timing difference for regulatory purposes.[4]

Q. How do you respond to AWEC's adjustment?

A. We disagree. ADIT and deferred tax expenses exist because of differences in amounts recorded for book accounting and tax accounting purposes (book/tax differences). Although AWEC singularly attributes timing as the basis of the Level III Reserve ADIT, timing is typical of many book/tax differences that give rise to ADIT. In short, timing does not make the Level III Reserve ADIT unusual for either accounting or regulatory purposes.

Q. Is the Level III Reserve ADIT unusual in any other aspects?

A. Yes. Because the current Level III Reserve mechanism is asymmetrical (as discussed in PGE Exhibit 800 and in Section IX, below), the reserve cannot have negative balances, which means that any Level III Reserve ADIT can only be an asset. This asymmetry also means that PGE can incur significant amounts of unrecoverable costs as occurred with the 2014-2017 Level III events. If, however, the Commission were to approve PGE's proposal to revise the mechanism and make it symmetrical, then book/tax differences would still exist, but the associated ADIT could have both asset and liability balances. Presumably, AWEC would not object to ADIT liability balances in rate base. In summary, the Level III Reserve ADIT is not only a function of book/tax differences but is also directly related to the structure of the regulatory mechanism, and hence, it should be appropriately reflected for regulatory purposes.

B. PTC Carryforward ADIT

Q. Please summarize AWEC's proposed adjustment regarding the PTC carryforward ADIT.

[4] AWEC/100, Mullins/28-29.

A. AWEC recommends "using the actual PTC utilization from the year ending December 31, 2020, adjusted for the 2020 trading losses, as a proxy for the PTC utilization that will occur in 2021."[5] AWEC also recommends "rolling forward the PTC carryforward balance for an additional five months to reflect the timing of the rate effective date in this proceeding."[6] AWEC's calculation produces a $51,656,844 reduction to PGE's rate base.[7]

Q. Do you agree with AWEC's analysis and adjustment?

A. No, with one exception. We do not disagree with the concept of rolling forward the PTC carryforward balance but note that PGE's rate base was set as of April 30, 2022, so the balance should be rolled forward only an additional four months rather than five. Otherwise, we disagree with AWEC's adjustment.

Q. Please explain the problems in AWEC's adjustment.

A. AWEC applies incorrect assumptions to calculate PGE's 2021 PTC carryover amount in rate base. Before doing so, however, AWEC states that "there is no reliable way to determine the level of PTCs that will be utilized on PGE's 2021 tax return in order to develop an estimate of the PTC carryforward balance as of December 31, 2021."[8] AWEC solves this issue by assuming that:

- "Given the declining PTC carryforward balances, it is certainly possible that the PTC carryforward balance will decline substantially by December 31, 2021 and even further reductions may be expected by the rate effective date of May 1, 2022";[9] and

[5] AWEC/100, Mullins/32.
[6] AWEC/100, Mullins/32.
[7] AWEC/100, Mullins/32.
[8] AWEC/100, Mullins/31
[9] AWEC/100, Mullins/31

- 2021 PTC utilization will be at least equal to 2020 utilization absent the impact of PGE's trading losses.

The first assumption lacks a sound basis and is merely speculation. The second assumption is not reasonable because it considers no detail from either 2020 or 2021 with which to accept 2020 as a "proxy for the PTC utilization that will occur in 2021."[10]

Q. Please elaborate.

A. Absent the trading losses, 2020 resulted in higher-than-projected usage of PTCs. In contrast, based on year-to-date information, 2021 will result in lower-than-projected usage of PTCs based in part on: 1) the February ice storm, which represents deferred cost for book accounting and regulatory purposes but expense for tax purposes; 2) impacts associated with the summer heat waves; and 3) the additional plant PGE has added. In summary, 2020 does not represent a reasonable proxy for 2021 PTC utilization and attempting to equate the two years represents an oversimplification. AWEC compounds this oversimplification by further projecting the 2020 results into the first five months of 2022—rather than four months—and through a significant mathematical error in AWEC's PTC calculation, resulting in an artificially low value for the April 30, 2022 PTC carryforward.

Q. What mathematical error is embedded in AWEC's adjustment?

A. In their work paper, AWEC incorrectly labels the 2022 PTC carryover as the 2021 carryover, but more importantly, AWEC failed to include the 2021 carryforward as part of the net total carryforward. Correcting this error alone adds approximately $27.4 million to the ending balance.

Q. Did you make any other corrections to AWEC's adjustment?

[10] AWEC/100, Mullins/32

A. Yes. We adjusted the 2020 PTC utilization to reflect actual PTC usage based on PGE's 2020 tax return, filed in September 2021.

Q. How do you propose to address the recommendation to roll forward the PTC carryforward balance for an additional four months?

A. PGE agrees that the PTC carryover balance should be updated to correspond to PGE's rate base effective date of April 30, 2022 (not May 31, 2022 as calculated by AWEC). To do so, we update AWEC's work paper to include the January through April portion of: 1) the current 2022 forecast of PTCs to be generated; and 2) utilization based on PGE's 2022 filed net income (as provided in PGE Exhibit 201). In short, we use forecasted 2022 amounts consistent with those provided in this rate case, but we reject AWEC's 2020 amounts as erroneous, ongoing proxies for future years.

Q. What is your proposal for the PTC carryforward balance in rate base?

A. Adjusting for all the items we discuss above, AWEC's corrected work paper provides a PTC carryover of approximately $68.0 million, which is approximately $1.8 million lower than PGE's filed PTC carryover forecast.

III. Allowance for Funds Used During Construction

Q. Please describe AWEC's adjustment for Allowance for Funds Used During Construction (AFUDC).

A. AWEC bases their adjustment on PGE's response to AWEC Data Request (DR) No. 100, where PGE states that the depreciation expense PGE included in revenue requirement does not include a reversal of AFUDC equity. As such, AWEC concludes that because "the reversals are not included in the regulatory accounting,"[11] PGE does not need to include the permanent book tax difference within its calculation of taxable income.

Q. Is AFUDC equity included in PGE's book depreciation?

A. Yes. PGE's book depreciation includes AFUDC equity. It appears that AWEC misunderstood PGE's response to AWEC DR No. 100, where PGE used the word "reversal" to mean the removal of AFUDC equity. In fact, PGE's depreciation expense, as included in PGE Exhibit 203 and PGE Exhibit 200 work paper "Exhibit Support 2022" includes AFUDC equity. PGE clarified this point in PGE's response to AWEC DR No. 190, which states, "(d)epreciation expense is calculated on total book basis, including AFUDC."[12]

Q. Is it appropriate to include the flow through book tax difference associated with AFUDC equity?

A. Yes. Because PGE's book depreciation expense is calculated in total on the entire plant in-service including AFUDC, it is appropriate to reverse AFUDC equity, which is (along with other components) tracked in PGE's tax record, from taxable income.

[11] AWEC/200/page 27/line 8.
[12] Provided as PGE Exhibit 140X.

IV. Other Revenue

Q. What issues have Parties raised regarding Other Revenue?

A. The Parties' specific proposals regarding Other Revenue are as follows:

- CUB proposes a $165,121 increase to Other Revenue to account for expected increases in outdoor activity and PGE campground fees in 2022.[13]
- AWEC proposes a $1.0 million increase to Other Revenue based on PGE filing a transmission rate case with the Federal Energy Regulatory Commission (FERC). AWEC also indicates that "Since the impacts of that case will be known by the time that this case is resolved, I recommend including the incremental revenues from PGE's OATT rate case filing in this case."[14]
- Staff proposes to increase Other Revenue by $8.8 million based on: 1) primarily three mathematical analyses of PGE's 2016-2021 actual Other Revenue activity; and 2) the recent contract between PGE and the Northern Wasco Public Utility District (PUD).[15]

Q. How do you respond to CUB's proposal?

A. Although the recovery of campground activity in 2022 from the COVID emergency and lockdowns entails considerable uncertainty, PGE accepted CUB's proposal for settlement purposes in the Second Stipulation.

Q. Do you accept AWEC's proposal?

A. No. PGE Exhibit 200 explained how PGE would meet the requirements of Commission Order No. 19-400 to "propose a method to hold all customer classes harmless, preventing double

[13] CUB/200, Gehrke/5-7.
[14] AWEC/100, Mullins/44
[15] Staff/1300, Zarate/9-15.

recovery, for the time between the rate effective date in FERC and Commission rate cases including the reclassified assets, in the event such a timing mismatch occurs."[16] PGE proposed its method explicitly because (contrary to AWEC's assertion) the impacts of the FERC case will not be known by the time this general rate case (GRC) is resolved.[17] In addition, AWEC was a party to the UM 2031 stipulation that stated "Staff, CUB, and AWEC agree to support PGE's efforts to develop and obtain Commission approval in this pursuit to hold customers harmless."[18]

Q. Do you agree with Staff's analysis and proposed adjustments?

A. In part. We accept Staff's adjustment regarding PGE's contract with the Northern Wasco PUD. We disagree with Staff's adjustment related to its three analyses of PGE's 2016-2021 actual Other Revenue activity.

Q. Why do you disagree with Staff's three analyses?

A. Staff's analyses are fundamentally flawed because they do not consider what the numbers mean or how they need to be treated in analyses. Each of Staff's analyses produce very similar results because: 1) certain components of PGE's Other Revenue impact each of Staff's analyses in the same way; and 2) those are the components that need to be evaluated further.

Q. Which components of Other Revenue need to be evaluated further?

A. The three variables are Forfeited Discounts (i.e., late payment charges – PGE account 4500001), Other Electric Revenues (PGE account 4560001), and Regulatory Deferral Revenue (PGE account 4560002). In each case, their recent activity is not representative of test year activity and need to be normalized for Staff's type of analyses.

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[16] Commission Order No. 19-400, page 5; PGE/200, Tooman-Batzler/11.
[17] PGE/200, Tooman-Batzler/10-11.
[18] Commission Order No. 19-400, page 6.

Q. Please provide more detail regarding the Forfeited Discounts.

A. In general, Forfeited Discounts do not fluctuate significantly from year to year but 2018-2021 have reflected considerable variation for two very different reasons. First, in 2018 and 2019, actuals were much higher than usual due to the implementation of PGE's Customer Care and Billing system in 2018. This resulted in PGE limiting credit and collection activities including: 1) not disconnecting customers during a portion of the system go-live and stabilization period; and 2) suspending late notices and/or credit reminder calls, in part to minimize calls to the Contact Center. This suspension of activities resulted in a higher level of payment arrearages in 2018 and 2019, and consequently, higher amounts of late payment fees.

In 2020 and 2021, in response to the COVID-19 emergency, PGE suspended late payment fees in accordance with Commission Order No. 20-401. While Staff acknowledged this aspect in their second analysis, they incorrectly normalized it by taking the average of the prior three years of actual activity. In other words, Staff used the inordinately high levels of 2018 and 2019 actuals to adjust the inordinately low 2020 and 2021 amounts in their second analysis. This was an improper adjustment approach because 2018 and 2019 represent very non-normal levels of Forfeited Discounts and should not be used to adjust the non-normal amounts from 2020 and 2021.

Q. Please provide more detail regarding the Other Electric Revenues.

A. Other Electric Revenues reflect miscellaneous revenues not included in other accounts recording Other Revenue. Examples include park and recreation revenues, customer technical services, and facilities charges. This account also does not typically fluctuate significantly from year to year. However, as noted in PGE's response to Staff DR No. 557 (provided as

Staff Exhibit 1302) and as discussed in Exhibit 200, page 9, PGE account 4560001 reflects revenue "*that offsets expenses* PGE incurred during the same period to provide project support for a third-party accessing PGE equipment" (emphasis added).[19] We specifically addressed this in PGE Exhibit 200: "Because of the temporary and uncertain nature of these *costs and revenues*, neither have been forecasted for 2022" (emphasis added).[20]

Q. Please provide more detail regarding Regulatory Deferral Revenue.

A. For test year forecasts, Account 4560002 includes costs associated with PGE's major maintenance accruals (MMAs) and should not be included in any analyses such as those performed by Staff.

Q. Please provide a brief summary of PGE's MMAs.

A. PGE's MMAs are approved mechanisms for normalizing the periodic and lumpy costs associated with the major maintenance of PGE's thermal plants and discussed in PGE Exhibit 700, Section III, Part B. Based on proper accounting, PGE is required to separate the costs associated with MMAs into two components: Generation operations and maintenance (O&M) and Other Revenue. In total, the two components sum to the amount that PGE needs to recover for MMAs in the test year forecast as listed in Table 1, below.

Table 1
MMA Accounting Summary ($000)

Accounting Category	**MMA Cost by Category**
MMA Cost in Account 4560002	$4,764
MMA Cost in Generation O&M Accounts	$11,560
Total 2022 MMA Forecast	**$16,324**

Q. Please explain why Other Revenue would be associated with accounting for MMAs.

A. MMAs in any given GRC are calculated to address the following two aspects:

[19] PGE/200, Tooman-Batzler/9.
[20] PGE/200, Tooman-Batzler/9.

- The forecast of average costs for the next three to five years (depending on the thermal plant) to normalize the costs for rate setting; and
- A true up of under- or over-collected MMA-related costs since the last GRC.

The true up of under- or over-collected MMA-related costs is why PGE accounting reflects some of the MMA costs in Other Revenue. This amount, however, is still part of the overall MMA amount to be recovered in rates.

Q. Please summarize your testimony regarding the MMA costs in Other Revenue.

A. MMA costs relate exclusively to Generation O&M. Consequently, they should be: 1) addressed only as part of Generation O&M; and 2) completely factored out of any analysis regarding Other Revenue.

Q. How would you represent Other Revenue if all the normalization adjustments are applied as you discussed above?

A. Exhibit 1402 provides a comparison of 2016 through 2022 Other Revenue. The "Unadjusted" tab provides unadjusted 2016-2021 actual Other Revenue compared to the 2022 test year forecast. The "Adjusted" tab includes the following normalization adjustments to provide a more meaningful comparison to the 2022 test year forecast:

- Remove detail for account 4500001, Forfeited Discounts, from the listing because the 2018-2021 actuals are <u>all</u> anomalous and provide no meaningful information for determining the 2022 forecast. The 2022 forecast for late payment charges is a function of projected payment arrearages and PGE's $4.2 million forecast is reasonable given current projections.
- Adjust account 4560001, Other Electric Revenues, to remove 2018-2021 revenue associated with PGE supporting a third-party accessing PGE equipment. As noted

above and in PGE Exhibit 200,[21] this temporary revenue is offset by incremental cost, so that neither should be included in (or used to estimate) the 2022 forecast.

- Remove detail for account 4560002, Regulatory Deferral Revenue, from the listing because it relates exclusively to Generation O&M and is part of PGE's MMA entries. These costs are irregular and provide no meaningful information for determining the 2022 forecast, which is provided in work papers to PGE Exhibit 700.
- Correct the annualization of 2021 actual revenue. Staff incorrectly multiplied 2021 actuals times two assuming it was January through June revenue. Instead, PGE's response to OPUC DR No. 557 had identified the 2021 revenue as pertaining to January through July.
- Adjust account 4560001, Other Electric Revenues, to include the CUB and Staff adjustments to the 2022 forecast that PGE accepts, as discussed above.

Q. Please summarize your response to Staff's proposal given the "Adjusted" tab of PGE Exhibit 1402.

A. The adjusted data in PGE Exhibit 1402, demonstrates that PGE's 2022 forecast is very much in line with prior year actuals and represents a reasonable forecast for Other Revenue. In conclusion, we do not accept Staff's proposal as it is based on flawed analyses that do not factor in the details necessary for accurate comparisons.

[21] PGE/200, Tooman-Batzler/9.

V. World Trade Center Lease

Q. Does AWEC propose an adjustment regarding the World Trade Center (WTC) lease?

A. Yes. In his opening testimony, AWEC consultant Dr. Lance Kaufman argues that due to the purchase of the WTC Complex by PGE's non-utility subsidiary, 121 SW Salmon Corporation (121 Salmon), the rental rate charged to PGE for space in the WTC Complex should be recalculated to include an equity value based on a forecasted future sale price of the complex in 25 years' time, and that this value should be applied to the extent that 121 Salmon's return on investment is equal to PGE's cost of capital. This would ultimately result in a negative rental rate for PGE.[22]

AWEC also asserts that PGE's rental payments have increased since the purchase of the WTC Complex by 121 Salmon and suggests that PGE's representation that the annual lease expense would not change, as provided in Docket UI 405 approving the purchase transaction by 121 Salmon of the WTC Complex, was incorrect.[23]

Q. How do you respond to AWEC's proposal and statements?

A. We recommend that the Commission reject AWEC's proposed rental price change because it is highly inappropriate to ascribe a theoretical future equity value (from 25 years into the future) to current rental payments as though the unknown future value is owed to the renter. The testimony provided below explores the fallacies of such a recommendation. Additionally, PGE refutes AWEC's assertion that PGE misrepresented information provided in Docket UI 405 and will show that AWEC is wrong in making this claim.

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[22] AWEC/200, Kaufman/36-37.
[23] AWEC/200, Kaufman/30.

Q. First, is there anything you would like to add or correct regarding AWEC's consultant's characterization of the World Trade Center in his testimony?

A. Yes. Contrary to AWEC's explanation that the WTC Complex "only exists due to PGE"[24], the WTC, originally named the Willamette Center, was actually a part of a rejuvenation process initiated by the City of Portland in the 1970s. PGE purchased the property on which the WTC Complex currently stands with the intention of building a corporate headquarters that would also house other businesses and contribute to the transformation of Portland's downtown waterfront area. The investment in the building, however, was scrutinized by the Oregon Commission and intervening parties at the time, resulting in the creation of 121 Salmon and the transfer of the building to this non-utility subsidiary prior to completion. Upon completion of the complex, 121 Salmon entered into a 65-year lease agreement with a third-party purchaser-owner with the opportunity to repurchase the building at various trigger points, with the last being year 40 of the lease agreement.

A. Reporting of Total Lease Expense

Q. AWEC states that after 121 Salmon purchased the building in 2018 from its then owner, Icahn Holding Company, PGE's annual lease payments increased due in part to the new inclusion of depreciation in the cost.[25] Is this true?

A. No. While PGE understands AWEC's confusion due to the reporting change that occurred from 2017 to 2019 in PGE's annual Affiliate Interest Report (AIR) as a consequence of the sub-lease turning into a lease (resulting in a change in accounting), PGE has always paid for its portion of depreciation associated with the WTC Complex.

[24] AWEC/200, Kaufman/29
[25] AWEC/200, Kaufman/30.

Q. Could you explain further?

A. Yes. Prior to 121 Salmon's acquisition of the WTC Complex, there was a master sub-lease agreement in place between 121 Salmon and PGE. Under this construct, 121 Salmon billed PGE the entirety of the rental expense and PGE recorded it in a non-utility account. Operating expenses, property taxes and depreciation were also incurred in non-utility PGE accounts under this structure, and then an allocation process would charge PGE's utility business for its share of the rent, operating expense, property taxes and depreciation. The total cost to PGE's utility business under this method was shown in the annual AIR under the World Trade Center Facilities section of the Cost Allocation Manual, but the financial statements for 121 Salmon under this arrangement only showed the rental expense charged to PGE under the master sub-lease agreement.

After 121 Salmon purchased the WTC Complex in 2018, the sub-lease changed to a lease, and, as a result, the accounting entries changed. From that point forward, all operating expenses, property taxes and depreciation are incurred directly by 121 Salmon, which in turn bills PGE's utility operations for their share of the rent, operating expenses, property taxes and depreciation. As such, these amounts not only appear in the AIR report under the World Trade Center Facilities section of the Cost Allocation Manual, but they are included in 121 Salmon's income statement.

Q. What was the rental expense charged to PGE in 2017?

A. PGE was charged its proportionate share, based on square footage, of $4,973,000. This was consistent with the terms of the original lease agreement.

Q. What was the rental expense charged to PGE in 2019 and 2020?

A. PGE was charged its proportionate share, based on square footage, of $2,487,000 in both 2019 and 2020. This is also consistent with the terms of the original lease agreement.

Q. What was the total lease expense, inclusive of operating expense, depreciation, and property taxes, allocated to PGE in 2017?

A. The total lease expense allocated to PGE in 2017 was $10,157,042.[26]

Q. How does this compare to the total lease expense allocated to PGE in 2019 and 2020?

A. The totals allocated to PGE were $8,933,735 and $8,521,304 for 2019 and 2020, respectively.[27] [28]

Q. Do the amounts identified above suggest that PGE's representation in Docket UI 405 that the annual lease expense would not change is inaccurate, as suggested by AWEC?[29]

A. No. Consistent with PGE's application and documentation provided in Docket UI 405, the rental payment charged by 121 Salmon has remained consistent with the terms of the original lease agreement. Due to the reduced rental payments beginning at the end of 2018, PGE's total lease payments have actually been less since 2017.

B. Ownership of the WTC

Q. Was PGE ownership considered at the time of the 2018 purchase?

A. Yes. PGE performed a high-level analysis to determine if ownership of the building by customers might be beneficial, but ultimately concluded that it was not reasonable to attempt to add the WTC Complex to rate base.

Q. What factors were considered by PGE at the time of the purchase?

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[26] Docket No. RE 64, PGE 2017 Affiliated Interest Report, Cost Allocation Manual p. 8.
[27] Docket No. RE 64, PGE 2019 Affiliated Interest Report, Cost Allocation Manual p. 7.
[28] Docket No. RE 64, PGE 2020 Affiliated Interest Report, Cost Allocation Manual p. 8.
[29] AWEC/200, Kaufman/30.

A. PGE considered that the WTC Complex as a business is unrelated to serving electric power to customers. This consideration was driven from our understanding that PGE did not currently own the building because stakeholders wished to exclude the cost of the construction of the complex from rate base when it was originally built.

PGE also considered that customers would not be interested in taking on commercial real estate risks associated with ownership of the building – specifically the risk of occupancy and the commercial lease market overall.

Q. Was there any obligation in a Commission order or in any contract associated with the WTC complex requiring PGE to first consider purchasing the building, and only if it was uneconomic, then the purchase could be made by its non-utility subsidiary, 121 Salmon?

A. No. We chose to perform an analysis to determine if it might make sense for PGE to purchase the building instead of 121 Salmon, however there was no obligation to do so, and it was our understanding that the historical position of the Commission was not supportive of PGE's ownership of the real-estate asset. In addition, we were able to confirm that there was criticism regarding the construction of the complex by the public while it was being built[30] and we confirmed that the original Commission order approving the sale-leaseback agreement in 1978 did not contemplate reacquisition of the building by PGE[31] – it only identified possible reacquisition by 121 Salmon. While we do not believe the 1978 order prohibits PGE ownership, its substance was a contributing factor to our decision not to pursue PGE ownership of the WTC Complex.

[30] Docket UF-3157, OPUC Order No. 75-832, p 32.
[31] Docket UF-3460, OPUC Order No. 78-646, p 2.

Ultimately, we did not believe it would be prudent for PGE to purchase the building, include it in current rate base, and have customers bear the various risks associated with the real-estate ownership of a city-center office building.

C. Lease Payments

Q. AWEC testimony states that "that goods and services provided by an affiliate or the non-utility operations of a regulated company should be transferred at the lower of the cost of providing the service or the prevailing market rate subject to the lower of cost or market."[32] Is this true?

A. Yes. Under OAR 860-027-0048, service provided by an affiliate to PGE must be provided at the lower of cost or market.

Q. Is there anything to add to AWEC's explanation of the function of lower of cost or market?

A. Yes. In addition to the section highlighted by AWEC, NARUC Guidelines state:

> The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization.[33]

Q. Is 121 Salmon providing a service to PGE where "market forces do not necessarily drive prices" resulting in self-dealing that could unfairly result in an overcharge to customers?

[32] AWEC/200, Kaufman/27
[33] National Association of Regulatory Utility Commissioners, Guidelines for Cost Allocations and Affiliate Transactions, Exh. AWEC/202.

A. No. Market prices drive the rental rates for office space in downtown Portland. 121 Salmon uses comparable rental rate data from the area to determine rental rates for its non-utility tenants, while PGE is charged the amount from the original lease agreement set in 1978.

Q. Is 121 Salmon inappropriately shifting costs from its non-regulated competitive operation to PGE?

A. No. The rental rate charged to PGE is approximately 80% below the market rate charged to other non-utility tenants of the building, and PGE is only charged for its proportionate share of the use of the building as determined by square footage. Further, this share will decrease when PGE employees move to the IOC, which results in a decrease in WTC lease expense in the 2022 test year forecast as discussed in PGE Exhibits 400 and 800. Other costs associated with PGE's lease, consistent with the original lease agreement, are charged to PGE at cost. These charges are also consistent with comparable leases, where such costs are included in the operating expense portion of a tenant's rent.

Q. AWEC recommends "reducing the transfer price for the rent of the WTC to a level that sets the Affiliate's *expected* [emphasis added] return on investment to PGE's cost of capital."[34] What is meant by "expected?"

A. As shown in AWEC's analysis, "expected" means a theoretical amount 121 Salmon might be able to obtain from selling the WTC Complex in another 25 years' time when the current lease reaches its end.

Q. Why does AWEC select a point 25 years from now for calculating an "expected return on investment?"

[34] AWEC/200, Kaufman/26.

A. AWEC opportunistically selects a theoretical equity value from 25 years from now because that is the point when the value of the WTC Complex will no longer be encumbered by the current low-rate lease with PGE.

Q. Does this mean that the equity value of the WTC Complex right now continues to be encumbered by the low-rate lease with PGE?

A. Yes.

Q. Has 121 SW Salmon entered into any agreements to sell the WTC Complex in 25 years' time for a pre-determined price?

A. No.

Q. Is 121 Salmon required to sell the WTC Complex in 25 years' time?

A. No. There is nothing that requires 121 Salmon to sell the WTC Complex in 25 years.

Q. Is it known that 121 Salmon will sell the WTC Complex in 25 years' time?

A. No. This is a decision that would need to be analyzed approximately 25 years from now. Given the volatility of real-estate values that could occur over the next 25 years, it would not be prudent or reasonable for 121 Salmon to make such a determination at this time.

Q. Given that there is no meaningful evidence to support 121 Salmon's intention to sell the WTC Complex in 25 years' time (or at any other time), is it appropriate to use a theoretical, inflated equity value in a calculation of the cost of service to PGE?

A. No. It is not appropriate to set a transfer price for any goods or services based on an unknown future value that has not and may not ever be realized.

Q. What is 121 Salmon's current return on investment?

A. For 2020, 121 Salmon's return on equity was equal to 3.43%.[35] 121 Salmon does not currently hold any debt.

Q. Is 3.43% above PGE's authorized cost of capital?

A. No, it is below PGE's cost of capital of 6.81% and well below PGE's return on equity of 9.50%, as stipulated by Parties in this GRC.

Q. Does 121 Salmon intend to raise the rental rate to PGE in an effort to obtain a return equal to PGE's rate of return?

A. No. The rental rate will remain the same amount as originally established in the 1978 lease agreement and as recently approved by Commission Order No. 18-323 (Docket UI 405).

Q. What rental rates were established in the original lease agreement?

A. In 1978, 121 Salmon sold the building in a sale leaseback agreement to a third-party and the agreement guaranteed the rental rates as shown in Table 2, below. The below-market rates were established, in part, because 121 Salmon, not the owner, would be assuming the occupancy risk for the complex.

Table 2
Rental Payments in the Original
WTC Lease Agreement

Initial Lease Term			Extension 1	Extension 2	Extension 3
1978-1979	1979-2004	2004-2018	2018-2028	2028-2038	2038-2043
$3.385 M	$5.137 M	$4.973 M	$2.487 M		

Q. Were PGE customers exposed to occupancy risk during the 40-year period when the building was owned by a third-party?

A. No. The risk was entirely assumed by PGE's shareholders.

Q. Please describe 121 Salmon's recent challenges with occupancy risk, if any.

[35] See PGE confidential work paper "121 Salmon_ROE_2020_CONF".

A. Due to the COVID-19 pandemic and social unrest in the past couple of years, it has been more challenging to occupy all the space in the WTC Complex. Even now, more businesses are choosing to allow their employees to work from home reducing the need for office space, plus the WTC Complex is located next to the Federal Courthouse, which has been the epicenter of disturbances in downtown Portland over the past couple of years.

Q. Have PGE customers ever been exposed to the occupancy risk or other ownership risks associated with the WTC Complex?

A. No. 121 Salmon, and therefore PGE's shareholders, have always borne the risks associated with owning the building including the risk of leasing the space available to its full capacity.

Q. Have customers ever paid for ownership of the WTC complex through rate base?

A. No. The complex was sold to a third-party prior to opening in 1978 and was <u>never</u> included in PGE's rate base.

Q. In a standard real estate transaction, is there an obligation for the real-estate owner to provide a portion of equity to its renter? If no, why not?

A. No. Not only has the renter not paid for or taken on the risks associated with ownership, but equity value is extremely subjective and cannot be known until the property has been sold. As explained above, 121 Salmon does not even know if it will sell the building in 25 years let alone the amount that could be received.

Q. AWEC asserts that customers are entitled to a future potential equity value of the building because 121 Salmon purchased the building for a discounted amount due to the lease agreement encumbering the value of the complex. Is this appropriate?

A. No. A renter is not entitled to an assumed future equity value associated with ownership *because* they enjoyed and will continue to enjoy a discounted rental price for 65 years. The renter has and is already benefiting from the discounted rental price (as illustrated by 121 Salmon's current return). To use the benefit already being received as a reason to be entitled to additional benefits is illogical, especially when the renter has never been subject to the risks associated with ownership.

Q. Does AWEC's analysis include assumptions regarding the value of the below-market rental prices that have been charged to PGE for the past 40 years and the continuing below-market rental prices that will be charged for the next 25 years?

A. No. AWEC's analysis is flawed in that it does not include such assumptions. We do not correct these errors, however, because their entire analysis is fundamentally flawed in that it is based on the notion that current renters, who have never owned and have never shouldered any of the risks associated with ownership, are entitled to equity that cannot be realized for 25 years or more.

Q. If 121 Salmon had not purchased the building, would PGE be subject to a lower lease payment?

A. No. Ownership of the WTC Complex by an unaffiliated third-party versus ownership by an affiliated third-party does not and did not result in a more beneficial rental price to PGE. PGE and our customers continue to enjoy a lease rate well below market, consistent with the terms of the original lease agreement.

Q. What is your recommendation to the Commission regarding the adjustment proposed by AWEC for WTC lease expense?

A. We recommend the Commission reject AWEC's proposal. AWEC's attempt to seize a theoretical future equity value related to the WTC Complex is wholly inappropriate for multiple reasons.

First, ownership of the WTC Complex has never been paid for by customers through rate base or any other means. As a result, customers have never been exposed to the risks, particularly the occupancy risk, associated with owning real-estate. PGE's utility business, as a current renter of the WTC Complex, is not owed a future unknown equity value of this real estate asset.

Second, the equity value of the WTC Complex continues to be encumbered by the incredibly low rental rate enjoyed by PGE's utility business, there is no evidence of a sale in 25 years' time, and any applicable equity value would need to be known and realized for a return on investment to be calculated.

Lastly, PGE's utility operations have rented the building from third parties since 1978 at a reduced rate, and they are continuing to do so. 121 Salmon is also a third party that is maintaining the same below-market rental rate for PGE as would be enjoyed if any other third party owned the complex. Demanding additional value after benefiting from below market rates for 65 years, at the time when the affiliate is currently earning a return of less than half of the utility's authorized return on equity, is out of alignment with the rules and guidelines on affiliate transactions.

VI. Colstrip

Q. What issues have Parties raised regarding PGE's Schedule 146 proposal for Colstrip?

A. Staff, CUB, and AWEC have raised issues regarding the mechanics of PGE's proposed Schedule 146 modifications. Both CUB and AWEC propose that, in addition to updating decommissioning amounts on an annual basis, PGE should also update net plant amounts and the associated return on investment annually. Staff proposes that all three parts of PGE's proposed tariff be updated any time that Part C of the tariff is updated, or annually, whichever occurs sooner.

Q. How does PGE respond to Parties' proposals for Schedule 146?

A. Parties have resolved this issue in the Second Stipulation.

Q. Please describe AWEC's issues with PGE's treatment of Colstrip depreciation.

A. AWEC raises three primary issues with PGE's treatment of depreciation for Colstrip, which are as follows:

1. PGE has not included the benefit of incremental depreciation reserves in its filing;
2. PGE has made an error in how incremental depreciation expense is forecast for Colstrip; and
3. PGE has errors in its calculation of depreciation reserves.[36]

Q. How do you respond to AWEC's argument regarding incremental depreciation benefits?

A. AWEC appears to be arguing that PGE should be setting rate base to a date beyond May 1, 2022. AWEC's argument on this issue has no merit. Setting PGE's net plant amount to a date beyond PGE's rate effective date is in conflict with the Commission's interpretation of

[36] AWEC/100, Mullins/32-36.

the used and useful standard in Oregon. While AWEC suggests this is somehow appropriate for one element of Colstrip rate base, they do not suggest this is appropriate treatment for PGE's overall rate base. Additionally, regardless of the appropriateness and legality of this suggestion, tax normalization rules prohibit this type of treatment. Finally, the Second Stipulation provides for Colstrip rate base, along with all other Colstrip costs, to be updated on an annual basis.

Q. Has PGE made an error in forecasting incremental depreciation expense, as AWEC claims?

A. No. Colstrip's depreciation expense calculation assuming straight line depreciation is consistent with the treatment used for all other PGE plants that have an end-of-life date. PGE has consistently used straight-line depreciation expense based on the probable retirement date of assets for many years. For example, PGE's Boardman plant, prior to retirement, was depreciated using straight line depreciation from 2010 (the year in which its early retirement date was established) through 2020 (the year in which Boardman was retired from service). Colstrip has been on straight line depreciation since 2018, the year in which a probable retirement date was effectuated in customer prices. As such, it is reasonable, consistent with prior treatment, and consistent with how PGE records Colstrip depreciation on its books to continue to include straight line depreciation for Colstrip in this filing.

Q. PGE bases depreciation on the net plant balances of assets. Is this treatment consistent with rates used in PGE's depreciation study in Docket UM 2152?

A. Yes. For decades, PGE has depreciated its tangible utility assets based on net plant rates and the treatment for Colstrip is no different. PGE's net plant rates per Table 2 of PGE's depreciation study are translated directly from, and thus based on, the gross plant rates included in Table 1 of PGE's depreciation study. Additionally, contrary to AWEC's arguments, PGE records depreciation expense on its books based on net plant balances and so our method for forecasting test year expense is consistent with actual expense.

Q. How does PGE respond to AWEC's position that a separate accrual for decommissioning expense is not necessary?

A. The net salvage rates included within PGE's Docket UM 2152 depreciation study do not include decommissioning expenses related to the Colstrip asset retirement obligation (ARO). The net salvage rate only covers non-ARO related decommissioning costs. This is precisely why Colstrip's decommissioning accrual is separate within PGE's depreciation study.

Q. Has PGE overstated the depreciation expense amount for Colstrip?

A. No. AWEC states that PGE has overstated depreciation expense by approximately $7.9 million based on their calculation of Colstrip's composite depreciation rate against Colstrip's total gross plant.[37] However, AWEC's calculation is incorrect. As we state above, it is appropriate to forecast Colstrip depreciation expense on a straight-line basis to the probable retirement date and using net plant balances. Therefore, AWEC's calculation of depreciation expense is oversimplistic and not consistent with how PGE has historically recorded depreciation expense for the Colstrip plant on its actual books.

Q. Does PGE include the correct reserve balances for Colstrip?

A. Yes. AWEC argues that PGE has errors in its calculation of depreciation reserves based on PGE's response to AWEC DR Nos. 206 and 208.[38] However, AWEC is taking these two data responses out of context and thus incorrectly conflating the responses provided to these two different requests. The different accumulated depreciation amounts provided in response to

[37] AWEC/100, Mullins/35.
[38] AWEC/100, Mullins/35.

these DRs are not in conflict, as they are provided in response to two fundamentally different questions. PGE's response to AWEC DR No. 206[39] provides the forecasted Colstrip Steam plant accumulated depreciation as of April 30, 2022, without the adjustment for AROs. This view of accumulated depreciation looks only at the pure depreciation component of rate base in order to calculate depreciation expense, which was the question asked in AWEC DR No. 206. However, AWEC DR No. 208[40] relates to the measurement of Colstrip rate base, in which plant in service and accumulated depreciation includes adjustments for AROs. Thus, the accumulated depreciation amount of approximately $380.1 million referenced in PGE's response to AWEC DR No. 208, which asked for total plant balances, appropriately includes the ARO adjustment.

[39] Provided here as PGE Exhibit 1406.
[40] Provided here as PGE Exhibit 1407.

VII. Payroll Tax

Q. Please discuss Staff's concern with PGE's payroll tax forecast.

A. Staff is concerned that PGE's payroll tax forecast, in addition to being calculated by using PGE's wages and salaries forecast, also includes amounts calculated from PGE's incentive forecast.[41] As such, Staff proposes to remove a portion of payroll tax expense from PGE's request and adjust rate base to account for incentive-related payroll taxes loaded to capital. In support of their proposal, Staff references Commission Order No. 14-422,[42] in which the Commission adopted a stipulation between parties agreeing that PGE would reduce rate base by $10 million to resolve all issues regarding past capitalization of incentives and that "(b)eginning in 2015, PGE will not capitalize financial performance based incentives."[43]

Q. Is PGE currently capitalizing financial performance-based incentives?

A. No. PGE currently separates performance-based incentives from both actual and budgeted amounts, so that only a portion of non-financial based incentives are loaded to capital.

Q. Is Order No. 14-422 relevant to PGE's payroll taxes?

A. No. This order pertains to capitalized incentives and makes no mention of payroll taxes or any other category of costs. Payroll taxes are a prudently incurred cost of providing utility service. PGE is required to pay a variety of payroll taxes based on amounts included within employee paychecks, with the largest being the Federal Insurance Contributions Act (FICA) payroll tax that funds Social Security and Medicare. Payroll taxes are not discretionary expenditures.

Q. Is there Commission precedent regarding the forecast and collection of payroll taxes?

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[41] Staff/200, Fox/23.
[42] Staff/200, Fox/24-25.
[43] Commission Order No. 14-422, Appendix B, page 2.

A. PGE is unaware of any Commission order or ruling that has disallowed payroll tax amounts or suggested that certain payroll taxes cannot be included within utility plant. As discussed above, the order that Staff cites (Order No. 14-422) makes no mention of, nor has any bearing on, PGE's treatment of payroll taxes.

Q. Is PGE's forecast and actual treatment of payroll taxes somehow unique?

A. Not at all. PGE calculates and pays taxes based on employee earnings in accordance with federal, state, and local regulations. There is nothing unique in how PGE treats the payroll taxes resulting from employee earnings. While Staff presents this as some form of incentive recovery, the facts do not bear this out. These amounts are not wages, salaries, incentives, or payments of any kind to employees. These are federal, state, and locally imposed taxes that PGE is responsible for paying in support of providing service to customers.

Q. Irrespective of the merits and basis of Staff's argument, is Staff's adjustment to rate base for prior periods appropriate?[44]

A. No. Not only is the entirety of Staff's argument baseless and without precedent, but the prior period rate base adjustment also proposed by Staff is retroactive ratemaking. As stated in Commission Order No. 17-482 "the rule against retroactive ratemaking prohibits a utility regulator from setting rates that allow a utility to recover past losses or require it to refund past profits. The rule is primarily derived from the fact that ratemaking is a legislative act and is applied prospectively absent explicit legislative direction to the contrary."[45] Yet it appears Staff is proposing just that: a punitive adjustment for prior rate base amounts they argue should not have been included.

Q. Are the assumptions Staff uses to calculate payroll tax amounts accurate?

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[44] Staff/200, Fox/25.
[45] Commission Order No. 17-482, page 7.

A. No. While PGE disagrees with the basis for and entirety of Staff's proposal, we believe it is also important to point out some incorrect assumptions Staff used to calculate the proposed amounts. In particular, Staff's assumption that the gross amount of payroll taxes is already net of non-utility and co-owned entity calculations[46] is incorrect. The allocation credit amount in account 4081009 reduces PGE's payroll tax expense for amounts loaded to capital and for affiliate and co-ownership payroll taxes. As such, Staff's allocation percentage used in Staff Exhibit 200, Table 2 is calculating an amount that is greater than both the expense portion and the capital-related portion of these tax amounts. Correcting for this would reflect an expense amount of $754,719 and a capital amount of $551,182. Additionally, Staff's assumption for amounts included in PGE's rate base as of May 1, 2022 is also incorrect, as Staff ignores the impact of accumulated depreciation on PGE's net plant balance. Factoring this in would significantly reduce any calculation of rate base amounts.

Q. Please summarize PGE's position on Staff's proposal for payroll taxes.

A. PGE's payroll taxes are a prudently incurred cost of providing service to customers. The payment of these taxes is in accordance with Federal, State, and Local laws and regulations and there is no Commission Order or precedent that indicates any portion of these prudently incurred costs may or should be disallowed.

[46] Staff/200/page 24/lines 11-13.

VIII. Allocation of Smart Grid Costs

Q. What issues have Parties raised in relation to PGE's allocation of smart grid costs?

A. Staff proposes to allocate $10 million or 10% of the Customer Touchpoints capital project to the Generation function and out of the Distribution, Billing, Metering, and Other Consumer functions.[47] Staff cited the stipulation in Docket UE 335 as a basis for this adjustment and their agreement with CUB's proposal that a portion of smart grid assets be allocated to the Generation function.[48] Staff also supports CUB's recommendation for a third-party study on how to allocate smart grid costs as proposed in CUB Exhibit 200 in Docket UE 335.[49]

Q. Do you agree with Staff's proposal and overall concept?

A. No. We disagree and will address the overall concept first and then address how it might apply to Customer Touchpoints.

Q. How does PGE allocate smart grid costs?

A. 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[50] 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.

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[47] Staff/1400, St. Brown/16.
[48] Staff/1400, St. Brown/16.
[49] Staff/1400, St. Brown/16.
[50] General plant consists of physical assets that do not fall under the other FERC definitions of assets, such as structures, computer hardware, and communication equipment. Intangible plant represents non-physical assets, the largest category being computer software.

However, PGE does not maintain a category of Smart Grid assets for separate functionalization. Because much of smart grid relates to customer-owned equipment that is behind the meter (e.g., solar panels and electric vehicle chargers), much of PGE's smart grid investment relates to distribution infrastructure to integrate this equipment with our system. Hence, this investment is recorded to Distribution assets, as defined by the FERC Uniform System of Accounts, and assigned to the Distribution function. If the smart grid investment represents general and intangible plant, then PGE will functionalize individual assets, if they are large and separately identifiable but not directly assigned. In such cases, PGE will establish a basis for allocation. An example of this is the IOC where PGE allocated its cost based on the 2022 labor forecasted to occupy it. As noted above, other components of G&I smart grid will be allocated based on O&M labor.

Q. What specifically does this mean regarding smart grid assignments or allocations to Generation?

A. This means that PGE already assigns or allocates the following costs to the Generation function:

- Based on the 2022 labor forecasted to occupy the building, PGE allocated 31.6%, or approximately $68 million, of IOC gross plant to Generation.
- Based on O&M labor, PGE allocated 22.1% of Other G&I plant that is not separately identifiable to Generation. Although we do not identify or track a specific category of smart grid plant as part of this G&I plant, we note that approximately $86.1 million in computer hardware and communication equipment, as well as approximately $93.2 million of gross intangible plant (i.e., computer software) are allocated to the Generation function.

- PGE currently assigns approximately $13.3 million of demand response costs to Generation through PGE Schedule 135. Further, this cost will increase as the demand response goal is expected to grow from the current 68 MW to 211 MW of capacity by 2025, as noted in PGE Exhibit 600.

Q. Do you agree with Staff's proposal regarding Customer Touchpoints?

A. No. PGE agreed to allocate 10% of the Customer Touchpoints capital project to the Generation function in Docket UE 335 for settlement purposes in that case, but we do not agree on the overall appropriateness of this entry and did not carry it forward to Docket UE 394. First, Customer Touchpoints is not a production asset. Instead, the Customer Touchpoints project primarily consisted of replacing two large software systems: a customer information system and a meter data management system (MDMS). At a very high level, these systems' core functions are to process PGE's meter data from the advance metering infrastructure system (AMI) and convert that to customer billings. In addition, these systems support more varied pricing options and provide customers with more choices, services, and opportunities for interaction than were available with the legacy systems.[51]

Although Customer Touchpoints provides a platform for smart grid services (e.g., demand response), it does so in the form of processing meter data, converting that to billings, and providing customer service options. Consequently, PGE allocates Customer Touchpoints to the Metering, Billing, and Other Consumer functions. We also allocate a portion to the Distribution function since PGE's meters are assigned to the Distribution function and the MDMS communicates directly with AMI.

[51] PGE's Customer Touchpoints project was otherwise referred to as the Customer Engagement Transformation initiative and discussed in the following PGE general rate cases: UE 262 (2014), UE 283 (2015), UE 294 (2016), UE 319 (2018), and UE 335 (2019). The projects closed to plant in 2018 and have been in rate base since with 10-year depreciable lives.

Q. Please summarize your response to Staff's proposal.

A. PGE correctly functionalizes costs based on assignments and allocations in accordance with the requirements of OAR 860-038-0200, and an appropriate portion of smart grid costs are already applied to the Generation function. Consequently, we believe that: 1) allocating a portion of Customer Touchpoints to Generation is inappropriate and the specific proposal of 10% or $10 million is arbitrary and without support; and 2) a third-party study of smart grid allocations is unnecessary at this time.

IX. Level III Outage Restoration Mechanism

Q. Please summarize the issues regarding PGE's Level III Outage Restoration Mechanism.

A. In direct testimony, PGE proposed to modify the current asymmetric mechanism into one that allows negative balances, but would be limited by maximum balances, and would entail PGE sharing costs with customers (for specific details see PGE Exhibit 800, Section VII). In response, Parties have not accepted PGE's proposed revisions but instead offer individual recommendations and arguments, which we discuss below.

Q. Does the Second Stipulation address any issues relevant to the Level III Outage Restoration Mechanism?

A. Yes. The parties agreed to remove the February 2021 Ice Storm from the calculation of the Level III outage accrual and to support or not oppose authorization of the February 2021 Ice Storm deferral in Docket UM 2156. The parties also agreed to the re-establishment of approximately $8 million to the Level III Reserve, which had previously been reduced by that portion of the 2021 February Ice Storm expenses and not included in PGE's initial filing in Docket UM 2156.

Q. Please describe AWEC's position.

A. AWEC argues that "A storm balancing account continues to be unnecessary and unwarranted."[52] They claim that PGE has not presented new evidence that would justify revisiting the Commission's past rejection of a storm cost balancing account.[53] AWEC also criticizes the evidence PGE presented regarding increasing storm intensity, stating, "PGE cites 'two recent examples [that] involve non-winter wind events' and then includes general

[52] AWEC/100, Mullins/39.
[53] AWEC/100, Mullins/39.

quotations from the Fourth National Climate Assessment. This is not foundational analysis or demonstration of any chain of causation."[54]

Q. How do you respond to AWEC's position and assertions?

A. We disagree with AWEC's position because the information on which they rely is inaccurate and incomplete. Specifically, AWEC claims that PGE provided two examples to demonstrate greater storm *intensity* due to climate change. However, PGE's statement was that "While winter storms have typically been the most common type of Level III event, we are witnessing *a greater variety of events* and events with greater intensity *than were contemplated in Docket UE 215*" (emphasis added).[55]

Q. What do PGE's two examples indicate?

A. They were examples to indicate a change that cannot be reasonably measured or proven over a short time frame. PGE Exhibits 1403 and 1404, however, provide further evidence of this change. In PGE Exhibit 1403, we list the restoration events as provided in PGE's UE 215 work papers (updated to reflect winter versus non-winter events). Exhibit 1403 indicates that from 1979 through 2008, 13 of the 14 restoration events were winter events. In contrast, PGE Exhibit 1404 lists the Level III events from 2014 through year-to-date 2021. Of the 18 listed events in Exhibit 1404, half are non-winter events, and this list does not include the Labor Day 2020 wildfire emergency. This evidence indicates that over time, the causes of restoration events are changing.

Q. Did PGE suggest that its two examples provide support for greater storm intensity?

A. No. PGE's two examples were primarily examples of the changing causes of Level III events, and not increasing costs, as evidenced by the fact that PGE did not discuss costs as part of

[54] AWEC/100, Mullins/39.
[55] PGE/800, Bekkedahl-Jenkins/66.

those examples. To see an indication of the increase in intensity, however, we provide PGE Exhibit 1405, which lists the costs of Level III events from 1996 through 2021 year-to-date.[56] From this data, we can see that 57% of the total nominal costs and 50% of the real costs have been incurred in just the past eight years of the 26-year period. We also note that Staff's testimony does not disagree that the number of events also appears to be increasing as they observe that "since 2014, [PGE] has had 1.75 Level III Storm events per year whereas, from 1979 to 2008, it had 0.48 storm restoration events per year."[57]

Q. Do your referenced exhibits indicate that PGE has experienced a greater variety of events and events with greater intensity?

A. Yes. The exhibits provide reasonable indications that these types of changes are occurring. They also coincide with the information provided by the Fourth National Climate Assessment (Assessment), which is a foundational study, contrary to AWEC's assertion. We note that AWEC did not provide any studies that contradict the Assessment, but instead summarily dismissed it, presumably because of their own lack of evidence.

Q. Does Staff support PGE's proposed revision to the Level III mechanism?

A. No, Staff recommends rejecting PGE's proposal.[58] Staff applied a Mann-Kendall Test to determine whether PGE's recent experience with Level III events has a monotonic upward or downward trend.[59] Their conclusion from this analysis is that, "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."[60] Staff also notes that, "In its response to Staff DR 400 PGE asserts that since 2014,

[56] PGE Exhibit 1405 excludes the 2020 Labor Day 2020 wildfire emergency and the February 2021 ice storm emergency, which although they were quite severe and intense, are to be addressed as part of separate emergency deferrals.
[57] Staff/1400, St. Brown/7
[58] Staff/1400, St. Brown/9.
[59] Staff/1400, St. Brown/6-7.
[60] Staff/1400, St. Brown/6.

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."[61]

Q. How do you respond to Staff's Mann-Kendall Test results?

A. Staff's analysis evaluates only one variable (cost) and includes too little time-series data with which to evaluate a longer-term trend caused by climate change. As a result, it is not surprising or meaningful that Staff's results fail to reject the null hypothesis that there is no trend. In contrast, PGE Exhibits 1403, 1404, and 1405 provide detail over a longer period of time and from different perspectives.

Q. Does Staff offer any proposals in spite of their Mann-Kendall Test results?

A. Yes. Staff observed that there is a "beneficial incentive for PGE to harden its system to avoid actual Level III events costs in excess of the 10-year average."[62] And although Staff recommends rejecting PGE's proposal to let the Level III Storms balancing account go negative, they propose: "to help PGE better recover costs in an environment of increasing frequency of storms, Staff proposes to update the 10-year average annually."[63]

Q. Does CUB offer any proposals to revise the Level III mechanism?

A. Yes. CUB recognizes the "the dynamic nature of future storm costs"[64] and proposes a revision to PGE's mechanism that would comprise: 1) a negative balance in the reserve account; 2) the negative balance of the balancing account cannot exceed two times the ten-year average accrual, which establishes a hard cap on the Level III storm mechanism; and 3) any level III

[61] Staff/1400, St. Brown/7.
[62] Staff/1400, St. Brown/9.
[63] Staff/1400, St. Brown/9-10.
[64] CUB/200, Gehrke/19-20.

costs incurred by PGE that are past the hard cap are not to be recovered from customers (i.e., there is no sharing between PGE and customers).[65]

Q. How do you respond to Staff's and CUB's proposals?

A. We appreciate Staff's and CUB's offers for revising PGE's Level III mechanism. We believe these proposals reflect the understanding that climate change is a reality and that there is much complexity and uncertainty with regard to its impacts on Level III events. For example, Staff's proposal recognizes that in spite of the Mann-Kendall Test results, an increasing frequency of storms is a real possibility,[66] and CUB states that "Provided that the storm balancing account has a hard cap, CUB is also supportive of a storm balancing account that is allowed to go negative."[67] However, PGE maintains that PGE Exhibit 800 addresses all the issues the Commission requested in Order No. 19-247 and that PGE's proposed mechanism reflects a reasonable balance of cost sharing and maximum amounts (caps) for the balancing account. Although we do not advocate for an alternative to PGE's initial proposal, we note that CUB's proposal of a balancing account and specified hard caps coupled with Staff's proposal of annual updates represents a reasonable alternative for the Commission to consider if the Commission is not inclined to adopt PGE's proposal.

Q. Have Parties raised any additional issues regarding PGE's Level III mechanism?

A. Yes. CUB states that "Under Commission Order No. 10-478, PGE and other parties agreed to create the current mechanism to enable PGE to recover storm damage costs. The Company seems to be under the impression that this mechanism is designed to potentially recover wildfire costs. CUB would like to be clear that this mechanism has been designed to recover

[65] CUB/200, Gehrke/19.
[66] Staff/1400, St. Brown/9.
[67] CUB/200, Gehrke/20.

costs associated with storm damage."[68] In addition, Staff observes that "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."[69]

Q. How do you respond to these assertions about wildfires?

A. We believe they are in error. Staff itself responds to CUB's assertion by stating:

> 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. 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 (emphasis added).[70]

The key point here is that the Level III mechanism applies to "severe outage events," and more importantly, that a Level III event is defined by meeting the outage criteria – <u>not</u> by the cause of the outage event. There is nothing in the UE 215 stipulation or Order No. 10-478 that excludes Level III events caused by wildfires.

Unfortunately, Staff mischaracterizes PGE's deferral application in Docket No. UM 2115, which pertained to the 2020 Labor Day wildfire emergency. In that filing, PGE stated that it "proposes to <u>not</u> apply the wildfire emergency costs to the Level III outage reserve" (emphasis in original).[71] This assertion, however, only applied to that emergency event because "a more comprehensive mechanism to address a wider range of significant

[68] CUB/200, Gehrke/20.
[69] Staff/1400, St. Brown/5.
[70] Staff/1400, St. Brown/2.
[71] PGE Clarification of Application for Deferred Accounting, UM 2115, October 8, 2020, page 3.

events and system emergencies … is not currently available."[72] In fact, such a mechanism does now exist and is in place for PGE based on Commission Order Nos. 21-259 and 21-309. This means that declared emergencies such as the 2020 Labor Day wildfire are to be addressed by deferral and not by the Level III mechanism. What this also means is that wildfires that are not declared emergencies would in fact apply to the Level III mechanism, if the Level III criteria are met. Again, there is nothing specifically precluding wildfire restoration costs from being applied to the Level III mechanism, if the events meet the Level III criteria and are not part of declared emergencies.

[72] Ibid.

X. Flexible Load Plan

Q. Have Parties raised issues regarding PGE's Flexible Load Plan (FLP) as discussed in PGE Exhibit 600?

A. Yes. Both CUB Exhibit 200 and Staff Exhibit 2000 discuss PGE's FLP. CUB raises two issues regarding FLP but they do not produce any specific impacts to this GRC. Staff recognizes topics for discussion regarding the FLP but does not offer opinions on them as they do not directly relate to this rate case. Instead, Staff prefers to address FLP issues at the time they are formally proposed.

Q. What are CUB's issues?

A. CUB's first issue is when updates would be allowed for PGE's proposed cost recovery mechanism.[73] CUB's second issue relates to the potential of providing a return on FLP costs and the validity of such an incentive.[74]

Q. How do you respond to CUB's issues?

A. PGE believes that discussions about updates, return on FLP, or regulatory shift should be included in a future GRC because: 1) PGE has not made any proposals regarding these issues in Docket UE 394; and 2) there is not sufficient context or detail on which the Commission can make a determination at this time.

Q. Please summarize the status of FLP in this general rate case.

A. PGE introduced FLP in this GRC at the request of Parties, but based on Staff's comments and our observations above, FLP is most appropriately addressed in Dockets UM 2141 and/or UM 2005.

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[73] CUB/200, Gehrke/10.
[74] CUB/200, Gehrke/10-11.

XI. Other Issues

Q. Do you have any final observations regarding the revenue requirement adjustments by the Parties?

A. Yes. We have compared the revenue requirement models and adjustments of Staff, CUB, and AWEC to PGE's revenue requirement calculations and effectively tie to their results with the following exceptions:

- PGE does not make revenue requirement entries for load forecast changes similar to AWEC adjustments A-3 and A-4. Changes to the load forecast impact customer prices entirely differently than changes to the revenue requirement and cannot be reflected in the manner depicted by AWEC.
- CUB's calculation of converting a cost adjustment into revenue requirement incorrectly grosses up the adjustments for taxes. Because revenue is adjusted equal to the expenses, there is virtually no tax effect.[75] The only gross-up that occurs is for revenue sensitive costs such as franchise fees and uncollectibles.
- In Staff Exhibit 100, Staff lists the adjustment from the UE 391 stipulation as a $6.5 million reduction to NVPC. In total, the UE 391 stipulation results in an $8.1 million reduction: $1.8 million of which settled four specific issues, and $6.3 million of which settled all remaining issues.
- In Staff Exhibit 200, Staff incorrectly claims that "The Company states that Colstrip isolated revenue requirement comprises $55.9 million of the $59 million base rate increase."[76] We note, however, that the Colstrip revenue requirement is already in

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[75] The sole impact from taxes is based on the derivation of return on working cash that is applied to each expense.
[76] Staff/200, Fox/5

base rates, is not incremental, and is not a component of the UE 394 rate increase. In summary, PGE's proposal is to separate Colstrip from base rates, not add to them.

- In AWEC Exhibit 100, AWEC claims that "PGE's revenue requirement proposal is not entirely consistent"[77] due to the timing of the test year forecast and the date used to establish rate base. In fact, PGE is consistent with prior GRCs, where a calendar year is used for the test year and rate base is established as of the date just prior to the GRC's rate-effective date. We then normalize and adjust applicable costs as discussed in PGE Exhibit 200, Section III, page 12, lines 1-17, so that concerns such as AWEC's are properly addressed.
- In AWEC Exhibit 100, AWEC recommends that "new projects be excluded from the proforma capital considered in this proceeding, since they were not included in PGE's application and there has been no opportunity to review the projects."[78] PGE does not advocate that new projects be specifically added to rate base. However, PGE's rate base forecast reflects the best information available at the time of filing and updates to that forecast will always provide more current information. What this means is that: 1) a rate base forecast is a non-static variable that will reflect reasonable changes in expenditure as new information becomes available; and 2) the filed amount is still reasonable knowing there are the inevitable changes. The exception to this is if a significant addition to plant is not expected to be on-line by the GRC rate-effective date. In such instances, an adjustment to rate base is appropriate.

[77] AWEC/100, Mullins/17
[78] AWEC/100, Mullins/19

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
1401	PGE Current Revenue Requirement
1402	Other Revenue Analysis
1403	1979-2008 Events
1404	2014-2021 Events
1405	1996-2021 Event Costs
1406	PGE’s response to AWEC Data Request No. 206
1407	PGE’s response to AWEC Data Request No. 208

Exhibit 1401 is voluminous in
size and provided only in
electronic format

PGE Exhibit 1402

Account	Account Description	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Jan-Jul Actuals	2022 Test Year
4470003	SalesfrResale-IntertiePGEtoPGE	($5,936,823)	($6,256,410)	($6,946,711)	($7,312,968)	($7,067,265)	($4,583,534)	($7,180,000)
4500001	Forefeited Discounts	($2,994,617)	($3,415,327)	($6,004,495)	($7,533,569)	($1,510,490)	($784,260)	($4,191,873)
4510001	Miscellaneous Service Revenues	($1,852,377)	($1,830,779)	($1,193,165)	($1,918,764)	($917,276)	($353,386)	($2,096,529)
4540001	Rent From Electric Property	($1,025,319)	($1,206,299)	($1,714,801)	($1,271,846)	($1,453,820)	($854,459)	($1,204,074)
4540002	RentFrElecProperty-Joint Pole	($7,679,162)	($6,444,068)	($7,374,023)	($10,582,480)	($12,375,540)	($6,738,791)	($13,294,368)
4560001	Other Electric Revenues	($3,648,451)	($3,825,497)	($4,699,484)	($7,581,609)	($7,028,841)	($3,617,788)	($1,191,300)
4560002	OthElecRev-RegulatoryDeferRev	$517,749	$1,809,924	$2,075,290	$43,063	$3,252,694	$0	$4,763,984
4560003	OthElecRev-FishWildlifeRecrOps	($12,386)	($11,234)	($12,311)	($13,829)	($16,397)	($10,788)	($12,757)
4560012	OthElecRev-Steam Sales	($1,480,085)	($1,892,218)	($2,160,358)	($1,874,091)	($1,419,239)	($1,241,826)	($1,915,238)
4561001	TransRevOthers-Non-Intertie	($2,899,444)	($3,557,592)	($3,518,555)	($3,412,285)	($3,659,943)	($2,125,854)	($3,531,415)
4561002	TransRevOthers-Intertie	($5,080,702)	($4,953,843)	($7,042,193)	($7,026,637)	($6,945,362)	($4,020,546)	($6,672,000)
5660002	TransOp-MiscExp-IntertieWhePGE	$5,936,823	$6,256,410	$6,946,711	$7,312,968	$7,067,265	$4,583,534	$7,180,000
		($26,154,793)	($25,326,933)	($31,644,096)	($41,172,048)	($32,074,214)	($19,747,696)	($29,345,569)

PGE Exhibit 1402

Account	Account Description	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Annualized Actuals*	2022 Test Year
4470003	SalesfrResale-IntertiePGEtoPGE	($5,936,823)	($6,256,410)	($6,946,711)	($7,312,968)	($7,067,265)	($7,857,488)	($7,180,000)
4500001	Forefeited Discounts	$0	$0	$0	$0	$0	$0	$0
4510001	Miscellaneous Service Revenues	($1,852,377)	($1,830,779)	($1,193,165)	($1,918,764)	($917,276)	($605,804)	($2,096,529)
4540001	Rent From Electric Property	($1,025,319)	($1,206,299)	($1,714,801)	($1,271,846)	($1,453,820)	($1,464,786)	($1,204,074)
4540002	RentFrElecProperty-Joint Pole	($7,679,162)	($6,444,068)	($7,374,023)	($10,582,480)	($12,375,540)	($11,552,214)	($13,294,368)
4560001	Other Electric Revenues	($3,648,451)	($3,825,497)	($3,783,134)	($2,460,519)	($1,686,370)	($2,897,520)	($1,421,421)
4560002	OthElecRev-RegulatoryDeferRev	$0	$0	$0	$0	$0	$0	$0
4560003	OthElecRev-FishWildlifeRecrOps	($12,386)	($11,234)	($12,311)	($13,829)	($16,397)	($18,494)	($12,757)
4560012	OthElecRev-Steam Sales	($1,480,085)	($1,892,218)	($2,160,358)	($1,874,091)	($1,419,239)	($2,128,844)	($1,915,238)
4561001	TransRevOthers-Non-Intertie	($2,899,444)	($3,557,592)	($3,518,555)	($3,412,285)	($3,659,943)	($3,644,320)	($3,531,415)
4561002	TransRevOthers-Intertie	($5,080,702)	($4,953,843)	($7,042,193)	($7,026,637)	($6,945,362)	($6,892,364)	($6,672,000)
5660002	TransOp-MiscExp-IntertieWhePGE	$5,936,823	$6,256,410	$6,946,711	$7,312,968	$7,067,265	$7,857,488	$7,180,000
		($23,677,925)	($23,721,530)	($26,798,541)	($28,560,451)	($28,473,947)	($29,204,345)	($30,147,801)

* Annualized from January-July actuals

PGE

Identified Restoration Events in UE 215 Work Papers

Date	Description
1979	Ice Storm
1980	Ice Storm
1981	Wind Storm, Mid-November
1983	Ice Storm
1987	Wind Storm, December 8-16
1989	Artic Blow, February 1-7
1990	Wind Storm, January 8
1995	Wind Storm, December 12
1996	Ice
1998	Snow & Ice
2000	Wind Storm, January 16
2004	Ice Storm
2006	Wind Storm, December 15-16
2008	Snow & Ice

Winter events

PGE Level III Events, 2010-2021, Excluding 2020 Labor Day Wildfire Emergency

Month	Year	Date Range	Cost	Risk Type	
Oct	2014	10/25/2014-10/28/2014	$ 1,336,678	Non-asset	Weather
Nov	2014	11/11/2014-11/14/2014	$ 2,138,160	Non-asset	Weather
Dec	2014	12/11/2014-12/13/2014	$ 2,149,037	Non-asset	Weather
Mar	2015	3/15/2015-3/16/2015	$ 895,420	Non-asset	Weather
Aug	2015	8/29/2015	$ 851,001	Non-asset	Weather
Nov	2015	11/14/2015	$ 1,315,644	Non-asset	Weather
Dec	2015	12/8/2015	$ 839,050	Non-asset	Weather
Dec	2015	12/21/2015	$ 1,140,474	Non-asset	Weather
Oct	2016	10/13/2016 - 10/16/2016	$ 2,032,016	Non-asset	Weather
Dec	2016	12/08/2016 - 12/11/2016	$ 2,607,790	Non-asset	Weather
Jan	2017	01/04/2017 - 01/05/2017	$ 518,486	Non-asset	Weather
Jan	2017	01/10/2017 - 01/13/2017	$ 4,642,450	Non-asset	Weather
Apr	2017	04/07/2017 - 04/09/2017	$ 5,547,758	Non-asset	Weather
Oct	2017	10/21/2017 - 10/23/2017	$ 614,704	Non-asset	Weather
JAN	2019	01/05/2019 - 01/07/2019	$ 1,214,032	Non-asset	Weather
JUN	2019	06/26/2019 - 06/27/2019	$ 528,367	Non-asset	Weather
JAN	2021	1/12/2021-1/17/2021	$ 3,594,072	Non-asset	Weather
FEB	2021	02/11/2021-02/19/2021	$ 67,906,093	Non-asset	Weather

Winter events

Summary of Costs Attributable to Level III Events
1996-2021

Year (a)	Level III Costs (b)	Inflation (c)	$2021 Costs (d)
1996	5,880,000	2.95%	9,896,388
1997	-	2.29%	-
1998	2,438,440	1.56%	3,950,452
1999	-	2.21%	-
2000	-	3.36%	-
2001	-	2.85%	-
2002	-	1.58%	-
2003	-	2.28%	-
2004	2,976,869	2.66%	4,161,502
2005	-	3.37%	-
2006	3,869,486	3.22%	5,069,837
2007	886,621	2.87%	1,129,243
2008	5,936,058	3.81%	7,282,623
2009	2,106,514	-0.32%	2,592,672
2010	-	1.64%	-
2011	-	3.14%	-
2012	-	2.07%	-
2013	-	1.47%	-
2014	5,623,875	1.62%	6,274,099
2015	5,161,601	0.12%	5,751,410
2016	4,504,081	1.26%	4,956,282
2017	11,351,424	2.14%	12,229,557
2018	-	2.44%	-
2019	1,772,198	1.81%	1,830,656
2020	-	1.00%	-
2021	3,594,072	2.28%	3,594,072
Totals	**56,101,239**		**68,718,793**
Last 8 years as % of total	57%		50%

October 19, 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 206
Dated October 5, 2021

Request:

Reference PGE's response to Staff Data Request 560, Attachment B: Please provide workpapers detailing the calculation of depreciation expenses by FERC account included in the $55,920,000 Colstrip Units 3 & 4 revenue requirement in the reference attachment.

Response:

Attachment 206-A provides the requested information.

AWEC DR 206 - Colstrip Depreciation Expense in Revenue Requirements

FERC Acct	Depreciation Expense
311	$ 3,044,835
312	$ 13,591,218
312- Decom Accrual	$ 1,963,552
314	$ 4,006,113
315	$ 852,827
316	$ 255,242
Total	**$ 23,713,787**

Colstrip (Steam)

Net Salvage -3%

Row Labels	Sum of end_balance	Sum of total_reserve
31101-COLSTRIP - PGE SHARE (20%)	91,313,879	78,568,984
31102-COLSTRIP -PGE SHARE (20%)	907,782	115,219
31105-COLSTRIP - PGE SHARE (20%)	28,838,244	28,753,434
31200-COLSTRIP - PGE SHARE (20%)	207,486,999	136,639,790
31205-COLSTRIP - PGE SHARE (20%)	71,697,784	73,903,634
31400-COLSTRIP - PGE SHARE (20%)	76,409,473	56,000,449
31500-COLSTRIP - PGE SHARE (20%)	25,684,337	21,622,181
31601-COLSTRIP - PGE SHARE (20%)	6,993,550	5,756,987
Grand Total	**509,332,046.72**	**401,360,678.93**

Depreciation Base

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
31101-COLSTRIP - PGE SHARE (20%)	15,484,311	15,256,601	15,028,890	14,801,180	14,573,469	14,345,759	14,118,048	13,890,338	13,662,628	13,434,917	13,207,207	12,979,496
31102-COLSTRIP -PGE SHARE (20%)	819,796	807,740	795,684	783,628	771,572	759,517	747,461	735,405	723,349	711,293	699,238	687,182
31105-COLSTRIP - PGE SHARE (20%)	949,958	935,988	922,018	908,048	894,078	880,108	866,138	852,168	838,198	824,228	810,258	796,288
31200-COLSTRIP - PGE SHARE (20%)	77,071,819	75,938,410	74,805,001	73,671,592	72,538,183	71,404,774	70,271,364	69,137,955	68,004,546	66,871,137	65,737,728	64,604,319
31205-COLSTRIP - PGE SHARE (20%)	(54,917)	(54,110)	(53,302)	(52,494)	(51,687)	(50,879)	(50,072)	(49,264)	(48,456)	(47,649)	(46,841)	(46,034)
31400-COLSTRIP - PGE SHARE (20%)	22,701,307	22,367,465	22,033,622	21,699,779	21,365,936	21,032,094	20,698,251	20,364,408	20,030,565	19,696,723	19,362,880	19,029,037
31500-COLSTRIP - PGE SHARE (20%)	4,832,686	4,761,618	4,690,549	4,619,480	4,548,411	4,477,342	4,406,273	4,335,204	4,264,135	4,193,066	4,121,997	4,050,928
31601-COLSTRIP - PGE SHARE (20%)	1,446,369	1,425,099	1,403,829	1,382,559	1,361,289	1,340,018	1,318,748	1,297,478	1,276,208	1,254,938	1,233,668	1,212,398

Ending Reserve

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
31101-COLSTRIP - PGE SHARE (20%)	78,796,695	79,024,405	79,252,116	79,479,826	79,707,536	79,935,247	80,162,957	80,390,668	80,618,378	80,846,089	81,073,799	81,301,510
31102-COLSTRIP -PGE SHARE (20%)	127,275	139,331	151,387	163,443	175,498	187,554	199,610	211,666	223,722	235,777	247,833	259,889
31105-COLSTRIP - PGE SHARE (20%)	28,767,404	28,781,374	28,795,343	28,809,313	28,823,283	28,837,253	28,851,223	28,865,193	28,879,163	28,893,133	28,907,103	28,921,073
31200-COLSTRIP - PGE SHARE (20%)	137,773,199	138,906,608	140,040,018	141,173,427	142,306,836	143,440,245	144,573,654	145,707,063	146,840,472	147,973,881	149,107,290	150,240,700
31205-COLSTRIP - PGE SHARE (20%)	73,902,827	73,902,019	73,901,211	73,900,404	73,899,596	73,898,789	73,897,981	73,897,173	73,896,366	73,895,558	73,894,751	73,893,943
31400-COLSTRIP - PGE SHARE (20%)	56,334,292	56,668,135	57,001,978	57,335,820	57,669,663	58,003,506	58,337,349	58,671,191	59,005,034	59,338,877	59,672,720	60,006,562
31500-COLSTRIP - PGE SHARE (20%)	21,693,250	21,764,318	21,835,387	21,906,456	21,977,525	22,048,594	22,119,663	22,190,732	22,261,801	22,332,870	22,403,939	22,475,008
31601-COLSTRIP - PGE SHARE (20%)	5,778,258	5,799,528	5,820,798	5,842,068	5,863,338	5,884,608	5,905,878	5,927,149	5,948,419	5,969,689	5,990,959	6,012,229

Depreciation Expense

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total		
31101-COLSTRIP - PGE SHARE (20%)	227,710	227,710	227,710	227,710	227,710	227,710	227,710	227,710	227,710	227,710	227,710	227,710	**2,732,526**		
31102-COLSTRIP -PGE SHARE (20%)	12,056	12,056	12,056	12,056	12,056	12,056	12,056	12,056	12,056	12,056	12,056	12,056	**144,670**		
31105-COLSTRIP - PGE SHARE (20%)	13,970	13,970	13,970	13,970	13,970	13,970	13,970	13,970	13,970	13,970	13,970	13,970	**167,640**		
31200-COLSTRIP - PGE SHARE (20%)	1,133,409	1,133,409	1,133,409	1,133,409	1,133,409	1,133,409	1,133,409	1,133,409	1,133,409	1,133,409	1,133,409	1,133,409	**13,600,909**		
31205-COLSTRIP - PGE SHARE (20%)	(808)	(808)	(808)	(808)	(808)	(808)	(808)	(808)	(808)	(808)	(808)	(808)	**(9,691)**		
31400-COLSTRIP - PGE SHARE (20%)	333,843	333,843	333,843	333,843	333,843	333,843	333,843	333,843	333,843	333,843	333,843	333,843	**4,006,113**		
31500-COLSTRIP - PGE SHARE (20%)	71,069	71,069	71,069	71,069	71,069	71,069	71,069	71,069	71,069	71,069	71,069	71,069	**852,827**		
31601-COLSTRIP - PGE SHARE (20%)	21,270	21,270	21,270	21,270	21,270	21,270	21,270	21,270	21,270	21,270	21,270	21,270	**255,242**		
													21,750,235	1,963,552	**23,713,787**
														Annual Decom Accrual	

Depreciation Rate

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
Months Remaining	68	67	66	65	64	63	62	61	60	59	58	57
31101-COLSTRIP - PGE SHARE (20%)	17.65%	17.91%	18.18%	18.46%	18.75%	19.05%	19.35%	19.67%	20.00%	20.34%	20.69%	21.05%
31102-COLSTRIP -PGE SHARE (20%)	17.65%	17.91%	18.18%	18.46%	18.75%	19.05%	19.35%	19.67%	20.00%	20.34%	20.69%	21.05%
31105-COLSTRIP - PGE SHARE (20%)	17.65%	17.91%	18.18%	18.46%	18.75%	19.05%	19.35%	19.67%	20.00%	20.34%	20.69%	21.05%
31200-COLSTRIP - PGE SHARE (20%)	17.65%	17.91%	18.18%	18.46%	18.75%	19.05%	19.35%	19.67%	20.00%	20.34%	20.69%	21.05%
31205-COLSTRIP - PGE SHARE (20%)	17.65%	17.91%	18.18%	18.46%	18.75%	19.05%	19.35%	19.67%	20.00%	20.34%	20.69%	21.05%
31400-COLSTRIP - PGE SHARE (20%)	17.65%	17.91%	18.18%	18.46%	18.75%	19.05%	19.35%	19.67%	20.00%	20.34%	20.69%	21.05%
31500-COLSTRIP - PGE SHARE (20%)	17.65%	17.91%	18.18%	18.46%	18.75%	19.05%	19.35%	19.67%	20.00%	20.34%	20.69%	21.05%
31601-COLSTRIP - PGE SHARE (20%)	17.65%	17.91%	18.18%	18.46%	18.75%	19.05%	19.35%	19.67%	20.00%	20.34%	20.69%	21.05%

October 19, 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 208
Dated October 5, 2021

Request:

Please detail the monthly roll forward of Colstrip Units 3 & 4 rate base to May 1, 2022, starting with the December 31, 2020 actual balances. Please detail all incremental accumulated depreciation, deferred taxes, capital additions, and any other incremental or decremental plant balances necessary to derive the May 2022 amounts included in revenue requirement.

Response:

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:

Attachment 208-A provides Colstrip monthly activity for plant and reserve balances. Attachment 208-A also provides deferred tax balances for 12/31/2020, 12/31/2021, and 4/30/2022.

Colstrip Monthly Activity - 12/31/2021 through 4/30/2022

Gross Plant	**Beg Balance**	**202101**	**202102**	**202103**	**202104**	**202105**	**202106**	**202107**	**202108**	**202109**	**202110**	**202111**	**202112**	**202201**	**202202**	**202203**	**202204**	**Ending Balance**
Additions	$ 529,768,952	5,264,485	602,895	5,226	1,987,046	4,487,687	3,087,879	663,532	500,641	100,638	182,754	100,638	2,805,351	373	373	373	373	
ARO	$ (34,911,263)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Monthly Activity	$ -	5,264,485	602,895	5,226	1,987,046	4,487,687	3,087,879	663,532	500,641	100,638	182,754	100,638	2,805,351	373	373	373	373	
Cumulative Total	**$ 494,857,688**	**$ 500,122,173**	**$ 500,725,068**	**$ 500,730,294**	**$ 502,717,340**	**$ 507,205,027**	**$ 510,292,906**	**$ 510,956,439**	**$ 511,457,080**	**$ 511,557,719**	**$ 511,740,472**	**$ 511,841,111**	**$ 514,646,462**	**$ 514,646,835**	**$ 514,647,208**	**$ 514,647,582**	**$ 514,647,955**	**$ 514,647,955**

Accumulated Reserve	**Beg Balance**	**202101**	**202102**	**202103**	**202104**	**202105**	**202106**	**202107**	**202108**	**202109**	**202110**	**202111**	**202112**	**202201**	**202202**	**202203**	**202204**	**Ending Balance**
Depreciation Expense	$ (390,683,297)	(1,256,111)	(1,341,487)	(1,346,801)	(1,124,068)	(1,976,149)	(1,976,149)	(1,976,149)	(1,976,149)	(1,976,149)	(1,976,149)	(1,976,149)	(1,976,149)	(1,976,149)	(1,976,149)	(1,976,149)	(1,976,148)	
ARO	$ 35,787,704	280,596	221,499	221,499	221,499	221,499	221,499	221,499	221,499	221,499	221,499	221,499	221,499	221,499	221,499	221,499	221,499	
Monthly Activity	$ -	(975,515)	(1,119,988)	(1,125,302)	(902,569)	(1,754,650)	(1,754,650)	(1,754,650)	(1,754,650)	(1,754,650)	(1,754,650)	(1,754,650)	(1,754,650)	(1,754,650)	(1,754,650)	(1,754,650)	(1,754,649)	
Cumulative Total	**$ (354,895,592)**	**$ (355,871,107)**	**$ (356,991,095)**	**$ (358,116,397)**	**$ (359,018,966)**	**$ (360,773,617)**	**$ (362,528,267)**	**$ (364,282,917)**	**$ (366,037,567)**	**$ (367,792,218)**	**$ (369,546,868)**	**$ (371,301,518)**	**$ (373,056,168)**	**$ (374,810,818)**	**$ (376,565,468)**	**$ (378,320,118)**	**$ (380,074,767)**	**$ (380,074,767)**
Colstrip Plant Rate Base	**$ 139,962,096**	**$ 144,251,066**	**$ 143,733,974**	**$ 142,613,897**	**$ 143,698,374**	**$ 146,431,411**	**$ 147,764,640**	**$ 146,673,522**	**$ 145,419,513**	**$ 143,765,501**	**$ 142,193,604**	**$ 140,539,593**	**$ 141,590,294**	**$ 139,836,017**	**$ 138,081,740**	**$ 136,327,463**	**$ 134,573,188**	**$ 134,573,187**

	12/31/2020 Balance		
Accumulated Deferred Income Taxes[1]	(14,052,964)	(11,604,401)	(6,904,916)
Excess Accumulated Deferred Income Taxes	(4,910,910)	(4,074,166)	(3,213,808)

1. The ADIT balances above are inclusive of the Excess ADIT amounts referenced in line 20.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Compensation

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Anne Mersereau
Tamara Neitzke

December 2, 2021

Table of Contents

I. Introduction

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

A. My name is Anne Mersereau. My position is Vice President, Human Resources, Diversity and Inclusion.

My name is Tamara Neitzke. My position is Director of Total Rewards in the Human Resources Department.

Our qualifications appear at the end of PGE Exhibit 300.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is two-fold: (1) we provide additional support for PGE's total compensation costs for the 2022 test year; and (2) we respond to the positions and proposals by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), Alliance of Western Energy Consumers (AWEC), and the Oregon Citizens Utility Board (CUB), (collectively, the Parties) regarding three areas: total labor requirements, incentives, and other benefits. In particular, we show that:

- Staff's and AWEC's proposed adjustments to PGE's total labor budget are unreasonable and would not allow PGE to compete successfully for qualified candidates, inhibit our ability to retain talent, and impact our ability to adequately support our labor requirements with overtime and contract labor. Furthermore, reducing PGE's labor request to levels proposed by Staff and AWEC will jeopardize PGE's system resiliency and reliability, cyber and physical security, safety, and overall effectiveness, ultimately increasing future costs. PGE's 2022 forecast of total labor requirements is *below* our last three years of actuals (i.e., 2018-2020 actuals) and based on historical and future needs and objective market-based criteria such as market surveys, Bureau of Labor statistics, and Oregon Office of Economic Analysis data. Additionally, Parties ignore PGE's efforts and commitment to keeping labor increases below the current and expected rate of inflation for 2021 and 2022.

- The amount of incentive pay in PGE's test year is reasonable and is an important component of an employee's total compensation.
- Staff's and CUB's proposed adjustments to several of PGE's other benefits are unreasonable due to incorrect assumptions in their analysis.

Q. How is the remainder of your testimony organized?

A. After this introduction, our testimony has three additional sections:

- In Section II, we rebut Staff's and AWEC's proposals to reduce PGE's total labor request. We show that PGE's method for forecasting total labor and our projected total labor needs is based on sound methods resulting in a reasonable request in this case.
- In Section III, we discuss a correction to the presentation of PGE's incentives, rebut Staff's proposed adjustments to PGE's incentive pay, and discuss how PGE's test year cost for incentive pay is fair and reasonable.
- In Section IV, we address Staff's proposal to increase PGE's FAS 87 pension expense expected long-term rate of return (EROA) by 40 basis points and discuss the issues with their proposal. Additionally, we rebut CUB's proposed adjustment to PGE's mass transit benefit.

II. Total Labor Requirements

Q. Please summarize Parties' proposals regarding PGE's total labor costs.

A. Staff proposes to escalate PGE's wages and salaries using Staff's three-year wages and salaries model. Starting with PGE's 2019 straight-time wages and salaries, Staff escalates non-union wages to the 2022 test year using the All-Urban Consumer Price Index (CPI). For union wages, Staff uses contracted wage escalation rates for 2020 through 2022. Staff then uses a sharing mechanism to split the difference in projected wages and salaries 50/50 between PGE's forecast and Staff's estimated amount. From this model, used for both straight time and overtime costs, Staff calculates an approximate $12 thousand reduction to PGE's labor forecast. Staff then uses their model to calculate an average employee salary for each employee classification and using this proposes to reduce PGE's total labor by an additional $9.2 million based on using a June 30, 2021 head count number provided by PGE as a proxy for PGE's labor requirements.

AWEC argues that basing PGE's 2022 labor on 2020 budgets has little bearing on the costs expected in 2022 and therefore proposes that all labor escalation from 2020 to 2022 be removed from PGE's request.

Q. Please describe PGE's concerns regarding Staff's wage and salaries model.

A. According to Staff testimony, the results of their model produce a modest reduction of approximately $12 thousand to Officer wages and salaries. However, when reviewing the model provided as Staff Exhibit 304, it becomes evident their model produces a forecasted wage and salary <u>increase</u> to straight-time labor of approximately $12.1 million and an <u>increase</u> to overtime labor of $13.0 million. This result, however, is obscured by a calculation design in Staff's model that replaces any positive variance with a zero-dollar amount. PGE Exhibit 1501 provides the results of Staff's unconstrained 3-Year Wage and Overtime Formula.

Q. What does this unconstrained model result indicate regarding PGE's wages and salaries request?

A. This clearly indicates that PGE's labor request in this case, as we highlighted in PGE Exhibit 300, is very modest and well below the current inflationary expectations for 2021 and 2022. By simply taking the unconstrained result of Staff's model, PGE should have requested an additional $12 million in straight-time labor costs and an additional $13 million in overtime. Table 1 below provides the difference between PGE's wages and salaries request and Staff's unconstrained model result as provided in Staff Exhibit 304.

Table 1
Staff 3-Year Model Result

		Officer	Exempt	Non-Exempt	Union	Total
a	**Staff 2022 Straight-Time**	4,434	227,384	28,299	75,778	335,895
b	**PGE 2022 Straight-Time**	4,458	217,403	27,565	74,390	323,816
c	**Difference (a-b)**	(24)	9,981	734	1,388	12,079
d	**Staff 2022 Overtime**			1,733	30,648	32,381
e	**PGE 2022 Overtime**			1,293	18,051	19,344
f	**Difference (d-e)**			440	12,597	13,037
g	**Total (c+f)**	**(24)**	**9,981**	**1,174**	**13,985**	**25,116**

Q. Does PGE consider its labor costs in the simple terms of full-time equivalent employees (FTE) or headcount?

A. No. This type of view does not reflect the realities of the current labor market nor does it reflect the types of labor PGE utilizes to meet the needs of the business. As we stated in Exhibit 300, to 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 (straight-time and overtime) and contract labor.

Q. From what perspective does Staff analyze PGE's labor requirements?

A. Staff focuses primarily on straight-time FTE and head count numbers provided by PGE in response to data requests, which does not accurately represent PGE's past or future total labor requirements.

Q. Does Staff discuss PGE's contract labor in their testimony?

A. Yes. While they neglect to include PGE's contract labor into any meaningful analysis of PGE's labor requirements, Staff appears to suggest that PGE's forecast of contract labor is too low. Staff notes that PGE's contract labor actuals have consistently been over $40 million, while PGE's test year forecast is only $15 million. While PGE is not clear as to the point Staff is trying to make, their analysis suggests that, at $25 million below 2020 amounts, PGE's 2022 test year contract labor forecast is under-forecasted. Yet, at the same time, Staff argues PGE's forecasted labor requirements are "excessive,"[1] proposing a reduction of approximately $9.2 million from PGE's labor forecast. It becomes clear, when viewing PGE's total labor, including overtime and contractors, that Staff's claim of "excessive" labor is without merit and without support.

Q. How does PGE's 2022 total labor forecast compare with recent actuals?

A. PGE's overall labor request for 2022 is $10.8 million below 2020 actuals and $23.6 million below 2019 actuals. In fact, as Table 2 and Table 3 below demonstrate, PGE's total labor requirements for 2022 are below PGE's prior three years of actuals.

Table 2
Aggregate Total Labor

(in millions)	2018 Actuals	2019 Actuals	2020 Actuals	2022 Test Year	2018-2022	2019-2022	2020-2022
Balance Sheet	117.6	144.2	147.4	122.7	5.0	(21.5)	(24.7)
Income Statement	240.4	231.0	215.1	229.0	(11.4)	(2.0)	13.9
Total	**358.0**	**375.3**	**362.5**	**351.7**	**(6.3)**	**(23.6)**	**(10.8)**

[1] Staff/300/page 18/line 3.

Table 3
Straight-Time, Overtime, & Contract Aggregate Labor

(in millions)	2018 Actuals	2019 Actuals	2020 Actuals	2022 Test Year	2018-2022	2019-2022	2020-2022
Straight-Time	269.3	287.2	293.2	317.3	48.0	30.1	24.1
Overtime	28.2	31.0	27.4	19.3	(8.9)	(11.7)	(8.0)
Contract	60.5	57.1	41.9	15.0	(45.4)	(42.0)	(26.9)
Total	**358.0**	**375.3**	**362.5**	**351.7**	**(6.3)**	**(23.6)**	**(10.8)**

Q. Please describe PGE's concerns with using a headcount number to set PGE's labor requirements.

A. There are a couple issues with using headcount as a proxy for PGE's test year labor requirements. First, headcount is a point in time number. A headcount number constantly changes depending on the point in time it is measured. There are likely as many different headcount numbers in a year as there are business days in a year. In contrast, PGE's 2022 test year forecast of labor requirements (and the comparison to historical actuals) reflects labor costs over time, for use in an annualized (i.e., 12 month) revenue requirement. As such, headcount is not appropriate to use for determining annualized labor requirements. Second, irrespective of whether a point in time measurement for use in an annualized forecast is appropriate, strictly looking at headcount (or straight-time FTE) does not accurately reflect PGE's actual, nor PGE's forecast total labor requirements, as both overtime and contract labor are excluded.

Q. Are PGE's 2022 FTE forecasted to increase compared with 2020 actuals?

A. Yes. Which is what Staff based most of their labor adjustment upon. However, this narrow view of PGE's labor force ignores two primary elements of PGE's total labor requirements (i.e., overtime and contract labor), when viewed holistically, show PGE is, in fact, forecasting a decrease to its total labor compared to 2020 actuals. As we discuss in PGE Exhibit 300, looking at FTEs in isolation tends to mask overall changes to PGE's labor needs, as neither contractor hours nor overtime hours are factored in. Whether performed by PGE straight time FTEs, by overtime, or by contract labor, the work, which is critical to providing safe, reliable, secure, and affordable energy to customers must get done. As such, PGE, similar to other large employers, must often times supplement its workforce with contract labor or more overtime hours in lieu of straight-time labor when there are changes in the work being performed, or when it becomes difficult to fill critical positions with qualified employees.

Q. Does PGE have any other concerns with focusing on FTEs and headcount to determine PGE's total labor requirements?

A. Yes. Another issue with focusing solely on PGE's straight-time labor, as reflected through FTEs or headcount, is that it ignores the critical shortage of skilled labor available in the current labor market and PGE's response to this reality. In fact, the skilled labor market has been tight for a number of years with more than half of all job vacancies in Oregon being difficult to fill even back in 2018 and 2019.[2] This situation has only become more acute in 2020 and 2021, with nearly half of all respondents to a recent National Association of Business Economics (NABE) survey reporting a shortage of skilled workers in the third quarter of 2021.[3] PGE's experience is consistent with these trends, which is a key reason why both overtime and contract labor must be viewed alongside with and not separate from straight-time labor (i.e., FTE or headcount). Consistent with general economic trends, PGE's turnover has also increased over this time, creating additional strains on PGE's ability to maintain a fully staffed internal labor force. Figure 1 below provides PGE's quarterly turnover rate since 2017, which has effectively doubled.

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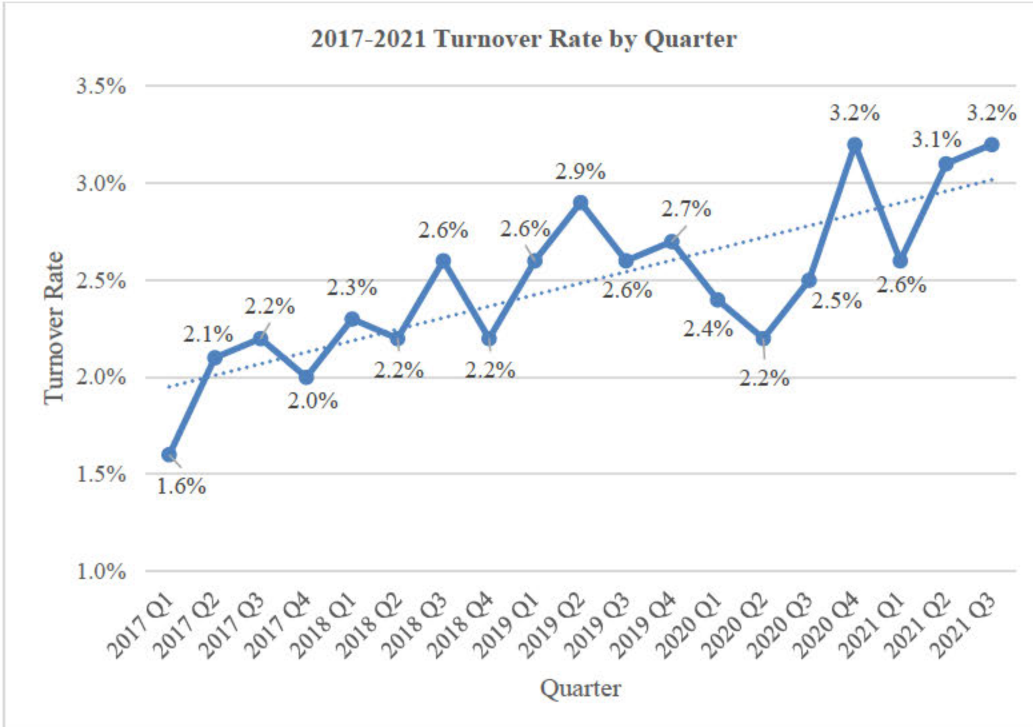
[2] See page 4 of the September OEA Oregon Economic and Revenue Forecast, provided here as PGE Exhibit 1503.
[3] https://www.cnn.com/2021/10/25/economy/business-conditions-worker-shortage/index.html.

Figure 1



However, whether or when a position is filled does not determine if or when the work must be accomplished. PGE serves a critical function, and our customers depend on our ability to deliver on our promise of safe, reliable, secure, and affordable energy. As such, the use of overtime and contract labor is not only a strategic choice, but also often a necessary reality.

Q. Staff argues that PGE has historically budgeted more FTEs than necessary as support for their FTE adjustment.[4] How does PGE respond to this argument?

A. Staff points to 2017 and 2018 FTE numbers as support for their argument, while once again failing to account for PGE's other labor costs (i.e., overtime and contract labor) over the same period. However, if you look at PGE's total labor over the same period, it becomes clear that PGE in fact under budgeted its total labor costs in both 2017 and 2018. Table 4 below provides

[4] Staff Exhibit 300, page 16.

straight-time, overtime, and contract labor dollars for PGE's 2017 and 2018 budgets, plus PGE's filed test year request for 2019 docketed as UE 335. In every year, PGE's actual costs exceeded amounts budgeted or forecast.

Table 4
2017-2019 Budget/Forecast to Actual Total Labor

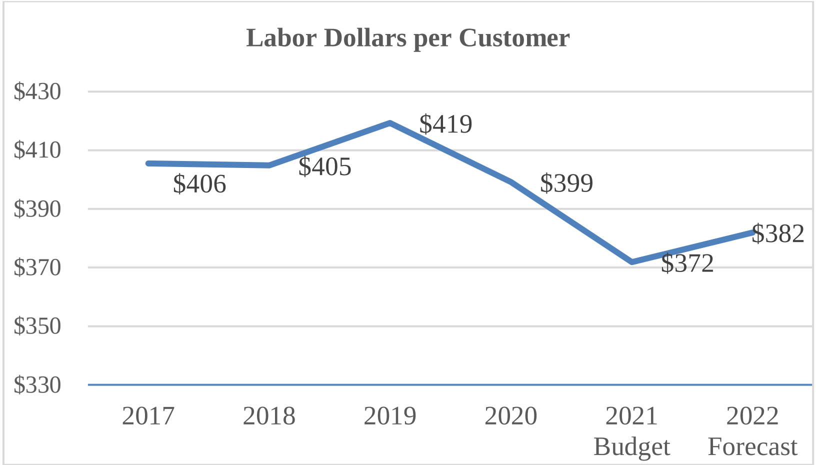
(in Millions)	**2017 Budget**	**2017 Actuals**	**2017 Delta**	**2018 Budget**	**2018 Actuals**	**2018 Delta**	**2019 GRC Filed**	**2019 Actuals**	**2019 Delta**
Straight-Time	259.8	261.0	1.2	274.8	269.3	(5.5)	283.3	287.2	3.8
Overtime	19.6	30.3	10.8	20.5	28.2	7.7	21.1	31.0	10.0
Contractor	41.7	63.3	21.6	45.0	60.5	15.4	54.5	57.1	2.5
Total	**321.1**	**354.6**	**33.6**	**340.4**	**358.0**	**17.6**	**359.0**	**375.3**	**16.3**

Q. How do you respond to Staff providing customers per FTE to demonstrate PGE's increase in labor spending?

A. Similar to the other metrics presented by Staff in their argument, we believe these figures[5] are not useful as they only reflect part of the picture. Again, when viewed holistically, the numbers tell a different story. As demonstrated in Figure 2 below, when calculating PGE's total labor dollars per customer, labor costs on a per customer basis have actually gone down since 2017. In other words, contrary to what Staff presents, PGE is more efficient on a per customer basis.

[5] Staff Exhibit 300, Figure 11.

Figure 2



Q. Please summarize your response to Staff's proposed adjustments to PGE's total labor requirements.

A. A simple review of Staff's 3-year wage and salaries model, which calculates an amount $25 million above PGE's forecast for labor, indicates that PGE's test year labor request is reasonable. Additionally, Staff's focus on straight-time labor through their review of FTEs and headcount fails to take into account two of PGE's three primary labor components and the fact that PGE, like many other businesses, has an obligation to its customers. Whether through straight-time, overtime, or contract labor, PGE must meet our customer's needs for safe, reliable, secure, and affordable energy.

Q. What is the basis for AWEC's adjustment to PGE's labor forecast?

A. AWEC argues that PGE "has provided zero analytical support"[6] for its labor costs, basing their claim on PGE's response to AWEC Data Request Nos. 036 and 121, where we explain PGE does not have a wage and labor model.

Q. How does PGE respond to AWEC's argument and basis for their adjustment?

[6] AWEC Exhibit 100, page 23, line 5.

A. Similar to their argument for PGE's non-labor O&M costs, which we respond to in PGE Exhibit 1600, AWEC's argument ignores the substance and support for PGE's request. PGE filed its case with discussions of labor and non-labor costs in direct testimony Exhibits 200 (Revenue Requirements), 300, 400, 500 (Customer Service), 700 (Production), 800 (T&D) and all corresponding exhibits and work papers, comparing PGE's 2022 forecasted labor and non-labor O&M expenses to 2020 <u>actual</u> expenses. In other words, our initial request in this case included hundreds of pages of testimony and analytical support for PGE's 2022 labor and non-labor forecast. The fact that AWEC responds to none of PGE's testimony and data in support of our test year request, instead choosing to base their adjustment on a few high-level data responses points to a lack of effort in analyzing the facts of PGE's request.

Q. Does AWEC support their adjustment with any factual information or analytical support of their own?

A. No. AWEC provides no evidence or indication they reviewed the work papers, exhibits, and testimony in support of PGE's labor and non-labor test year request, and they perform no analysis or discovery on the substance of PGE's test year request to support the basis of their adjustment.

Q. Does any other party testimony provide analysis supporting PGE's labor escalation?

A. Yes. As we highlighted above, in contrast to AWEC's brief unsupported proposal to adjust PGE's total labor, OPUC Staff utilize a wage and salary model with actual PGE-provided straight-time and overtime wages, which demonstrates that PGE's 2022 forecast is very modest and likely below market. Additionally, as Staff Exhibit 300 points out, PGE's forecast for contract labor is well below recent historical actuals.

Q. Does PGE simply escalate budget data to develop its 2021 budget and 2022 test year labor costs?

A. No. PGE provides an overview of its O&M budgeting process in PGE Exhibit 1600 and an overview of its capital budgeting process in PGE Exhibit 1800. In both pieces of testimony, PGE describes a consistent process that is robust, well defined, and involves numerous layers of evaluation and approvals. For labor specifically, PGE begins with currently filled and unfilled approved positions that include current salary information of existing employees and well-defined market rates for open positions, which are validated against information provided from PGE's Human Resources department. Departments then compare these baseline hours, along with overtime and contract budget amounts, against the expected on-going base business work expected for their areas and any additional capital and/or O&M projects above existing business requirements. From this departmental review there may be additions or reductions identified before budgets are submitted for Corporate Planning review, Officer review, and finally Board of Director approval. Throughout this process, variances above and below existing labor are reviewed and scrutinized, while individual department entries are consolidated and coordinated into a total company review. The fact is, contrary to AWEC's statements and supported by our extensive documentation, PGE's annual development of labor needs is very robust.

Q. After determining labor requirements, how does PGE account for escalation within its labor requirements?

A. Once all the department budgets are final, escalation is applied to the labor dollars for the budget year, based on rates provided by Human Resources by employee group. These escalation rates, which are discussed in PGE Exhibits 200 and 300, are based on market surveys and Bureau of Labor Statistics Data. AWEC suggests that by its very nature escalating labor costs is somehow imprudent yet provides no clear explanation to support this claim or any alternative for forecasting inflationary pressures.

Q. How do the escalation rates used by PGE for its 2021 budget and 2022 forecast compare to current inflation projections?

A. As we discuss in PGE Exhibit 300, Section III, PGE escalated its non-bargaining straight-time and overtime wages and salaries by only 2.5% for 2021 and 3.0% for 2022 and union wages and salaries by 3.5% for 2021 and 2022. For contract labor, the escalation rate used for 2022 was only 2.88%, based upon February 2021 IHS Markit Global Insights forecast data. For comparison purposes, the most recent Oregon Office of Economic Analysis economic forecast indicates Oregon Average Wage Rate inflation of 5.0% in 2021 and 3.0% in 2022, U.S. Average Wage Rate inflation of 5.2% in 2021 and 3.6% in 2022, and its West Region Urban Consumer Price Index forecasts inflation of 4.5% in 2021 and 3.9% in 2022.[7]

Q. Please summarize your response to AWEC's proposal.

A. Rather than focus on the substance of PGE's case, AWEC proposes an adjustment that lacks any meaningful basis and ignores the facts PGE has presented within numerous pieces of testimony, exhibits, and work papers. AWEC has provided no support for their adjustment. When viewed against Staff's 3-year wage and salaries model and current state economic projections, AWEC's proposal is clearly unreasonable.

Q. What would be the result of applying Staff's or AWEC's proposed adjustments to PGE's labor request?

[7] See page 37 of the December 2021 Oregon Economic and Revenue Forecast, provided here as PGE Exhibit 1504.

A. PGE's wages and salaries for 2022 would be well below the market and PGE would find itself at a competitive disadvantage in hiring and retaining qualified individuals and be less able to support our requirements with overtime and contractors. PGE is faced with stiff competition in the labor market for highly skilled jobs, which makes it both difficult to recruit <u>and</u> difficult to retain qualified employees. If we are unable to escalate our wages and salaries at a level consistent with our competition in the state and are unable to supplement our existing workforce with qualified contract labor, PGE will be faced with higher turnover and increasing difficulties in hiring and maintaining a qualified, skilled workforce, which will lead to increased hiring costs and reduced effectiveness.

III. Incentives

Q. Please summarize Staff's proposed adjustment to PGE's incentive pay.

A. Staff recommends a reduction to PGE's test year non-officer incentives of $6.6 million, allocating $4.2 million to an O&M reduction and $2.4 million to a capital cost reduction. Additionally, though it appears it did not make it into Staff's adjustment amounts included in Staff Exhibit 304, tab "PUC Misc. Labor" or into Staff's revenue requirement model, Staff proposes to reduce PGE's officer incentives by $439 thousand, even though PGE did not include a request for any Officer incentives in this case.

Q. What is the basis for Staff's proposal?

A. Staff calculates a 2018-2020 average of actual non-officer incentives, reduces this amount by 50% then proposes to reduce PGE's 2022 forecast by the difference between their calculated average and PGE's non-officer incentive request. For officer incentives, Staff again uses a three-year average of actuals to determine a 100% average amount and indicates that because their calculated amount is greater than the officer incentive amount PGE removed from its initial request, an additional adjustment is warranted.

Q. Can you please restate PGE's filed incentives request.

A. While PGE presented its incentive request in PGE Exhibit 300 as totaling approximately $18.6 million, the actual amount of incentives forecast within PGE's filing totaled $13.7 million. This discrepancy is due to a change in accounting for allocations beginning in 2021.[8] While the new allocation account was included within PGE's revenue requirement, it was inadvertently excluded from PGE's presentation of incentives resulting in the appearance of

[8] PGE's incentive allocation credit was moved from account 9200017 to 9220003 beginning in 2021.

an incentives forecast greater than amounts included in PGE's test year request. Table 5 below summarizes PGE's actual incentive costs for 2020 and our request for 2022 including the allocation credit amount that was included in PGE's filed revenue requirement.

Table 5
Total Incentives ($000)

Incentive Plans	**2020 Actuals**	**2022 Test Year(1)**
Performance Incentive Compensation	$8,567	$4,960
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	$13,684

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

Q. Is Staff's proposal reasonable when compared to PGE's corrected incentive forecast?

A. No. Properly reflecting the allocation credit amount produces an incentive forecast that is very much in line with the amount forecast by Staff in their analysis. While Staff's three-year average produces a total incentive amount of $11.9 million, they neglect to account for inflation of 2018-2020 amounts into 2022 dollars. When accounting for this omission, Staff's forecast is very similar to the amount PGE included in its revenue requirement.

Q. How does PGE's incentive request compare with Staff's 3-year model?

A. When using Staff's three-year model to test the reasonableness of PGE's incentive request, Staff's model produces a forecasted amount that is greater than amounts PGE is requesting in this case. While PGE does not necessarily agree with the methodology of Staff's 3-year model, its results provide additional support as to the reasonableness of PGE's incentive request for the 2022 test year.[9]

[9] PGE Exhibit 1502 provides the results of this model.

Q. What is Staff's reasoning for adjusting Officer incentives?

A. Staff argues that while PGE removed Officer incentives from the 2022 test year, they found that the Officer incentive forecast was understated.[10] Therefore, because Staff calculates a historical average amount of Officer incentives greater than PGE's 2022 forecast, which was removed in total from the 2022 test year, they propose an additional adjustment of $439 thousand to account for the difference. Staff reasons that it is "more appropriate to rely on an average of Officer incentives paid in 2018-2020 rather (than) PGE's budgeted amount because these amounts are actuals and not forecasts."[11]

Q. Is Staff's reasoning for adjusting PGE's Officer incentives below the total amount forecast in 2022 appropriate?

A. No. PGE's Officer incentives are budgeted and clearly identifiable by account and account work order information. Using this information, PGE voluntarily removed <u>all</u> forecast amounts prior to filing. Staff's reasoning and adjustment lacks a clear basis. In fact, PGE's forecast for Officer incentives has no impact on the incentive amounts requested for recovery in the test year, because PGE is not requesting recovery of any Officer incentives. Regardless of whether PGE based its test year incentive forecast on a three-year average of actuals or upon an expectation of eligible employees, base salaries, and target payout projections based on plan design is irrelevant. PGE's Officer incentive costs are clearly distinguishable in both actuals and forecast and the fact is PGE has not requested recovery of any Officer incentive amounts in this case. Staff's adjustment amounts to setting PGE's test-year Officer incentive forecast to a negative amount.

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[10] Staff/300/page 12.
[11] Staff/300/page 13/lines 2-4.

Q. In summary, what is PGE's position on incentive pay?

A. Incentive pay is part of a competitive total compensation package where high performing employees are rewarded with a larger total annual compensation package based on competitively pre-established performance goals. The incentive goals for all participants stem from PGE's corporate scorecard goals, which support our strategic direction and our commitment to core principles, such as delivering exceptional customer experiences and pursuing excellence in our work. PGE's proposal is consistent with Commission precedent and represents a reasonable sharing of incentive costs between PGE's shareholders and its customers. Particularly when correcting for the presentation of PGE's incentive forecast and aligning it to the amounts PGE included within its integrated revenue requirement request, the adjustments made by Staff are excessive and unreasonable and would affect PGE's ability to attract and retain qualified employees.

IV. Miscellaneous Benefits

Q. Please summarize the Parties position on PGE's benefits.

A. Staff proposes to adjust PGE's pension expense forecast by approximately $2.6 million by estimating the impact of increasing PGE's Expected Long-Term Rate of Return on Assets (EROA) from 7.0% to 7.40%. CUB proposes an adjustment to PGE's mass transit benefit of approximately $71 thousand based on the approximate number of employees moving from PGE's downtown World Trade Center (WTC) location to PGE's new Integrated Operations Center (IOC), located in Tualatin. No other adjustments are proposed by parties regarding PGE's benefits or post-retirement costs as presented in PGE Exhibit 300.

Q. What is the basis of Staff's proposed pension adjustment.

A. While Staff recognizes that PGE's EROA is the "third highest EROA used by any Oregon-regulated utility,"[12] they point to the fact that PGE's actual returns over the last four years have averaged above PGE's EROA as justification for their adjustment. Using this information and the EROAs reported by Oregon-regulated utilities in their most recent SEC Form 10-K filings, Staff proposes to set PGE's EROA at 7.40%. To further justify that their adjustment is reasonable, Staff argues this rate is still "far smaller than the observed difference between the Company's actual ROA and EROA for the last 4 years but [that it] keeps the Company's EROA in line with other Oregon-regulated utilities."[13]

Q. Does Staff correctly identify the components of pension expense?

[12] Staff/600/page 8/line 20.
[13] Staff/600/page 13/lines 7-9.

A. Not exactly. Pension expense, more commonly known as "FAS 87 net periodic benefit cost,"[14] represents the cost of maintaining an employer's plan and is reported on the company's income statement. Pension expense consists of the following components:

1. Service cost - These costs represent the total increase in defined benefit obligation that results from an additional year of all employees in the plan. These costs take into account future compensation levels and then are discounted to a present value using the discount rate.
2. Interest cost - This is the increase in the overall pension obligation due to the passage of time. It is calculated by multiplying the discount rate by the Pension Benefit Obligation (PBO) adjusted for full year expected benefit payments.
3. Expected long term return on assets - This is the expected increase of plan assets associated with the passage of time during the year. Generally, it is the long-term rate of return multiplied by the Market Related Value of assets (MRVA) adjusted for current year expected benefit payments and administrative expenses paid from the trust. PGE's MRVA is calculated by determining the historical gains and losses for the past five years and multiplying each year by 20%, adding up all year's gains and losses and either adding or subtracting (depending on if the total is a gain or loss) from Fair Market value of assets.
4. Amortization - There are multiple types of Amortizations in a pension plan but the most common one for PGE is the unrecognized gains or losses associated with the difference between assumptions made at the beginning of the year for the discount

[14] PGE records its pension expense based on Accounting Standards Codification (ASC) 715, "Compensation – Retirement Benefits," which prior to July 1, 2009, was known as Statement of Financial Accounting Standards No. 87 or "FAS 87."

rate and the EROA and the actual amounts for the discount rate and EROA. These gains and losses are amortized over the average remaining service period of the plan participants.

Finally, as part of its pension expense determination, PGE must identify an expected long-term- rate of return and a discount rate.

Q. Please define EROA as used for pension accounting and how PGE's EROA is determined.

A. The EROA assumption used in setting pension expense is the <u>long-term</u> expectation of the pension fund's annual rate of investment returns. PGE annually reviews the pension plan EROA using a 20-year horizon of geometric returns based on market expectations and the asset allocation. Using its current asset allocation, PGE's benefits consultant provides PGE with a range of expected returns, with PGE generally using the 55% to 60% range given the weighting of equity-based assets in the current asset allocation. In short, PGE's EROA is a long-term measure, which accounts for the relative risk of PGE's pension investment strategy.

Q. Staff's basis for increasing PGE's EROA is based primarily on a four-year average of PGE's recent actual return on plan assets. Is this a reasonable measure for determining changes to a pension plan's EROA?

A. No. There are a couple fundamental issues with this approach. First, as we mention above, an EROA is a <u>long-term</u> measure of investment returns. Second, also mentioned above, EROA is a forward-looking expectation of returns. Alternatively, Staff's method is a backward looking, short-term measure. In other words, it is the exact opposite, which is not a reasonable or recognized method for determining EROA.

Q. Are there other issues with basing an EROA on recent historical returns?

A. Yes. Any returns that deviate from PGE's EROA are included within the amortization component of PGE's pension expense, as described above. As such, any difference between the EROA and the actual rate of return of the plan at year end is included within the calculation of pension expense for the following year. This is critical in understanding why historical returns are not used to determine EROA and why Staff's proposal is inappropriate. If you are to base a future expectation of returns on actual historical returns you are effectively double counting the gains or losses incurred within those prior periods.

Q. Is it reasonable to set PGE's EROA based on the EROAs of peer utilities?

A. No. Staff base their reasoning for this on PGE's historical returns, which, as we discuss above is an unaccepted and inappropriate method to base an EROA upon. As such, Staff's reasoning for this is unpersuasive. As can be seen from reviewing Staff Exhibit 600, Table 1, the range in EROAs for the utilities included is approximately 200 basis points. The reason for such a variation is due largely to each company's investment strategy and risk profile, which is based on many factors including a company's overall risk profile and each individual plan's unique characteristics.

Q. Please discuss Staff's argument regarding the economy post-COVID-19 as support for their adjustment.

A. Staff attempts to further support the basis of their adjustment by pointing to some generalized financial news regarding inflationary pressures for 2021 and 2022. While this news does support the fact that, as we discuss in Section II above and in PGE Exhibit 1600, PGE's forecast of labor and non-labor for 2022 is likely below market, it does not support an increase to PGE's 7.0% EROA used to forecast 2022 pension expense. To reiterate, an EROA is not a short-term measurement and while short-term outlooks do point to above average economic growth and inflationary pressures, long-term economic growth is expected to be lower.[15] In fact, the latest estimate of PGE's range of long-term portfolio return as provided by PGE's benefits consultant, provide support for an EROA below 7.0%, not above.

Q. Please summarize PGE's response to Staff's pension proposal.

A. PGE's method for determining pension expense follows well established pension accounting guidelines, which call for an EROA to be set based upon a long-term expectation of the pension fund's annual rate of investment returns. Not only does Staff's proposal base its EROA on a short-term historical review of PGE's actual return on assets, but their proposal would also effectively double count the short-term gains PGE has recognized and is amortizing within the plan.

Q. What is PGE's position regarding CUB's proposal to reduce PGE's mass transit benefit for employees?

A. While CUB's approximation that PGE's mass transit benefit costs for Integrated Operations Center (IOC) employees will be similar to the per employee cost for Tualatin Contact Center (TCC) employees appears reasonable, they ignore a key change that PGE expects to occur in 2022. As we discuss in PGE's response to CUB Data Request No. 043, TriMet has informed PGE that fare and program prices will be increasing in 2022. While TriMet has yet to share the details of the exact increase at this point, it will put upward pressure on PGE's 2022 expected cost for this program.

[15] See PGE Exhibit 1505C for a recent long-term economic forecast provided by PGE's benefits consultant.

Q. Did PGE factor this cost increase into the forecast for mass transit benefit expense?

A. No. PGE received this information after preparing this estimate for the 2022 test year. While we are not asking to increase the forecast of this program, reducing the program's forecast would only serve to compound this issue.

Q. Does PGE have other concerns with CUB's proposal?

A. Yes. PGE is concerned and disagrees with CUB's proposal to reduce this benefit based on their suggestion that it is impractical for Washington-based IOC employees to take public transit. The fact is, based upon the Department of Environmental Quality's Employee Commute Options mandatory program, PGE must provide employees with commute options to reduce the number of cars driven to work in the Portland Metro area. This requirement is no different for employees who live in Oregon or in Washington.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	Description
1501	PGE Unconstrained Calculation of PUC 3-Year Wage and Overtime Formula
1502	PGE Calculation of PUC 3-Year Incentives Model
1503	September 2021 Oregon Economic and Revenue Forecast
1504	December 2021 Oregon Economic and Revenue Forecast
1505C	Report on Long-Term Economic Variables

Exhibit 1501 is voluminous in
size and provided only in
electronic format

Exhibit 1502 is voluminous in size and provided only in electronic format

Kate Brown
GOVERNOR

Oregon Economic and Revenue Forecast

September 2021

Volume XLI, No. 3
Release Date: August 25th, 2021

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Foreword

This document contains the Oregon economic and revenue forecasts. The Oregon economic forecast is published to provide information to planners and policy makers in state agencies and private organizations for use in their decision making processes. The Oregon revenue forecast is published to open the revenue forecasting process to public review. It is the basis for much of the budgeting in state government.

The report is issued four times a year; in March, June, September, and December.

The economic model assumptions and results are reviewed by the Department of Administrative Services Economic Advisory Committee and by the Governor's Council of Economic Advisors. The Department of Administrative Services Economic Advisory Committee consists of 15 economists employed by state agencies, while the Governor's Council of Economic Advisors is a group of 12 economists from academia, finance, utilities, and industry.

Members of the Economic Advisory Committee and the Governor's Council of Economic Advisors provide a two-way flow of information. The Department of Administrative Services makes preliminary forecasts and receives feedback on the reasonableness of such forecasts and assumptions employed. After the discussion of the preliminary forecast, the Department of Administrative Services makes a final forecast using the suggestions and comments made by the two reviewing committees.

The results from the economic model are in turn used to provide a preliminary forecast for state tax revenues. The preliminary results are reviewed by the Council of Revenue Forecast Advisors. The Council of Revenue Forecast Advisors consists of 15 specialists with backgrounds in accounting, financial planning, and economics. Members bring specific specialties in tax issues and represent private practices, accounting firms, corporations, government (Oregon Department of Revenue and Legislative Revenue Office), and the Governor's Council of Economic Advisors. After discussion of the preliminary revenue forecast, the Department of Administrative Services makes the final revenue forecast using the suggestions and comments made by the reviewing committee.

Readers who have questions or wish to submit suggestions may contact the Office of Economic Analysis by telephone at 503-378-3405.

Katy Coba
DAS Director
Chief Operating Officer

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EXECUTIVE SUMMARY

September 2021

The economic outlook remains bright. Strong household incomes, boosted considerably by federal aid during the pandemic, are the underlying driver. Consumers have no shortage of firepower if they want to and feel safe enough to spend. The key to the outlook remains translating this firepower into actual consumer spending, particularly in the hard-hit service industries. Firms today are trying to staff up as quickly as possible to meet this increasing demand. The actual number of jobs created this year will be the largest on record in Oregon. The state's labor market is now expected to regain all of its lost jobs by next summer, or one quarter sooner than in the previous forecast.

While these dynamics remain intact, the risks are weighted toward the downside. Growth in a supply-constrained economy is challenging. Firms are struggling with supply chains and a tight labor market. Wages are rising quickly to attract and retain workers. Prices are increasing as demand continues to outstrip supply. On top of this the current delta wave of the pandemic complicates the immediate term outlook. What matters most economically are shutdowns. A modest pullback in consumer spending in a few categories will not lead to mass layoffs. If anything, any slowing in spending today will likely turn into stronger gains in coming quarters.

This cycle is different. The current recovery will be faster, more complete, and more inclusive than recent experiences coming out of the tech and housing bubbles. As some of the pandemic-specific challenges fade, the underlying economy is on solid footing due to the strength of corporate and household balance sheets.

In September of odd-numbered years, the revenue forecast closes out the biennium than ended on June 30th. At this time, the Close of Session forecast is calculated by folding any tax law changes made during the legislative session into the May 2021 outlook. This sets the bar for Oregon's balanced budget requirement and its unique kicker law. Changes to tax law were relatively small in the 2021 session, with a net revenue impact of -$3.6 million to General Fund resources in the 2021-23 budget period.

The September forecast also reveals where revenues landed in the prior budget period. In a typical year, there are few surprises, since tax collections are relatively small during the early summer. This year was different. Due to a delayed tax filing deadline, much uncertainty remained following the May forecast. When the forecast was developed, the peak tax season had just begun.

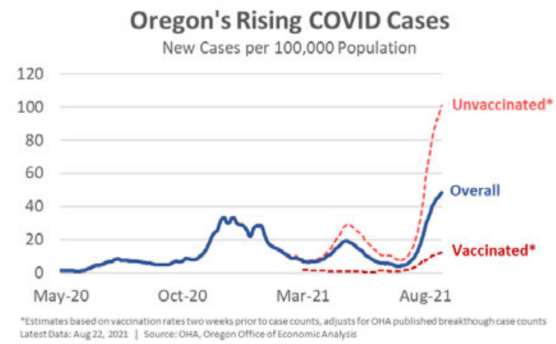
By the end of the fiscal year, the 2021 tax season turned out to be a very big one. Collections of personal income taxes, corporate income taxes, lottery sales and the new Corporate Activity Tax all surged. Recent withholdings of personal income taxes are up 17% relative to last year. Payments during the tax season were strong as well, led by collections from high-income taxpayers. A $1.9 billion personal income tax kicker credit is slated for tax year 2021. The median taxpayer can expect to receive a credit of $420, while the average is estimated to be $850.

The strong revenue growth seen during the 2019-21 biennium put a cap on a decade of unprecedented expansion in Oregon's General Fund revenues. Over the past decade, General Fund revenues have almost doubled from around $12 billion per year to around $24 billion. Over the decade as a whole, kicker payments amounted to $2.6 billion, reducing cumulative General Fund resources by 2.6 percent. Last biennium, kicker payments took away half of the General Fund growth. Looking forward, the current $1.9 billion kicker reduces 2021-23 revenues as well.

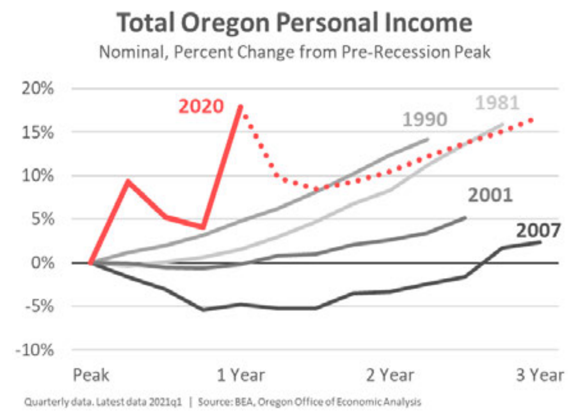
ECONOMIC OUTLOOK

The economic outlook remains bright. Strong household incomes are the underlying driver. Increased consumer spending in the quarters ahead will result in robust job growth. These dynamics remain intact. The current delta wave of the pandemic complicates the immediate term but does not alter this medium term trajectory of the overall economy. No doubt, increased COVID outbreaks will continue to impact supply chains, workplaces, and even soften consumer demand for certain in-person activities. These issues are likely to persist as long as the pandemic remains.

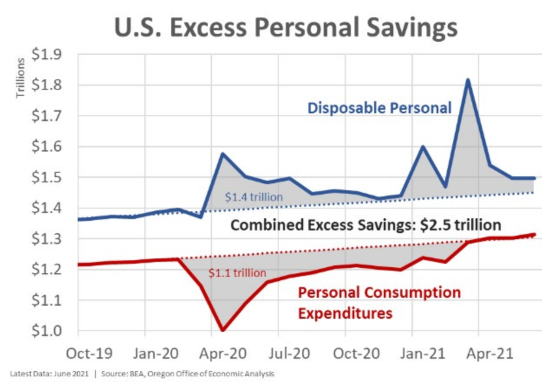
That said, in terms of the economic risks during the pandemic, shutdowns are what really matter. A modest pullback in consumer spending in a few categories will not lead to widespread layoffs. More stringent health restrictions will, as has been the case twice so far during the pandemic here in Oregon. Given the underlying strength in household finances, softer consumer spending today on air travel, indoor dining, movie theaters or the like, should lead to stronger gains in the months ahead when it is safer from a health perspective.



The primary reason for the strong economic outlook are household balance sheets. Consumers today have no shortage of firepower when it comes to their ability to spend, if they want to and/or feel safe enough doing so. Current incomes are higher than before the pandemic. Much of this increased income is thanks to direct federal aid. Here in Oregon, unemployment insurance has boosted incomes by more than $11 billion while the recovery rebates added nearly $13 billion. Combined this represents about an 11 percent boost to incomes in the state in the past 18 months. Federal policy has accomplished its job of keeping households above water during the pandemic. More encouragingly, underlying income that excludes the direct federal aid has not only recovered but has nearly regained its pre-pandemic trend.



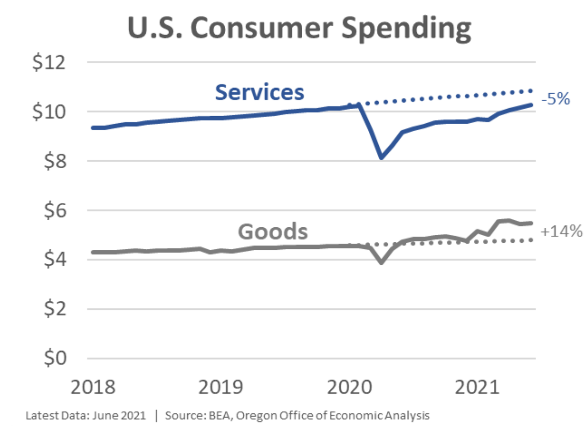
Beyond current income, households have additional means to spend in the months and years ahead, propelling economic growth. Total household savings nationwide has increased considerably as total spending has been below trend during much of the pandemic. Excess household savings – those above and beyond what would have been expected absent a pandemic – have boosted bank accounts by $2.5 trillion. Local financial institutions indicate they are seeing similar patterns here in Oregon.



Furthermore, consumers generally have lower debt levels today as credit card balances have been paid down and fewer new charges rung up. Plus the stock and housing markets are at historic highs, allowing households to tap their wealth should they want or need to.

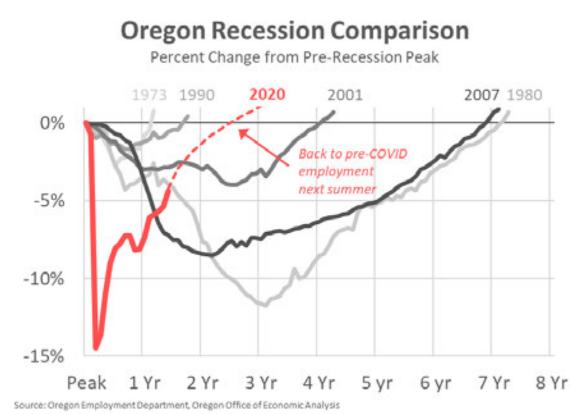
The key to the outlook is translating these sources of spending into actual spending. Whether or not the excess savings is drawn down or the wealth is tapped is somewhat immaterial. The strong outlook does not rest of these outcomes, but if they should come to pass, then the outlook would be even stronger. Rather, the outlook rests on the continued increase in spending out of current income as consumers feel safe enough doing so. That is why the delta wave is potentially worrisome in the immediate period, but the longer-run outlook remains intact.

Specifically, the overall labor market recovery continues to rely on consumer spending shifting back into services. In recent months, Americans are going out to eat nearly as much as pre-pandemic, but overall spending on services remains lower due to other sectors like health care where elective surgeries and routine dentist appointments continue to be delayed. The gap between service spending and the pre-pandemic trend remains noticeable at 5% as of June, but the gap is closing. On the other hand, sales of physical goods continue to be robust and are holding steady at double-digits above pre-pandemic trends. Strength is seen across nearly all categories from autos to groceries, home improvement to recreation equipment, and the like.



Bottom Line: The shift in consumer spending out of goods, or at least back into services is very pro-jobs. Service industries are labor intensive. It takes considerable man- and womanpower to give care and serve food to customers. With the increasingly strong demand, firms are trying to staff up as quickly as possible.

Job growth this year has already been robust, with expectations that these gains will continue. Over the full year, from 2020q4 to 2021q4, Oregon is expected to create 100,000 jobs, the largest on record. Of course Oregon is a larger place today than in generations past, but in growth rates this would be the largest percentage increase in employment since the heyday of the timber industry back in the 1970s. Oregon is expected to recover all of its lost jobs by 2022q3, one quarter earlier than in the previous forecast. Clearly, this cycle is different. The recovery will be faster, more complete, and more inclusive than the recent experiences coming out of the tech and housing bubbles.



The risks to this outlook are weighted toward the downside due to potential supply constraints. If firms are unable to hire as quickly as they would like, or if demand softens a bit more than expected during the delta wave, growth will still be robust in the year ahead, however not quite as robust as the baseline forecast expects. A full labor market recovery may not happen until fall or winter 2022 as a result. Such a recovery would still be fast by historical standards, but a bit slower than the current forecast assumes. Conversely, the outlook is not without upside risks as well. If the exceptionally strong job gains experienced this year continue at the same rate, a full labor market recovery could occur by early next year.

The Labor Market will Remain Tight

While the good news is incomes and consumer demand is strong, the flipside of this dynamic are the production and supply chain issues that restrict growth from being even stronger. See our office's May 2021 forecast for more[1]. Economic growth in a supply-constrained economy is challenging. Labor is the chief constraint today, in part because labor runs through everything. A factory cannot produce more by adding an additional shift without workers, there would be fewer shipping delays with more truck drivers, and so forth.

Currently, businesses in Oregon and across the country are advertising record job openings. They are looking to staff up as quickly as possible to accommodate strong consumer demand. These increases in job openings are seen across all industries, even as the biggest gains are seen in the sectors most affected by the pandemic, like leisure and hospitality.

At the simplest level, job openings are through the roof because businesses are trying to staff back up to pre-COVID levels, if not higher. However other labor market dynamics further exacerbate the number of job openings. The number of quits is up, meaning firms need to fill their normal vacancies plus the newly vacated positions as well. The same goes for any uptick in retirements a business may see. Additionally, the overall labor supply is lower today than before the pandemic. The labor force participation rate nationally is down 1-2 percentage points. This means that even the normal, everyday turnover a business experiences in its workforce, it will take longer to fill as relatively fewer workers are looking for work today. This too creates more job openings.

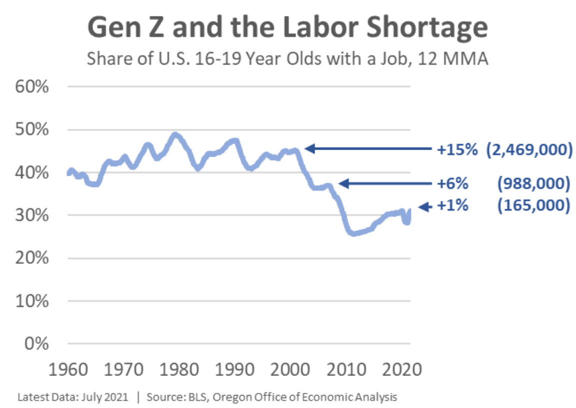
Well, what about labor supply? There are structural, frictional, and cyclical issues at play. The overall labor supply will continue to increase in the months and years ahead. However, it is important to keep in mind that the labor market will remain tight even as some of the pandemic-specific issues subside. More than half of all job vacancies in Oregon were difficult to fill back in 2018 or 2019. The labor market will return to those dynamics, which does represent some improvement from the acute labor shortages experienced this summer.

The primary reason the labor market will remain tight in the years ahead are structural issues like demographics. The economy is experiencing a large, steady flow of retiring Baby Boomers each and every year. While the inflow of Gen Z workers into the economy is even larger, meaning the labor supply is increasing, the *net* gains are smaller and increasing at a slower pace than in decades past. The demographic drag is a relative, and not an absolute one, particularly in a place like Oregon which continues to see in-migration among working-age households.

The pandemic has done little to alter these dynamics. On one hand the number of Americans not looking for work specifically because they say they are retired has picked up, however the number of new Social Security beneficiaries has actually slowed noticeably. New research from the Kansas City Fed[2] squares these seemingly opposite data points by noting the increase in retirements in the monthly household survey isn't due to larger outflows into retirements, but rather due to fewer older Americans reentering the labor market during the

[1] See pg 5 https://digital.osl.state.or.us/islandora/object/osl%3A969229/datastream/OBJ/view
[2] https://www.kansascityfed.org/documents/8240/eb21NieYang0811.pdf

pandemic. The net result is more people saying they are retired, but the implications for future labor supply are different. Expectations are that some older workers will return to the workforce when it is safer to do so.



On the other hand, there is an indication that teenagers are participating in the labor market at their highest rate since before the Great Recession. Overall teenage employment remains lower than a couple decades ago, but the relative size of these potential workers is very large. Every percentage point increase in teenage employment is a couple hundred thousand workers. A return to mid-2000s employment rates would be an additional million workers in the U.S. economy. A return to 1980s or 1990s employment rates would be nearly 2.5 million more workers. While such changes are unlikely to happen overnight, a stronger economy with more job openings and higher pay that pulls in more inexperienced workers would help dampen the bigger picture demographic and structural changes in the labor market.

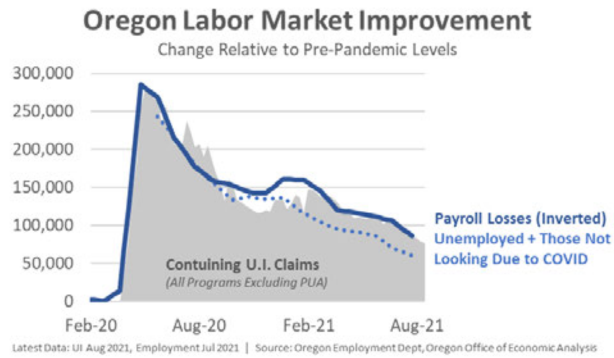
Frictional labor supply constraints are that it takes time to hire workers, to get the paperwork completed, to begin training and the like. From an operations perspective it is easier to fire millions of workers in one fell swoop than it is to onboard the same number. This reality does give some credence to the theory that there is some natural speed limit to the economy. Monthly job gains can only be so large due to these process and timing issues. Frictional constraints are currently exacerbated today by the simple fact there are millions of firms nationwide, and thousands here in Oregon that are all trying to hire workers at the same time. This increased competition – largely for the same pool of labor – does mean that not all businesses are able to fill their openings in a given period of time, even if they wanted to.

Finally, the main labor supply constraints today are cyclical. Nationally labor force participation rates are down more than a percentage point. The key question is when will workers return in greater numbers? At a base level the answer is workers will return when they need the money and they feel safe enough doing so during an ongoing pandemic.

The first, and really only constraint today many people want to discuss are the enhanced unemployment insurance benefits. As detailed in our office's previous forecast, the average UI check in Oregon is equal to 100% wage replacement for the laid off worker. For many part-time and/or lower-wage workers it is greater than that given the $300 per week federal plus up is a lump sum given to all who qualify. For example, the average former leisure and hospitality worker on unemployment insurance is receiving north of 130% wage replacement. Of course that excludes tips, and current wages are higher today than before the pandemic so the opportunity costs are different, but still, it is clear that UI is a disincentive for some workers. To the extent that it is, the enhanced benefits end the first week of September.

However, as discussed throughout this report, overall household finances are strong. Clearly UI is a big piece of that, but not the entire picture. Recovery rebates are a bit larger than UI overall, boosting total incomes. Given this, and the stockpile of excess savings many households have accumulated during the past year, it is not likely that businesses will suddenly see a flood of job applicants as soon as the enhanced UI benefits end in a week or so. In fact, preliminary analysis of the limited data available in the states that ended UI early indicate that job growth did not suddenly accelerate relative to the non-cutoff states. As such, it is more likely that once some of that excess savings is drawn down and households need more money to pay the bills – hopefully in a safer health environment as well – then labor supply will likely pick up.

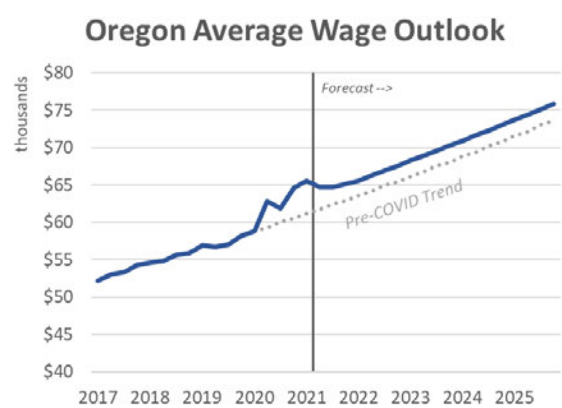
Importantly, even as UI is a big, maybe the biggest piece to the labor supply puzzle it is not the only piece nor is it immovable. As the nearby chart shows, the number of Oregonians receiving unemployment insurance benefits is moving in tandem with payroll job counts, and the number of unemployed and those not looking for work due to the pandemic. These different measures of the health of the labor market are moving together.



Now, this does not mean that job growth could not be faster absent the enhanced benefits. But it also means that there is not this large pool of potential labor that is immune to overall labor market conditions. As job opportunities, and wages have increased, the number of Oregonians receiving benefits has decreased. This is not due to benefit exhaustion, but rather individuals taking these more-plentiful and better-paying jobs.

That said, these dynamics due change after September 4th when the enhanced unemployment insurance benefits end. Preliminary analysis indicates that 70-80,000 Oregonians will lose their benefits and be ineligible to continue onto other UI programs. Many of these individuals are already counted in the potential labor supply numbers in terms of being unemployed or not looking specifically due to COVID. As such, these traditional measures of labor supply may not increase noticeably. However the effective labor supply is likely to increase modestly in the months ahead as households draw down their savings, labor market conditions continue to improve, and job openings prove more enticing.

Finally, wages are a key piece to the labor market discussion. Today, average wages in Oregon are up 10 percent over the past 18 months. More importantly they are up 5 percent relative to the pre-pandemic trend, which was already fast growth due to the strong economy in the latter parts of last decade.



Crucially, these wage gains are seen throughout the economy. Average wages are not just higher due to compositional effects such as the pandemic layoffs disproportionately impacted lower-wage workers. They did initially. However since then, underlying wage gains have nearly overtaken these compositional changes seen so far in the economy. For instance, wages in leisure and hospitality now stand nearly $1 per hour, or about 5% higher than pre-pandemic trends both nationally and here in Oregon.

A key dynamic coming out of the Great Recession was the fact that the economy suffered from inadequate demand. With lower levels of consumer spending, business did not need to hire as quickly, and with a large pool of unemployed individuals, they did not need to pay top wages to attract and retain talent. Labor force participation rate sagged and took years to recover.

This cycle is different. Consumer demand is strong given household incomes. Firms are looking to staff up as quickly as possible, and wages are rising quite quickly as they try to attract and retain workers in today's tight labor market. Looking forward, it is hard to see how labor supply will remain depressed indefinitely. The more-plentiful, and better-paying job opportunities will continue to bring workers in off the sidelines. This should be the case especially this fall as the federal programs end and savings is drawn down. Even so, labor market dynamics will go from an acute shortage to regular tightness given underlying economic conditions. The wildcard remains the pandemic itself in terms of how it impacts household decisions regarding health, and any ongoing disruptions to our everyday lives.

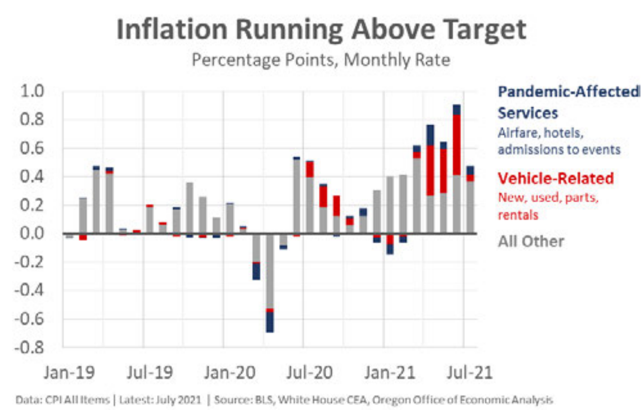
Persistent Inflation is a Risk

In recent months inflation is running hot. Much of this can be explicitly tied to reopening sectors of the economy, or shortages in the automobile industry. However, even stripping away these likely temporary issues, the risk remains that underlying inflationary pressures will remain above the Federal Reserve's target moving forward. Therefore the risks are not whether inflation will be above target or not – it already is – but what exactly the Fed is going to do about it.

On the one hand, prices in recent months have surged in sectors and activities previously restricted by the pandemic. The costs for airfares, hotels, and admissions to events are up. However these prices also dropped earlier in the pandemic. The current surge is really bringing these prices in line with where they likely would have been absent the pandemic. As such, these prices will moderate moving forward.

Additionally, demand for automobiles has recovered much quicker than production has, largely due to the shortage of semiconductors needed to complete assemblies. This mismatch between supply and demand is driving the price of both new and used cars considerably higher. As computer chip production increases, and as demand slows in the face of these higher prices, the overall dynamics in the auto industry should moderate as well.

While these examples may explain a large part of the current high readings for inflation, they are not particularly interesting or pertinent to the overall monetary policy discussion. The Federal Reserve will look through temporary bouts of inflation. What the Fed ultimately cares about is persistent inflation that is higher than its 2% target on an ongoing basis. For this reason note the gray bars in the nearby chart. The All Other portion of the inflation readings are currently running at about a 4% annualized pace.



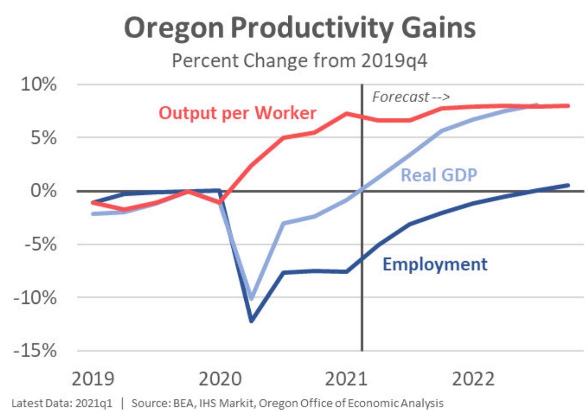
The key dynamics to watch here are the interactions between actual inflation, expectations about future inflation, and underlying wage and income growth. Of course all three of these are point up today, but what does the intersection between them look like in 3, 6, 9 months from today? Without the belief that prices moving forward will be higher, it is harder for firms to raise prices. Similarly for income gains, if consumers cannot afford the higher prices without sacrificing quantities consumed, then prices will slow accordingly. Such inflationary pressures will peter out on their own.

The ultimate economic risk lies in inflation proving more persistent than believed such that the Federal Reserve steps in and raises interest rates to cool the economy. Not only would this slow economic growth, but in some historical periods, it has even caused a recession. The Fed has not yet laid down hard markers on what it will or will not tolerate when it comes to inflation, nor its beliefs on just how much is transitory versus persistent. However the answers to these questions in the quarters ahead will matter considerably. The underlying stage is set for inflation that is modestly, yet persistently above target, but whether the economy actually experiences that or not is unknown.

Today the Federal Reserve is nearing agreement on the timing and pace of tapering, or reducing its long-term asset purchases. Many market participants expect the announcement in the next month or so with the actual tapering to begin late this year or early next. In terms of interest rates, market participants expect the first rate hike to occur in late 2022 or early 2023. The risks on the timing are largely to the downside, or for these policy actions to occur at later dates.

One potential saving grace for inflation could be productivity growth. Not only does increased productivity raise the overall speed limit of the economy, but it also helps firms absorb higher costs without pushing them all forward onto consumers. If a business is able to produce more output with fewer workers, it makes the cost pressures on their inputs (parts and labor) more manageable. As a result, inflation in the overall economy can be kept in check.

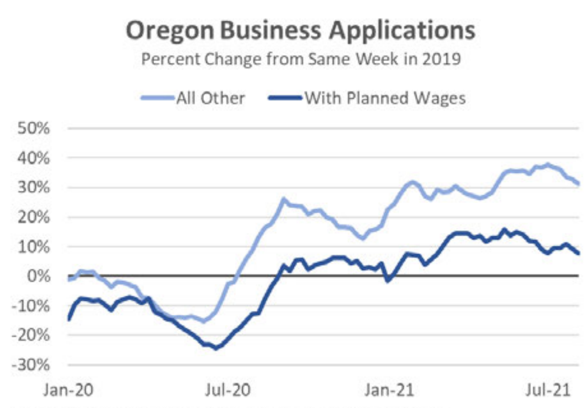
To date, productivity has increased during the pandemic. Output per worker in Oregon is up around 8 percent. Much of these gains have been forced onto firms where they must try and make do with what they have. Consumer demand is strong, and the firms have limited staff and production capabilities.



However, over the medium- and long-run firms can better plan for their investments which tend to raise productivity as well. Nationally, new orders for capital goods and announcements of capital expenditures are up indicating businesses are looking to invest in new plants, equipment, and software moving forward. This should make managing price pressures easier in the years ahead.

Two final notes on productivity and inflation.

First, new business formation is strong since the start of the pandemic. New firms tend to bring new products and services to the economy, and improve efficiencies and raise overall productivity. Should this new generation of businesses do likewise, productivity should continue to improve.



Second, increased production capacity should also relieve price pressures. If products are no longer supply-constrained, increased demand should result in more production and not just higher prices. As detailed in our office's previous forecast, a number of manufacturing subsectors – food, machinery, and wood products in particular – were already at their historical limits in terms of capacity utilization. They need to expand in order to meet demand. However a similar argument applies to services like child care. A national boost to increase the supply of these, be they semiconductors, housing, or child care, as is currently being debated in Washington D.C. as part of the reconciliation bill, could ultimately prove disinflationary as it would remove current choke points in the overall economy.

Oregon's Latent Labor Force

Oregon's long-run economic and revenue outlook is closely tied to the state's population forecast. The more Oregonians, particularly working-age Oregonians, the more income earned and taxes paid. Plus a larger population increases demand for new housing construction, additional pizza parlors, and the like which generates even more economic activity. However, the state does not necessarily have to experience faster population growth to see stronger economic and revenue gains. The main reason is there are already plenty of Oregonians today who are underutilized. Businesses have a wealth of potential employees, if they are able to or willing to hire from disadvantaged populations that have traditionally been excluded from the economy. In our office's previous forecast[3] we detailed how there are historical inequities built into what economists generally define as full employment.

A new report titled "Reimaging Full Employment"[4] from the Roosevelt Institute examines what the economy could look like if some of these historical inequities were addressed in the United States. What follows is a summary of what they may look like here in Oregon based on our office's calculations of a few specific scenarios.

Specifically, what would Oregon's long-run labor supply look like if we closed the educational attainment gap between white, non-Hispanic Oregonians and communities of color? How many more workers could local businesses hire if employment rates across all segments of the population were at their historical maximum? What if women were hired at the same rate as men? All three of these potential scenarios address a specific labor market inequity, and in doing so would boost the overall potential of Oregon's economy, including sales for local businesses and the associated taxes paid to fund public services.

Note: These scenarios and analysis is built off of potential changes seen across different cohorts of Oregonians over the next decade. Specifically these cohorts are grouped by sex (male and female), educational attainment (college graduates and non-college graduates), race or ethnicity (white, non-Hispanic, and Black, Indigenous, and People of Color), and eight different age groups (16-24, 25-34, 35-44, 45-54, 55-64, 65-74, 75-84, 85+). There are 64 cohorts in total. The scenarios also account for the increasing diversity among Oregonians, a trend expected to continue in the years ahead.

The upshot of addressing these employment disparities is Oregon, is that they have the potential to boost the labor supply much more than any realistic increase in migration ever could. By hiring to a greater degree from Oregon's existing residents, firms would be able to tap into a much larger pool of labor in order to expand and grow. Such an outcome would be a win-win for society and the economy.

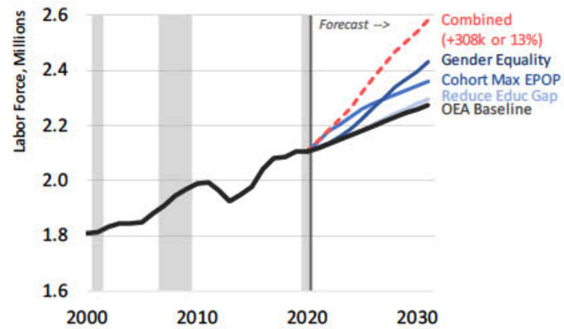
The table below summarizes the findings of these three potential scenarios. The first set of numbers indicate how much larger labor supply would be, above and beyond our office's baseline outlook, if a particular disparity is addressed. The final number converts this into a population growth rate equivalent. Over the decade ahead, our office expects Oregon's population to increase by 0.8 per year. Every increase of a tenth of a percent is a massive change in the number of potential workers in the regional economy.

[3] See pg 14 https://digital.osl.state.or.us/islandora/object/osl%3A969229/datastream/OBJ/view
[4] https://rooseveltinstitute.org/wp-content/uploads/2021/07/RI_FullEmployment_Brief_202107.pdf

Oregon's Latent Labor Force

Scenario Addressing Disparity	Labor Force Increase in 2031 Number	% Above Baseline	Annual Population Growth Equivalent
Gender Equality (Female Employment Rates Match Male for All Cohorts)	156,000	6.8%	0.54%
Maximum Historical Employment Rate for All Cohorts	86,000	3.8%	0.33%
Eliminate Educational Attainment Gap among Younger Cohorts	21,000	0.9%	0.12%
Combined	308,000	13.5%	1.00%

Source: BLS, Census, IPUMS-USA, Roosevelt Institute, Oregon Office of Economic Analysis



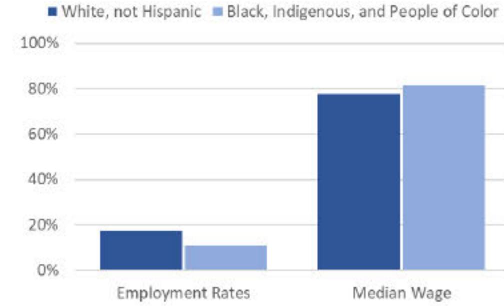
The single largest inequity is the gender gap. Women are employed, and earn lower wages than men. Increasing employment opportunities for half the population (women) really moves the overall economic needle. This is easier said than done, of course. In particular the largest gender gap in terms of employment is seen between moms and dads. To really address this disparity, the availability and affordability of childcare and extended care after school would really need to be addressed. The unemployment rate between women and men is not noticeably different, but that's largely due to many moms indicating they are not looking for work specifically because they are taking care of the home or family. Flexible schedules, and working from home are also likely needed to help address the gender employment gap. Ultimately if women in Oregon were employed at the same rate as their male counterparts across each cohort, Oregon's labor supply would be more than 150,000 larger than forecasted in the decade ahead. This boost would be equivalent to seeing population growth per year of 1.3 percent instead of the baseline of 0.8 percent.

The scenario with the second largest boost to Oregon's labor supply really boils down to employing individuals at the highest rates experienced in recent decades when examining each cohort based on age, sex and educational attainment. For example, if all women of the same age and educational attainment were hired at similar rates, how much larger would Oregon's labor supply be? These are not either/or scenarios. They simply show how large the latent labor force is even within similar groups of workers. All told, this scenario would boost Oregon's labor force by more than 80,000 workers in the decade ahead. This is equivalent to seeing population growth per year of 1.1 percent instead of the baseline of 0.8 percent.

The third scenario modeled here eliminates the educational attainment gap between white, non-Hispanic Oregonians and their Black, Indigenous, and People of Color peers. This scenario only closes the college graduate gap among the youngest age cohorts and not for the entire population. From a policy perspective it would be more likely to target higher college enrollments among recent high school graduates than it would be to send middle-age and older Oregonians back to college campuses.

Wages are the Real College Gain

Percent Difference between College Graduates and Non-College Graduates, Prime-Age Oregonians (25-54 Yr Old)



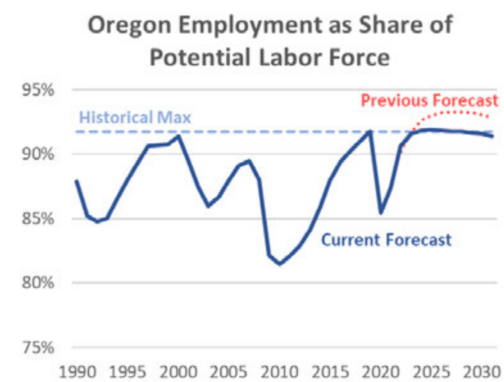
Data: 2019 | Source: IPUMS-USA, Oregon Office of Economic Analsyis

Note that while raising educational attainment and closing the gap does boost Oregon's potential labor force by the equivalent of about one-tenth of a percentage point of population growth a year, such changes are relatively small compared to the other two scenarios. The reason is twofold. First, the educational attainment gap is only closed for the youngest cohorts, leaving most of the labor force unchanged.

Second, the largest differences related to educational attainment are not employment-related, but income-related. Yes, employment rates are higher for college graduates, but wages are considerably higher. The median wage for both white, and BIPOC college graduates in Oregon is about 80% higher than it is for non-college graduates of the same race or ethnicity. Therefore the biggest economic and societal boosts to raising educational attainment and addressing racial disparities will not be seen in the raw number of workers in Oregon. Rather, the bigger boosts will be seen in the income, poverty, homeowner, and taxes paid data.

Bottom Line: Addressing economic disparities raises the potential of the entire economy. Local businesses have a larger pool of workers to choose from than many believe due to the historical underutilization of many segments of the population. Faster migration in the years ahead will grow the economy, however even if such gains do not materialize, there remains considerable upside risk to Oregon's economic and revenue growth.

Long-Term Forecast Changes



While the short-term economic outlook remains largely unchanged, and the long-term labor supply concerns misplaced, our office's long-term employment forecast is lowered. This is to better align the jobs outlook with our office's demographic forecast. This adjustment is needed as the past few forecasts have raised that long-term employment outlook above and beyond what would historically be justified given the underlying demographics.

In particular the longer-term outlook is lowered noticeably for public education, where underlying demographics point toward very little growth. The size of the K-12 student population in addition to those in their traditional college-age years is expected to grow very modestly in the decade ahead. As a result, school district and college campus employment is lowered relative to previous forecasts to better match these demographics.

Additionally, modest downward revisions are seen in professional and business services and also in leisure and hospitality where our office's population-adjusted outlook now is lower than pre-pandemic expectations.

The longer-term income outlook is not lowered in the same fashion as a slightly stronger average wage per worker outlook offsets the changes to employment, leaving total income largely unchanged.

Regional Comparisons

Coming out of the Great Recession it was the nation's largest urban areas that turned around. Being home to the most diversified economies also meant less exposure to housing and government, the two biggest drags last cycle. In part due to the more-plentiful job opportunities, and in part due to increased preferences for urban living, strong population gains to the larger metropolitan areas reinforced these economic dynamics, driving a stronger recovery in urban areas than in many smaller metros and rural communities.

This cycle is different. As detailed in our office's previous forecast[5], Oregon's large urban areas are lagging the rest of the state. This is due to a number of factors including less business travel, more working from home, and all those great urban amenities being transformed into disamenities when they cannot be used or enjoyed during a pandemic.

[5] See pg 15 https://digital.osl.state.or.us/islandora/object/osl%3A969229/datastream/OBJ/view

Over the medium- and long-run, the Portland economy is expected to regain its position near the top of the pack. Economic growth is fundamentally about how many workers a region has and how productive each worker is. Population growth will strengthen during the recovery, bringing with it an influx of new workers and new firms that will outpace much of the state and nation. Human capital accumulation and agglomeration effects will boost urban economies to a greater degree. Plus urban areas tend to have larger pools of financial and physical capital to help drive productivity gains in the years ahead. The wildcard in terms of downtown Portland and job centers more broadly remains working from home. Ultimately where that lands, be it a couple days a week versus fully remote, will go a long way to determining the impact on commercial real estate.

However, with the pandemic still raging, the Portland regional economy is still suffering more than the rest of the state. In particular it is the in-person activities that cities usually thrive on that are seeing slower gains than elsewhere around the state. It is somewhat of an open question just how much of these differing trends can be chalked up strictly to the pandemic itself, versus how consumers behave differently across the state in response to the pandemic. Nonetheless, Portland's in-person recovery is lagging the rest of the state.

In the Portland region, the number of seated diners at restaurants is only halfway back to where it was before the pandemic, compared with a full recovery in other parts of the state, at least among restaurants using the OpenTable reservation software. Note that in recent weeks, the weakening in indoor dining is not seen in the Portland region but elsewhere in the state where cases and hospitalizations are much higher during the delta wave, and vaccination rates are likewise lower.

One bright spot for tracking the recovery in downtown Portland is that video lottery sales in the urban core have fully recovered, and set records this summer. While an imperfect measure, it does indicate that foot traffic and consumer spending are returning. However, in keeping with the broader patterns in the economy, these gains in video lottery sales are larger in the Portland suburbs, and strongest elsewhere across the state.

Lastly, the relative economic performance is seen in the employment data as well. Leisure and hospitality employment in Multnomah County remains down three times as much as in the Portland suburban counties, and ten times as much as in the rest of the state, with data available through July.

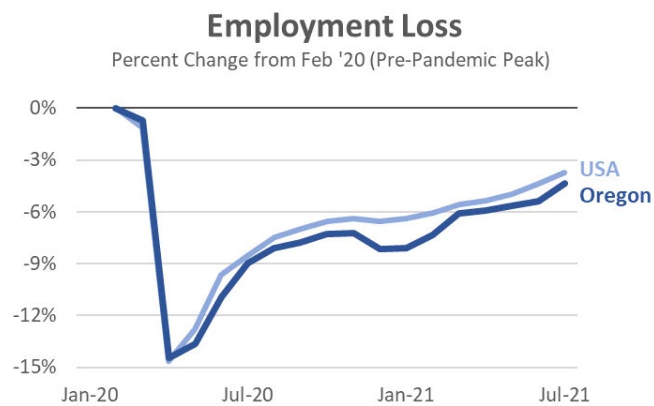
Two major contributing factors remain the lack of business travel during the pandemic, and the increased number of people working from home. Both issues work to lower the number of consumers in the urban core, while simultaneously boosting their home markets, be they out of state or in the suburbs.

State Comparisons

COVID-19 has hit Oregon's economy approximately the same as it has nationwide. Across states, Oregon remains in the middle of the pack when it comes to employment, the unemployment rate, and wages. This is different than in past recessions when Oregon has suffered more than the typical state. One primary reason is the nature of the pandemic shock affected all areas, and in particular those with an older population, and states more reliant on travel and tourism to a greater degree. As such Oregon has an average exposure to the pandemic. This is unlike back in the dotcom and housing busts, when Oregon had a larger exposure to the most affected sectors than national average.

In terms of employment since the start of the pandemic, Oregon lags the national average by 0.6 percentage points as of July 2021 (-4.4% in Oregon compared to -3.7% nationwide).

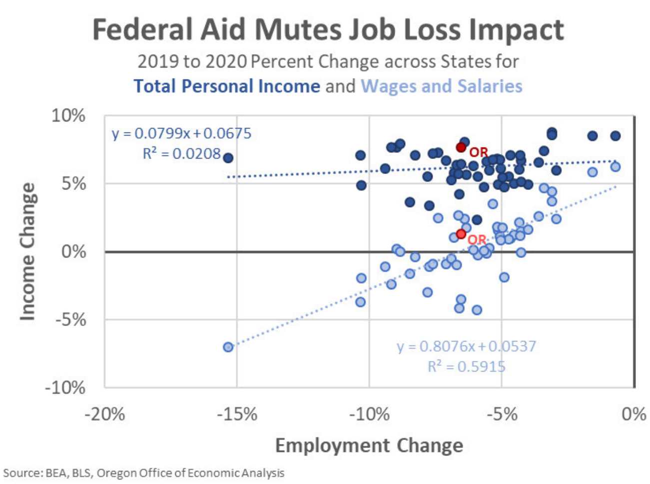
This gap is almost entirely due to local trends in education and leisure and hospitality. Unlike some states, Oregon has had public health policies in place including distance learning and periods of takeout-only food service. While these health policies have certainly kept Oregon COVID cases and deaths below the national average, it likely has resulted in some slower employment gains in the most-affected industries.



Keep in mind that in the big picture, Oregon's economy is recovering in-line with the nation. While Oregon today is slightly lower than the average state in terms of employment, Oregon is usually considerably lower. Looking forward our office's forecast expects Oregon to resume its above-average growth during the expansion in the years ahead, like the state always sees during good economic times.

As discussed throughout this report, the strong federal policy response to the pandemic has kept households and the overall economy afloat. Importantly when looking across states, federal policy has muted much of the direct economic impact of the pandemic and any variation around the country.

Typically local incomes vary to a large degree based on local economic conditions. Not so during the pandemic, as seen in the nearby chart. While the change in wages and salaries across states is tightly linked to job losses (light blue dots) the same cannot be said for total personal income (dark blue dots).



The main reasons for this are that direct aid to households went to all states, and to nearly all American. For instance, every state received recovery rebates.

Additionally, the enhanced unemployment insurance benefits kept laid off workers financially whole, on average. As such, states that saw larger job losses during the pandemic, saw more UI benefits paid, offsetting the loss of wages and keeping total personal income relatively steady. This is unlike past cycles insofar as UI typically only replaces a fraction of lost wages from laid off workers (in Oregon it was about 60-65% pre-pandemic) but thanks to the federal enhancement, the average unemployed workers is seeing full wage replacement during the pandemic.

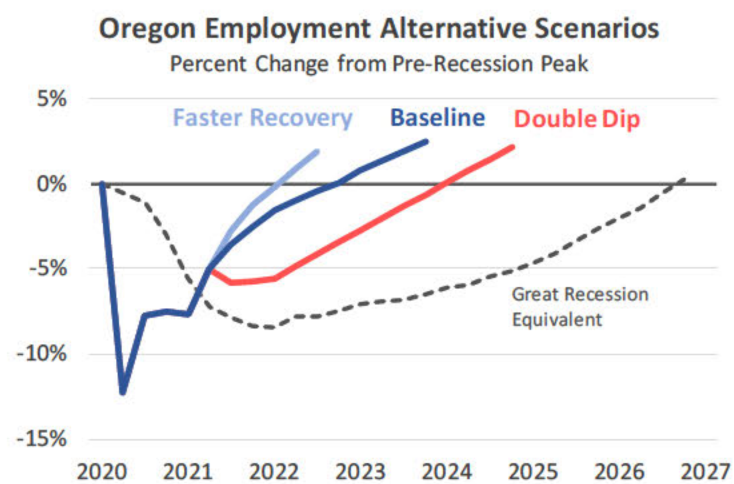
Moving forward as the economy improves and temporary federal policies expire, expect states to once again see greater variation in their growth. Jobs and wages will tend to increase fastest in the places with stronger population gains and better demographics, which includes Oregon and most western and southern states.

A more complete summary of the Oregon economic outlook and forecast changes relative to the previous outlook are available as Table A.2 and A.3 in Appendix A.

Alternative Scenarios

The baseline forecast is our outlook of the most likely path for the Oregon economy. As with any forecast, however, many other scenarios are possible. While the pandemic is waning and the vaccines so far are working against the known variants, some risks do remain. The two alternative scenarios below are not the upper and lower bounds of these outcomes. These alternative scenarios are modeled on realistic assumptions that are somewhat more optimistic or pessimistic than the baseline.

Alternative Scenarios **Sept 2021**



	2020	2021	2022	2023
Employment				
Baseline	-6.5%	2.4%	4.2%	2.4%
Faster Recovery	-6.5%	2.9%	5.7%	3.0%
Double Dip	-6.5%	0.9%	1.7%	2.9%
Unemployment Rate				
Baseline	7.6%	5.8%	5.1%	4.0%
Faster Recovery	7.6%	5.5%	4.3%	3.9%
Double Dip	7.6%	6.9%	8.0%	6.1%
Personal Income				
Baseline	7.6%	6.4%	1.4%	5.1%
Faster Recovery	7.6%	8.0%	1.3%	5.1%
Double Dip	7.6%	3.3%	-0.2%	5.2%

<u>Optimistic Scenario – A Faster Recovery</u>:

The current delta wave ends sooner than anticipated, resulting in hardly any economic damage. The underlying strength in income and consumer spending propel the economy to full health by early 2022, leading the overall cycle to more closely resemble the traditional recovery from a natural disaster. Between more inoculations and increased investments in public health, any potential seasonal wave this fall or winter is kept at bay. The current supply constraints on the economy also prove temporary with no persistent price pressures emerging next year. As the pandemic fades, labor supply accelerates allowing firms to hire and expand in an improving economy.

<u>Pessimistic Scenario – A Double-Dip Recession</u>:

The current delta wave worsens, eventually leading to mass layoffs on par with last winter. The economy does not crater, given the underlying strength in incomes, wealth, and savings. However thousands of jobs are lost in the next couple of months in the most affected, in-person service industries. This could be due to shutdowns and more stringent health policies, or simply enough consumers pulling back out of fear of the virus. Complicating matters is the fact that federal aid programs are largely gone. There is no more PPP money for business or enhanced unemployment insurance benefits for laid off workers. The economic damage to the most impacted sectors is larger than it was earlier in the pandemic as a result. That said, as cases decline – and they eventually will – the underlying strength in the overall economy remains. Consumers will return, leading to strong job creation next year. Overall Oregon's economy does not fully return to health until late 2024, or about two years later than under the baseline outlook. The key will be how much permanent damage accumulates in the form of business closures and layoffs during the delta wave.

REVENUE OUTLOOK

Revenue Summary

In September of odd-numbered years, the revenue forecast closes out the biennium than ended on June 30th. At this time, the Close of Session forecast is calculated by folding any tax law changes made during the legislative session into the May 2021 outlook. This sets the bar for Oregon's balanced budget requirement and its unique kicker law.

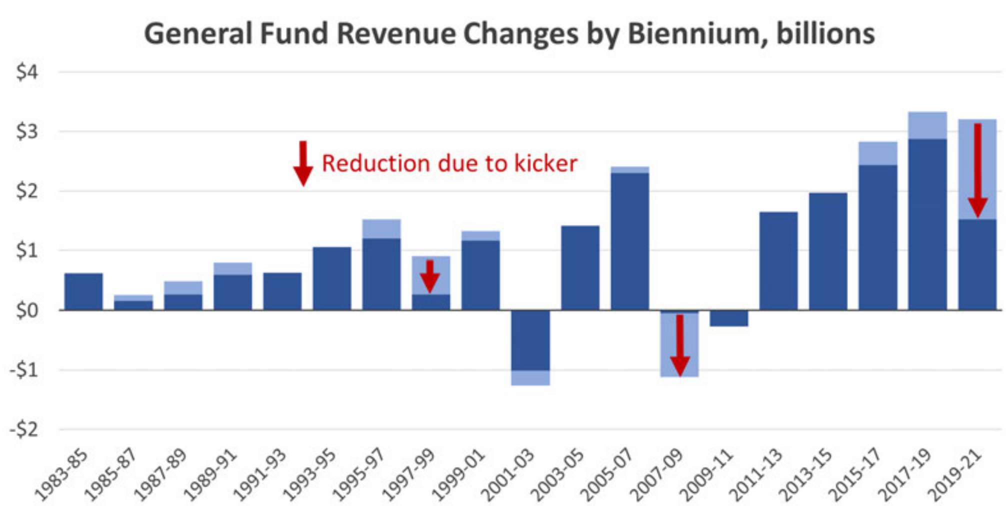
Changes to tax law were relatively small in the 2021 session, with a net revenue impact of -$3.6 million to General Fund resources in the 2021-23 budget period. Personal income tax collections will be reduced by an estimated $38.9 million due to tax law changes. Appendix table B.1b details the Close of Session revenue changes for the current biennium.

The September forecast also reveals where revenues landed in the prior budget period. In a typical year, there are few surprises, since tax collections are relatively small during the early summer. This year was different. Due to a delayed tax filing deadline, much uncertainty remained following the May forecast. When the forecast was developed, the peak tax season had just begun.

By the end of the fiscal year, the 2021 tax season turned out to be a very big one. Collections of personal income taxes, corporate income taxes, lottery sales and the new Corporate Activity Tax all surged at the end of the fiscal year.

As has been discussed earlier, the current business cycle is unique in that household income has risen significantly despite the fact that there are tens of thousands fewer jobs in Oregon than there were before the pandemic began. Given that Oregon is an income tax state, growth in tax collections has been robust. Recent withholdings of personal income taxes are up 17% relative to last year. Payments during the tax season were strong as well, led by collections from high-income taxpayers.

The strong revenue growth seen during the 2019-21 biennium put a cap on a decade of unprecedented expansion in Oregon's General Fund revenues. Over the past decade, General Fund revenues have almost doubled from around $12 billion per year to around $24 billion. Over the decade as a whole, kicker payments amounted to $2.6 billion, reducing cumulative General Fund resources by 2.6%. Last biennium, kicker payments took away half of the General Fund growth. A $1.9 billion kicker credit is slated for the 2021 tax year as well.



2019-21 General Fund Revenues

Gross General Fund revenues for the 2021-23 biennium are expected to reach $23,424 million. This represents an increase of $95 million from the May 2021 forecast, and an increase of $99 million relative to the Close of Session forecast. Most major General Fund revenue sources have outperformed expectations in recent months, but the outlook going forward is stable. Among non-General Fund sources, revenues tied to consumer spending including lottery sales and the new Corporate Activity Tax finished the year stronger than expected.

Table R.1

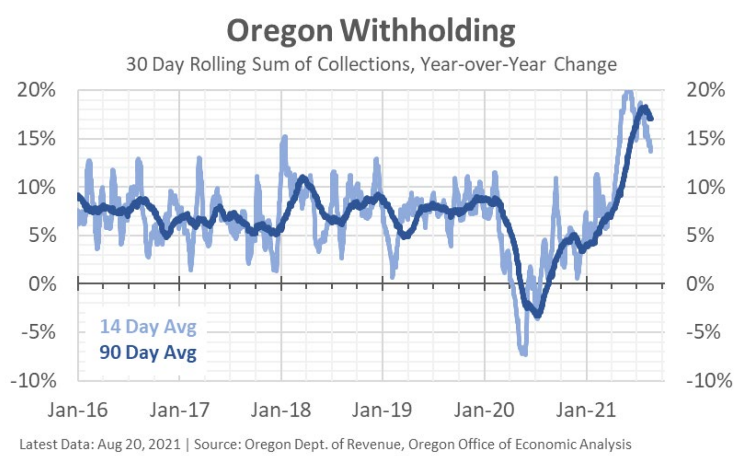
2021-23 General Fund Forecast Summary

(Millions)	2021 COS Forecast	May 2021 Forecast	September 2021 Forecast	Change from Prior Forecast	Change from COS Forecast
Structural Revenues					
Personal Income Tax	$20,628.1	$20,667.9	$20,657.0	-$10.8	$29.0
Corporate Income Tax	$1,344.0	$1,346.2	$1,410.0	$63.8	$66.0
All Other Revenues	$1,353.5	$1,315.0	$1,357.4	$42.3	$3.9
Gross GF Revenues	$23,325.5	$23,329.1	$23,424.4	$95.3	$98.9
Offsets and Transfers	-$171.5	-$171.5	-$174.2	-$2.7	-$2.7
Administrative Actions[1]	-$21.5	$0.0	-$21.5	-$21.5	$0.0
Legislative Actions	-$224.6	-$226.4	-$224.6	$1.8	$0.0
Net Available Resources	$26,008.4	$25,830.6	$26,783.3	$952.7	$774.9
Confidence Intervals					
67% Confidence	+/- 8.6%		$2,014.7	$21.41B to $25.44B	
95% Confidence	+/- 17.2%		$4,029.4	$19.39B to $27.45B	

1 Reflects cost of cashflow management actions, exclusive of internal borrowing.

Personal Income Tax

Personal income tax collections have far outstripped expectations since the May 2021 forecast. Strong personal income tax collections have come from a range of sources, including a boom in withholdings. Personal income tax withholdings are driven primarily by wages and salaries in the labor market. Along with strong growth in employment and wages, withholdings are expanding at a double-digit rate. In addition to larger paychecks, growth in retirement income and the expanded unemployment insurance benefits have also supported withholdings.

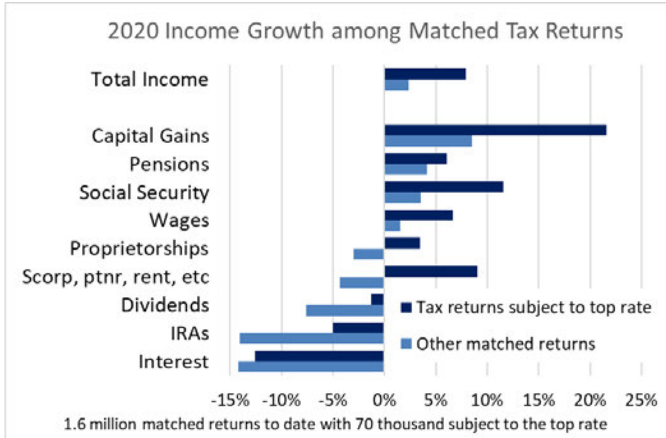


Due to a delayed filing deadline, year-end payments arrived late. Although late, when payments did arrive, they were unexpectedly large. Income from capital gains was a significant factor.

Business income of all types was also surprisingly robust. Given that tax returns reflect the 2020 tax year, large losses of business income were expected. Industries such as leisure/hospitality and education were hit hard by shutdowns and other pandemic-related demand shocks. Also, losses in rental income were expected given eviction moratoriums, and the lack of demand for office space and brick-and-mortar retail. Finally, expenditures made using forgiven PPP loans are considered deductible, reducing business income by as much as $10 billion. Despite all of these negative factors, taxable business income was stable in 2020.

Some of the recent strength of business and investment income can be traced to tax management strategies. In particular, many taxpayers tried to realize additional income in tax year 2020 in anticipation of tax increases at the federal level. Plans have included unwinding some of the corporate and business tax cuts included in the Tax Cuts and Jobs Act, as well as an increase in the tax rate on capital gains.

Looking at tax returns for taxpayers who filed in both tax year 2019 and tax year 2020 helps to highlight recent income gains. However, this represents an incomplete sample since there are still many returns yet to be processed. These outstanding tax returns include many of the highest-income households that file extensions in the fall.



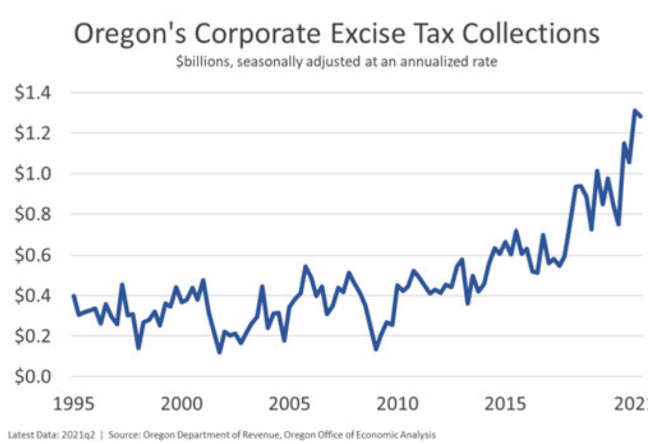
In the available sample, high-income filers have exhibited much stronger income growth than have other taxpayers across every major income stream. Taxpayers subject to Oregon's top tax rate have reported income gains of 8.0% in 2020, while all other taxpayers have reported only 2.4% more income than last year. Although the average tax return has posted some growth, disparities widened further in 2020, with high-income households pulling further away.

Income Group	Adjusted Gross Income*	Rough Estimate of Kicker Size**
Bottom 20%	< $12,100	$30
Second 20%	$12,100 - $29,300	$200
Middle 20%	$29,300 - $52,100	$440
Fourth 20%	$52,100 - $95,000	$790
Next 15%	$95,000 - $195,600	$1,600
Next 4%	$195,600 - $442,700	$3,780
Top 1%	> $442,700	$16,880
Average	**$67,500**	**$850**
Median	**$35,000-$40,000**	**$420**

The robust growth in personal income taxes and other General Fund sources has resulted in an increase in the kicker credit for 2021. The credit now stands at $1.9 billion. The kicker credit is allocated based on 2020 personal tax liability. As such, it is distributed the same as overall tax payments, which are much larger for high-income filers than for other taxpayers. Preliminary estimates suggest that the median 2021 credit will be $420, while the average credit will be $850.

Corporate Excise Tax

Corporate excise tax collections have yet to weaken at all. After a temporary drop at the beginning of the recession, corporate tax collections immediately bounced back and continue to set new records. This stands in stark contrast to the last two recessions when corporate tax collections were cut in half. In fiscal year 2021, corporate collections rose by 44%. When return data becomes available, it will be interesting to see if some of this growth has been fueled by new corporations. The number of C-corporations filing Oregon tax returns has been stuck around 30,000 for several years.



The strong performance of corporate taxes is particularly surprising given that they were expected to come back down to earth even before the recession began. The subtraction for taxes paid under Oregon's new Corporate Activity Tax is also reducing traditional liability. Even so, collections have doubled over the last two budget periods.

While some of this increase likely reflects a permanent increase in the tax base, a significant amount of the growth is expected to be temporary. As with business and investment income on personal tax returns, corporate taxpayers are pulling income forward in advance of possible federal tax legislation.

Record growth in corporate tax collections has led to an $847 million corporate kicker dedicated to K-12 education. Although there is a very long way to go, a $67 million kicker is estimated for the next biennium.

Other Sources of Revenue

Non-personal and non-corporate revenues in the General Fund usually account for approximately 6 or 7 percent of the total. The largest such source are estate taxes, followed by liquor revenues, and judicial revenues.

Legislation during the 2021 session raised these revenue sources a combined $38.4 million, largely due to budget rebalancing from the 2019-21 biennium and a delay in the implementation of the state's Paid Family and Medical Leave program, which results in a one-time payback of funds to the General Fund. Absent those, legislation reduced the General Fund portion of judicial revenues by $5.9 million, liquor revenues by $15.8 million, and increased Secretary of State fees by $1.5 million.

Relative to the Close of Session forecast, the current outlook for 2021-23 is raised by $3.9 million (+0.3%), driven by an increase in Insurance Taxes (+$4.1 million). The outer biennia are lowered slightly as the reductions in judicial revenues carry forward into the future.

One topic to continue to track are tobacco sales following the passage of Measure 108 at the ballot box last year. To date actual revenues are very close to initial expectations through the first six months under the new taxing regime. Cigarette revenue is coming in approximately $2 million above forecast, while Other Tobacco Products (mostly moist snuff) is approximately $1 million below forecast so far. The largest discrepancy to date is related to Inhalant Delivery Devices which are more than $5 million above expectations. Based on available information, much of this strength was seen in the first quarterly tax return of the year and not the second quarter. As such it is likely that the revenue represents the initial inventory brought into the system and not fundamentally stronger sales than anticipated. However, this will be a revenue stream to closely monitor moving forward. It was not previously taxed, and learning how much of these products Oregonians use will be considerably important in the years ahead as our office forecasts the revenue. See Table B.6 in Appendix B for the full details on tobacco revenues and distributions.

One main reason tobacco sales are important to track is that historically the border tax effect between Oregon and Washington has been very real. Measure 108 raised Oregon's cigarette taxes to $3.33 per pack which are now higher than Washington's at $3.03 per pack, leaving to the side the impact of Washington's retail sales tax. The relative price changes when each state adjusts tax policy have driven short-term tobacco sales trends in each state as well. If historical patterns hold, expectations are that sales in Oregon will drop noticeably this year, while they will likely hold steady, or at least decline more slowly in Washington.

Extended General Fund Outlook

Table R.2 exhibits the long-run forecast for General Fund revenues through the 2029-31 biennium. Users should note that the potential for error in the forecast increases substantially the further ahead we look.

Table R.2

General Fund Revenue Forecast Summary (Millions of Dollars, Current Law)

Revenue Source	Forecast 2019-21 Biennium	% Chg	Forecast 2021-23 Biennium	% Chg	Forecast 2023-25 Biennium	% Chg	Forecast 2025-27 Biennium	% Chg	Forecast 2027-29 Biennium	% Chg	Forecast 2029-31 Biennium	% Chg
Personal Income Taxes	20,047.0	6.5%	20,657.0	3.0%	24,408.9	18.2%	26,596.6	9.0%	29,610.9	11.3%	33,216.3	12.2%
Corporate Income Taxes	2,041.4	16.5%	1,410.0	-30.9%	1,622.4	15.1%	2,004.4	23.5%	2,228.0	11.2%	2,497.9	12.1%
All Others	1,681.1	25.5%	1,432.3	-14.8%	1,433.8	0.1%	1,505.1	5.0%	1,613.5	7.2%	1,686.8	4.5%
Gross General Fund	23,769.5	8.5%	23,499.3	-1.1%	27,465.1	16.9%	30,106.2	9.6%	33,452.4	11.1%	37,401.1	11.8%
Offsets and Transfers	*(114.8)*		*(174.2)*		*(106.7)*		*(83.4)*		*(92.7)*		*(103.9)*	
Net Revenue	23,654.7	8.6%	23,325.0	-1.4%	27,358.5	17.3%	30,022.8	9.7%	33,359.7	11.1%	37,297.2	11.8%

Revenue growth in Oregon and other states will face considerable downward pressure over the 10-year extended forecast horizon. As the baby boom population cohort works less and spends less, traditional state tax instruments such as personal income taxes and general sales taxes will become less effective, and revenue growth will fail to match the pace seen in the past.

Tax Law Assumptions

The revenue forecast is based on existing law, including measures and actions signed into law during the 2021 Oregon Legislative Session. OEA makes routine adjustments to the forecast to account for legislative and other actions not factored into the personal and corporate income tax models. These adjustments can include expected kicker refunds, when applicable, as well as any tax law changes not yet present in the historical data. A summary of actions taken during the 2021 Legislative Session can be found in Appendix B Table B.3. For a detailed treatment of the components of the 2021 Legislatively Enacted Budget, see:

Legislative Fiscal Office's [2021-23 Budget Summary]

Although based on current law, many of the tax policies that impact the revenue forecast are not set in stone. In particular, sunset dates for many large tax credits have been scheduled. As credits are allowed to disappear, considerable support is lent to the revenue outlook in the outer years of the forecast. To the extent that tax credits are extended and not allowed to expire when their sunset dates arrive, the outlook for revenue growth will be reduced. The current forecast relies on estimates taken from the Oregon Department of Revenue's 2021-23 Tax Expenditure Report together with more timely updates produced by the Legislative Revenue Office.

Corporate Activity Tax

HB 3427 (2019) created a new state revenue source by implementing a corporate activity tax (CAT) that went into effect January 2020. Collections for 2019-21 totaled $1,374.9 million, which is somewhat higher that the May forecast due to stronger estimated payments in the second quarter. The forecast for the current biennium is $2,376.8 million, only slightly above the prior forecast.

These revenues are dedicated to spending on education. The legislation also included personal income tax rate reductions, reducing General Fund revenues. The net impact of HB 3427 was designed to generate approximately $1 billion per year in new state resources, or $2 billion per biennium.

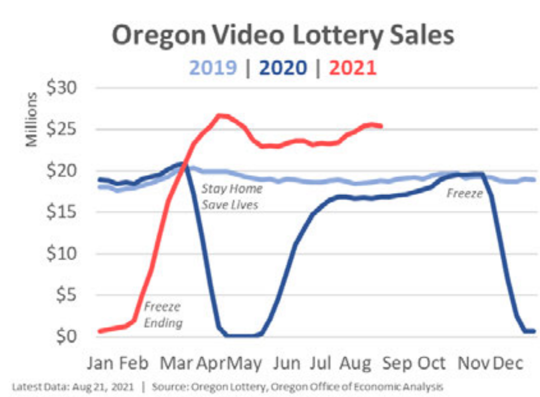
In terms the macroeconomic effects of a major new tax, the Office of Economic Analysis starts with the Legislative Revenue Office's (LRO) impact statement and any Oregon Tax Incidence Model (OTIM) results LRO found. At the top line, OTIM results find minimal macroeconomic impacts across Oregon due to the new tax. Personal income, employment, population, investment and the like are less than one-tenth of a percent different under the new tax relative to the baseline. The model results also show that price levels (inflation) will increase above the baseline as some of the CAT is pushed forward onto consumers. Of course these top line, statewide numbers mask the varying experiences that individual firms and different industries will experience. There are likely to be some businesses or sectors that experience large impacts from the CAT, or where pyramiding increases prices to a larger degree, while other businesses or sectors see relatively few impacts.

Table B.12 in Appendix B has details on 10 year forecast and the allocation of resources, while the personal income tax reductions are built into the General Fund forecasts shown in Tables B.1 and B.2.

Lottery Earnings

Our office continues to use video lottery sales to help inform the overall macroeconomic outlook. Video sales are the best real-time consumer spending data we have in Oregon, and the revenue comes from an indoor activity that is among the most impacted by the pandemic and shutdowns in the past 18 months.

To date video lottery sales are holding strong as the delta wave surges. Household income and savings are up, which allows consumers to spend the money if they want to and feel safe enough doing so. While the OpenTable data indicates the number of seated diners going out to eat in Oregon has softened over the past couple of weeks, any slowdown in video lottery sales is much less pronounced.



The current forecast is raised as a result. Not only has video continued to maintain near record-level sales, this strength is now expected to continue into the fall. Households are still flush. Their accumulated savings is expected to boost spending for months, if not years.

The explicit assumption this forecast makes is video lottery sales will slow in November, and revert back to a steady share of current income. This is for at least three reasons.

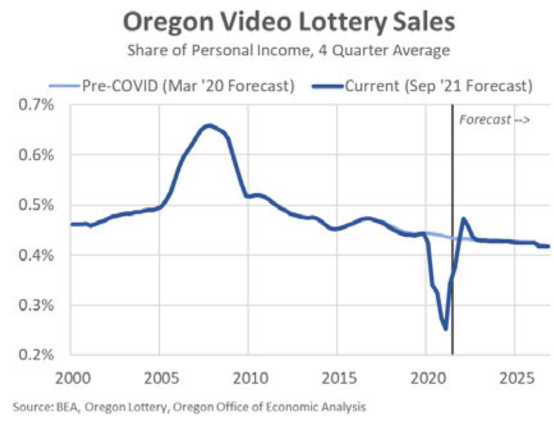
First, the delta wave of the pandemic will wane. Oregonians will continue to move back toward our pre-pandemic lifestyles including going back into the office more frequently and the like. Importantly, other entertainment options like sporting events and concerts will once again compete for households' budgets in greater number. Video lottery faces increased competition as the pandemic wanes.

Second, for most Oregonians their accumulated savings, while impactful, are relatively small. Later this year, many Oregonians' recovery rebates and "excess" unemployment insurance benefits, defined here as greater than 100% wage replacement, will largely be spent down. Rough estimates based on current incomes, the relative size of this savings, and spending patterns suggest this may occur by Thanksgiving. As such our office has video lottery sales slowing in November, even as the exact timing remains an open question and will vary from household to household. After this time, however, consumers will need to rely more on current incomes and less on savings. Video lottery should slow as a result of this process.

Third, sales are also likely to slow from these record levels as pent-up demand is satiated. Total video lottery sales since the start of the pandemic remain about 25 percent below pre-COVID expectations. This has occurred at the same time incomes are 5-10 percent higher than expected. While weekly sales this year are setting records, they have not fully offset the impacts of the two shutdown periods in Oregon when sales were nonexistent. As such, households likely have some continued pent-up demand for gaming, but at some point this should dissipate.

All told the lottery outlook in the current 2021-23 biennium is raised by $48.5 million (+2.9%). Given the biennium just started, this is a substantial increase. The risks are likely to upside as well, depending upon just how long sales stay at their strong levels. To the downside, the risks primarily lie with any potential shutdowns or more stringent health policies. As has been the case twice so far during the pandemic, when bars and restaurants are takeout only, the Oregon Lottery shuts down the video lottery terminals in geographies affected by the shutdowns, and sales go to $0. Should any shutdown be put in place due the pandemic, video lottery sales would decline overnight. Our office's revenue outlook would adjust accordingly.

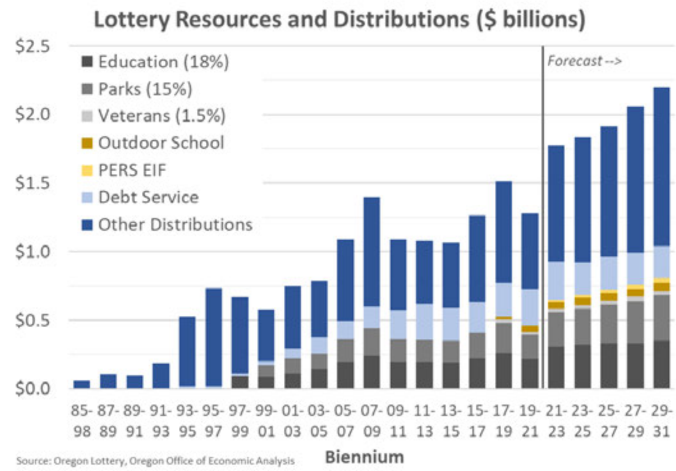
Over the longer-run the video lottery outlook is raised by 0.6 – 0.8 percent, keeping in line with the slightly stronger personal income outlook. Available resources in each biennia, from 2023-25 to 2027-29 are increased by $12-15 million.



That said, there remains upside risks in the years ahead. It is possible that consumers have permanently altered their behaviors and how they spend their household budgets. For now our office is keeping the video lottery sales outlook closely tied to our personal income and consumer spending forecasts. However, if consumers do spend a somewhat larger share of their budget on lottery in the years ahead, it would translate into considerably more state resources. That said, the past 18 months that have upended our lives in many ways are unlikely to be a good barometer of where we end up after the pandemic is managed and brought under control.

Lottery Outlook and Distributions

Big picture issues to watch include broader national trends in gaming markets, demographic preferences for recreational activities, and to what extent consumers decrease the share of their incomes spent on gaming. Up until the past couple of years, consumers had remained cautious with their disposable income. Increases in spending on gaming had largely matched income growth.



Over the long run our office expects increased competition for household entertainment dollars, increased competition within the gaming industry, and potentially shifts in generational preferences and tastes when it comes to gaming. As such, our outlook for video lottery sales is continued growth, however at a rate that is slightly slower than overall personal income growth. Lottery sales will continue to increase as Oregon's population and economy grows, however video lottery sales will likely be a slightly smaller slice of the overall pie.

The full extended outlook for lottery earnings can be found in Table B.9 in Appendix B.

Budgetary Reserves

The state currently administers two general reserve accounts, the Oregon Rainy Day Fund[6] (ORDF) and the Education Stability Fund[7] (ESF). This section updates balances and recalculates the outlook for these funds based on the September revenue forecast.

As of this forecast the two reserve funds currently total a combined $1.41 billion. At the end of the current 2021-23 biennium, they will total $1.95 billion. Including the currently projected $1.33 billion ending balance in the General Fund, the total effective reserves at the end of the current 2021-23 biennium are projected to be $3.28 billion, of nearly 14% of current revenues.

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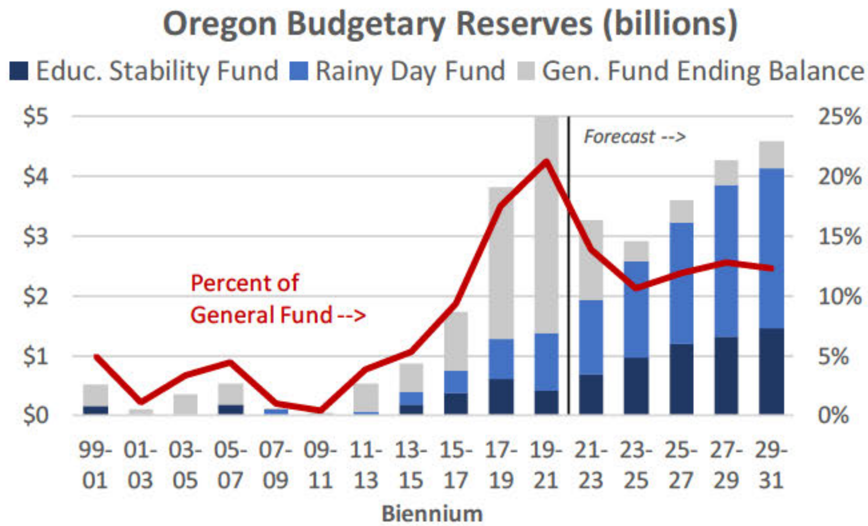
[6] The ORDF is funded from ending balances each biennium, up to one percent of appropriations. The Legislature can deposit additional funds, as it did in first populating the ORDF with surplus corporate income tax revenues from the 2005-07 biennium. The ORDF also retains interest earnings. Withdrawals from the ORDF require one of three triggers, including a decline in employment, a projected budgetary shortfall, or declaration of a state of emergency, plus a three-fifths vote. Withdrawals are capped at two-thirds of the balance as of the beginning of the biennium in question. Fund balances are capped at 7.5 percent of General Fund revenues in the prior biennium.

[7] The ESF gained its current reserve structure and mechanics via constitutional amendment in 2002. The ESF receives 18 percent of lottery earnings, deposited on a quarterly basis – 10% of which are deposited in the Oregon Growth sub-account. The ESF does not retain interest earnings. The ESF has similar triggers as the ORDF, but does not have the two-thirds cap on withdrawals. The ESF balance is capped at five percent of General Fund revenues collected in the prior biennium.



Source: Oregon Office of Economic Analysis

Effective Reserves ($ millions

	End 2019-21	*End 2021-23*
ESF	$415	$690
RDF	$962	$1,256
Reserves	$1,377	$1,946
Ending Balance	$3,697	$1,330
Total	**$5,074**	**$3,276**
% of GF	21.3%	13.9%

The forecast for the ORDF includes two deposits for this biennium relating to the General Fund ending balance from the previous biennium (2019-21). A deposit of $224.6 million is expected to be made in early 2022 after the accountants closed the books. Additionally a $58.2 million deposit relating to the increased corporate taxes from Measure 67 is expected at the end of the biennium in June 2023. This exact transfer amount is subject to some revision as corporate filings are processed, however the transfer itself will occur. At the end of 2021-23 the ORDF will total $1.26 billion.

Looking ahead to the 2023-25 biennium, the ORDF is expected to receive two transfers as well. This includes a projected $254.5 million related to the General Fund ending balance from 2021-23, and $67.5 million related to the increase in corporate taxes. The ORDF is not projected to hit its cap of 7.5% of revenues until FY2029.

The ESF will receive and expected $275.4 million in deposits in the current 2021-23 biennium based on the current lottery forecast. At the end of current 2021-23 biennium the ESF will stand at $689.7 million. The ESF is not projected to hit its cap of 5% of revenues until FY2027, when the deposits will then accrue to the Capital Matching Account.

Together, the ORDF and ESF are projected to have a combined balance of $1.95 billion at the close of the 2021-23 biennium, or 8.3 percent of current revenues. At the close of 2023-25 the combined balance will be $2.58 billion, or 9.4 percent of revenues. Such levels of reserve balances are larger than Oregon has been able to accumulate in past cycles, and should help stabilize the budget when the next recession hits.

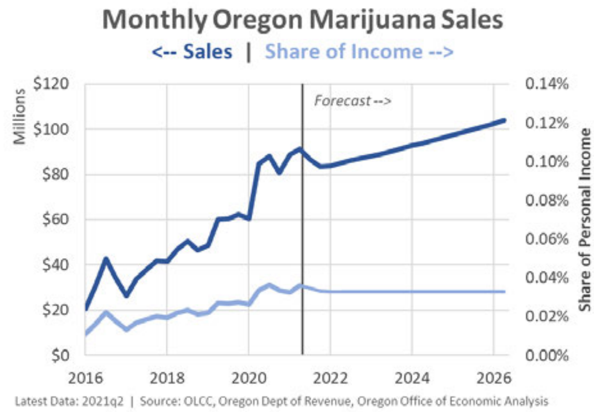
B.10 in Appendix B provides more details for Oregon's budgetary reserves.

Recreational Marijuana Tax Collections

Marijuana sales continue to track the forecast closely. No fundamental changes are made to the outlook, other than updating for the most recent few months of sales.

Looking forward there are three things of note.

In the near-term, sales are expected to slow as the pandemic improves and Oregonians continue to return to their pre-COVID lives. Some of the pandemic-related increase in sales is likely to come off, even as most sticks.



Over the medium- and long-term, sales are expected to increase as Oregon's population, income, and spending grow. However at this point our office does not have a further increase in marijuana usage rates built into the outlook. As such, the risks lie primarily to the upside should usage and broader social acceptance continue to increase. The next National Survey on Drug Use and Health should be released in early 2022 providing an update on usage trends by age and across states in the past year. In consultation with our advisors, should we expect usage rates to increase further in the years ahead, the longer-run forecast would be adjusted accordingly.

The third forecast item of note is a technical but potentially impactful change to the forecast beginning in 2028. Currently medical marijuana is tax exempt. Previous forecasts treated this exemption has permanent and no revenues from medical marijuana were included. What's changed is that during the recently completed legislative session, HB 2433[8] clarified that medical marijuana's tax exemption meets the definition of a tax expenditure. For more on the topic of tax expenditures see this Legislative Revenue Office's report[9].

In Oregon, tax expenditures automatically sunset after six years. In order for them to be extended in the future, the Legislature must act to do so. Our office does what is considered a current law forecast. Given current law now explicitly states medical marijuana's tax exemption sunsets in 2028, our office has raised the long-term marijuana revenue forecast as a result. Whether or not medical marijuana will continue to be exempt after this date will be determined by Legislative action in the years ahead.

See Table B.11 in Appendix B for a full breakdown of revenues, including the newly added medical marijuana revenue, and associated distributions to recipient programs.

[8] https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2433
[9] https://www.oregonlegislature.gov/lro/Documents/HB%202128%20Report%20Final.pdf

POPULATION AND DEMOGRAPHIC OUTLOOK

Population and Demographic Summary

Oregon's resident population count on April 1, 2020 was 4,237,256. This is from the newly released decennial census data administered by the U.S. Census Bureau. During the past decade, Oregon gained 406,182 residents or 10.6 percent. The gain was substantial enough that yielded one additional congressional seat for the state. Oregon will have a total of six members in the House of Representatives. We have been predicting this rare gain. This is rare because only five states gained one additional seat each and Texas gained two seats.

In Historical context, Oregon's population growth between 2010 and 2020 censuses was the second lowest since the first census count in Oregon in 1850. The lowest growth rate was recorded between the 1980 and 1990 censuses, a decade characterized by a major recession. Oregon's population increased by 441 percent in a century. The gain of 406,182 persons in the last decade alone was nearly the same as the total population count of Oregon in the year 1900 when state's population was 403,536. Oregon's population growth of 10.6 percent in the last decade was 11th highest in the nation, excluding Washington D.C. Still, our growth rate for the decade lagged behind all our neighboring states, except California. The prior decade between 2000 and 2010, Oregon's population growth rate ranked 18th highest in the nation when Oregon was hit hard by the double recessions during the decade. As a result of such economic downturn during the Great Recession and sluggish recovery that followed, Oregon's population increased at a slow pace between 2000 and 2010 decade. However, Oregon's population was showing moderately strong growth as a consequence of state's strong economic recovery. The current COVID-19 pandemic has caused dire economic and employment situations and has caused slow population growth. The population growth is expected to rebound after 2021. Based on the current forecast, Oregon's population is expected to reach 4.531 million in the year 2029 with an annual rate of growth of 0.74 percent between 2020 and 2029. The projected population of 2029 is 80,700 less than our March 2020 forecast. The lower projection is due to the lingering COVID-19 effect resulting in higher deaths, lower births, and fewer net-migration, and 2020 Census count coming lower than expected based on the estimates by Population Research Center, Portland State University.

Oregon's economic condition heavily influences the state's population growth. Its economy determines the ability to retain existing work force as well as attract job seekers from national and international labor market. As Oregon's total fertility rate remains well below the replacement level and number of deaths continue to rise due to aging population, long-term growth comes mainly from net in-migration. The COVID-19 pandemic has left noticeable impact on demographic processes. Due to the declining births and rising deaths, we were expecting natural increase (births minus deaths) to turn negative after the year 2025. However, as a COVID effect Oregon's natural increase has already turned negative. Even during this pandemic, Oregon has gained people through net-migration as the worker are able to work from home in many sectors. Working-age adults come to Oregon as long as we have favorable economic conditions and offers better quality of life. During the 1980s, which included a major recession and a net loss of population during the early years, net migration contributed to 22 percent of the population change. On the other extreme, net migration accounted for 76 percent of the population change during the booming economy of early 1990s. This share of migration to population change declined to 32 percent in 2010 as a result of economic recession, lowest since early 1980s when we actually had negative net migration for several years. As a sign of slow to modest economic gain and declining natural increase (births minus deaths), the ratio of net migration-to-population change has registered at 91 percent in 2020. As a result of sudden rise in the number of deaths and fall in the number of births due to the COVID-19 pandemic, the natural increase will turn negative beyond the year 2020 through 2029 and beyond. So, in the future, all of Oregon's population growth and more will come from the net migration due to the combination of continued positive net migration, well below replacement level fertility, and the rise in the number of deaths associated with the increase in the elderly population. Thus, migration will be solely responsible for Oregon's population growth.

Age structure and its change affect employment, state revenue, and expenditure as the demand for services varies by age groups. Demographics are the major budget drivers, which are modified by policy choices on service coverage and delivery. Births, deaths, and migration history of 100 years do impact the current age-sex structure. Growth in many age groups will show the effects of the baby-boom and their echo generations during the forecast period of 2020-2029. It will also reflect demographics impacted by the depression era birth cohort combined with changing migration of working age population and elderly retirees through history. After a period of relatively slow growth during the 1990s and early 2000s, the elderly population (65+) has picked up a faster pace of growth since 2005. This population group will maintain the high growth as the second half of the baby-boom generation continue to enter this age group combined with the attrition of small depression era cohort due to death. This age cohort, however, has hit the plateau of high growth rates exceeding 4 percent annually between 2011 and 2019. The group will experience continued high but diminishing rate of growth. The average annual growth of the elderly population will be 2.5 percent during the 2020-2029 forecast period. Different age groups among the elderly population show quite varied and fascinating growth trends. The youngest elderly (aged 65-74), which has been growing at an extremely fast pace in the recent past averaging 5 percent annually between 2010 and 2020 due to the direct impact of the baby-boom generation entering and smaller pre-baby boom cohort exiting this 65-74 age group. This fast paced growth rate will taper off to negative growth by the end of the forecast period as a sign of the end of the baby-boom generation transitioning to elderly age group. This high growth transitioning into a net loss of this youngest elderly population result in 0.8 percent annual average growth rate in the next nine years. The next older generation of population aged 75-84 has seen reversal of several years of slow growth and a period of shrinking years. The elderly aged 75-84 started to show a positive growth as the effect of depression era birth-cohort has dissipated. An unprecedented fast pace of growth of population in this age group has started as the baby-boom generation is starting to mature from the youngest elderly into this 75-84 age group. Annual growth rate during the forecast period of 2020-2029 is expected to be unusually high 5.3 percent. After a period of slow growth, the oldest elderly (aged 85+) will continue to grow at a strong rate but steadily gaining growth momentum due to the combination of cohort change, continued positive net migration, and improving longevity. The average annual rate of growth for this oldest elderly over the forecast horizon will be 3.3 percent. An unprecedented growth in oldest elderly will commence near the end of the forecast horizon as the fast growing 75-84 age group population transition into this oldest elderly age cohort. As a sign of massive demographic structural change of Oregon's population, starting in 2023 the number of elderly population will exceed the number of children under the age of 18. To illustrate the contrast, in 1980 elderly population numbered less than half of the number of children in Oregon.

The oldest working age population aged 45-64 also has seen the dramatic demographic impact as the baby-boom generation matures out of oldest working-age cohort which is replaced by smaller baby-bust cohort or Gen X. As the effect of this demographic transition combined with slowing net migration, the once fast-paced growth of population aged 45-64 has gradually tapered off to below zero percent rate of growth by 2012 and has remained and will remain at slow or below zero growth phase for several years. The size of this older working-age population will see only a small increase by the end of the forecast period. The younger working-age population of 25-44 age group has recovered from several years of declining and slow growing trend. The decline was mainly due to the exiting baby-boom cohort. This age group has seen positive but slow growth starting in the year 2004 and has gained steam since 2013. This group will increase by 0.9 percent annual average rate during the forecast horizon mainly because of the exiting smaller birth (baby-bust) cohort being replaced by larger baby-boom echo cohort. The young adult population (aged 18-24) will remain nearly unchanged over the forecast period. Although the slow or stagnant growth of college-age population (age 18-24), in general, tend to ease the pressure on public spending on higher education, but college enrollment typically goes up during the time of very competitive job market, high unemployment, and scarcity of well-paying jobs when even the older people flock back to colleges to better position themselves in a tough job market. The growth in K-12 population (aged 5-17) has been very slow or negative in the past and is expected to decline through the forecast years. This will translate into slow growth or even decline in the school enrollments. On average for the forecast period, this school-age population will actually decline by -0.7 percent annually. The growth rate for children under the age of five has remained near or below zero percent in the recent past and will continue to decline due to the sharp decline in the number of births. Although the number of children under the age of five declined in the recent years, the demand for child care services and pre-Kindergarten program will be additionally determined by the labor force participation and poverty rates of the parents.

Overall, elderly population over age 65 will increase rapidly whereas the number of children will actually decline over the forecast horizon. The number of working-age adults in general will show slow growth during the forecast horizon. Hence, based solely on demographics of Oregon, demand for public services geared towards children and young adults will likely to decline or increase only at a slower pace, whereas demand for elderly care and services will increase rapidly.

Procedure and Assumptions

Population forecasts by age and sex are developed using the cohort-component projection procedure. The population by single year of age and sex is projected based on the specific assumptions of vital events and migrations. Oregon's estimated population of July 1, 2020 based on the most recent decennial census is the base for the forecast. To explain the cohort-component projection procedure very briefly, the forecasting model "survives" the initial population distribution by age and sex to the next age-sex category in the following year, and then applies age-sex-specific birth and migration rates to the mid-period population. Further iterations subject the in-and-out migrants to the same mortality and fertility rates.

The U.S. Census Bureau just released apportionment and resident population count of April 1, 2020 for the states. This is the crucial information as the base for all future postcensal population estimates and projections. Also, this 2020 census population is used to determine the error of closure, which is the difference between the actual census enumeration and the estimate based on the previous census of 2010. Again, the error of closure is used to correct and adjust all previous annual postcensal estimates for the time between 2010 and 2020. Since the Bureau has released only the total population, OEA has estimated only the total intercensal population for Oregon based on 2010 and 2020 census counts and postcensal estimates of Population Research Center, Portland State University. Therefore Oregon's intercensal population estimates for the years 2011 through 2020 in this forecast shown in Appendix C are different from prior postcensal numbers. Once the Bureau releases age-sex detail of the census population, OEA will produce readjusted intercensal estimates by age and sex for each of the years from 2011 through 2020. The numbers of births and deaths through 2020 are from Oregon's Center for Health Statistics. All other numbers and age-sex detail are generated by OEA.

Annual numbers of births are determined from the age-specific fertility rates projected based on Oregon's past trends and past and projected national trends. Oregon's total fertility rate is assumed to be 1.4 per woman in 2020 and this rate is projected to remain at similar level through the forecast period which is well below the replacement level of 2.1 children per woman. Oregon’s fertility level is tracking below the national level.

Life Table survival rates are developed for the year 2010 and a new life table for 2020 will be developed when all necessary data becomes available. Male and female life expectancies for the 2010-2029 period are projected based on the past three decades of trends and national projected life expectancies. Gradual improvements in life expectancies are expected over the forecast period. At the same time, the difference between the male and female life expectancies will continue to shrink. The male life expectancy at births of 77.4 and the female life expectancy of 81.8 in 2010 are projected to improve to 79.4 years for males and 83.5 years for females by the year 2029. Life expectancy at birth declined during the current pandemic. However, it is expected to recover after 2021.

Estimates and forecasts of the number of net migrations are based on the residuals from the difference between population change and natural increase (births minus deaths) in a given forecast period. The migration forecasting model uses Oregon’s employment, unemployment rates, income/wage data from Oregon and neighboring states, and past trends. Distribution of migrants by age and sex is based on detailed data from the American Community Survey. In the recent past, slowdown in Oregon’s economy resulted in smaller net migration and slow population growth. Estimated population growth and net migration rates in 2010 and 2011 were the lowest in over two decades. Migration is intrinsically related to economy and employment situation of the state. Still, high unemployment and job loss in the recent past have impacted net migration and population growth, but not to the extent in the early 1980s. Main reason for this is the fact that other states of potential destination for Oregon out-migrants were not faring any better either, limiting the potential destination choices. The role of net migration in Oregon’s population growth will get more prominence as the natural increase has begun to turn negative. The increasing excess of deaths over births will continue due to the rapid increase in the number of deaths associated with the aging population and decline in the number of births largely due to the decline in fertility rate associated with life-style choices. Such a trend was expected, but the COVID-19 has hastened the process. The annual net migration is expected to be low in the short run due to the COVID-19 effect. However, the migration is expected to recover after 2021. Between 2020 and 2029 net migration is expected to be in the range of 16,866 to 38723, averaging 33,450 persons annually.

APPENDIX A: ECONOMIC FORECAST DETAIL

Table A.1 – Employment Forecast Tracking

Total Nonfarm Employment, 2nd quarter 2021
(Employment in thousands, Annualized Percent Change)

	Preliminary Estimate level	Preliminary Estimate % ch	Forecast level	Forecast % ch	Forecast Error level	Forecast Error %	Y/Y Change % ch
Total Nonfarm	1,864.2	11.8	1,848.7	6.6	15.5	0.8	8.3
Total Private	1,583.5	12.6	1,570.4	6.7	13.2	0.8	9.8
Mining and Logging	6.6	(5.0)	6.7	1.8	(0.1)	(2.0)	2.3
Construction	111.1	5.1	110.7	3.4	0.4	0.3	6.5
Manufacturing	185.5	4.1	185.2	2.3	0.3	0.2	2.3
Durable Goods	127.9	3.8	126.6	1.4	1.3	1.0	1.3
Wood Product	22.6	4.2	22.4	8.6	0.2	0.9	5.4
Metals and Machinery	35.4	3.2	35.4	5.8	(0.0)	(0.1)	(2.9)
Computer and Electronic Product	37.9	4.7	37.8	0.1	0.1	0.2	(0.5)
Transportation Equipment	10.8	0.5	10.5	(8.3)	0.4	3.5	5.8
Other Durable Goods	21.2	4.3	20.5	(5.4)	0.7	3.3	5.8
Nondurable Goods	57.6	4.7	58.6	4.2	(1.0)	(1.6)	4.4
Food	28.9	5.8	29.6	5.6	(0.6)	(2.1)	5.7
Other Nondurable Goods	28.7	3.6	29.0	2.8	(0.3)	(1.2)	3.2
Trade, Transportation & Utilities	361.1	0.9	361.7	1.5	(0.6)	(0.2)	9.1
Retail Trade	208.8	0.5	207.3	1.2	1.5	0.7	12.2
Wholesale Trade	74.4	1.9	75.2	2.1	(0.8)	(1.1)	2.4
Transportation, Warehousing & Utilities	77.9	0.9	79.2	1.8	(1.3)	(1.6)	7.8
Information	34.0	10.2	33.5	3.3	0.6	1.6	6.4
Financial Activities	103.0	7.3	103.1	6.2	(0.1)	(0.1)	3.3
Professional & Business Services	250.5	10.1	249.1	8.6	1.4	0.6	7.0
Educational & Health Services	301.7	9.1	300.7	5.5	1.0	0.3	7.3
Educational Services	34.0	43.9	31.7	(6.1)	2.3	7.2	15.4
Health Services	267.7	5.5	269.0	7.0	(1.3)	(0.5)	6.4
Leisure and Hospitality	170.9	88.6	160.6	30.9	10.3	6.4	40.6
Other Services	59.1	16.7	59.1	5.1	0.0	0.1	16.4
Government	280.6	7.3	278.3	5.6	2.3	0.8	0.4
Federal	29.1	5.3	28.0	(7.3)	1.1	3.8	2.1
State	42.8	0.7	42.7	0.7	0.1	0.2	3.9
State Education	0.8	(24.5)	0.9	2.6	(0.1)	(7.7)	(3.5)
Local	208.7	9.0	207.6	8.6	1.2	0.6	(0.5)
Local Education	117.7	15.7	117.9	16.8	(0.2)	(0.2)	(1.4)

Table A.2 – Short-Term Oregon Economic Summary

Oregon Forecast Summary

	Quarterly					Annual					
	2021:2	**2021:3**	**2021:4**	**2022:1**	**2022:2**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
			Personal Income ($ billions)								
Nominal Personal Income	253.3	250.4	252.1	254.8	258.9	224.3	241.5	257.0	260.4	273.7	286.5
% change	(24.9)	(4.5)	2.8	4.4	6.5	4.2	7.6	6.4	1.4	5.1	4.7
Real Personal Income (base year=2012)	221.1	217.2	217.8	219.2	221.7	204.2	217.3	224.2	222.5	229.6	235.8
% change	(29.2)	(6.9)	1.2	2.6	4.6	2.6	6.4	3.2	(0.7)	3.2	2.7
Nominal Wages and Salaries	121.5	123.8	126.0	128.1	130.2	112.5	113.9	122.7	131.2	138.8	145.7
% change	6.6	7.9	7.5	6.5	6.8	5.0	1.3	7.7	6.9	5.8	5.0
			Other Indicators								
Per Capita Income ($1,000)	59.6	58.8	59.1	59.6	60.5	53.3	56.9	60.4	60.8	63.4	65.8
% change	(25.2)	(5.0)	2.2	3.6	5.8	3.2	6.9	6.0	0.7	4.3	3.8
Average Wage rate ($1,000)	64.7	64.7	65.1	65.6	66.3	57.2	62.0	65.0	66.6	69.3	72.0
% change	(4.7)	(0.5)	2.8	3.0	4.1	3.6	8.4	4.8	2.4	4.0	3.9
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.21	4.24	4.26	4.29	4.32	4.35
% change	0.5	0.5	0.6	0.8	0.7	0.9	0.7	0.4	0.7	0.8	0.8
Housing Starts (Thousands)	22.3	20.7	20.3	20.1	20.0	20.7	18.1	20.6	20.3	21.8	22.4
% change	92.1	(25.8)	(8.5)	(2.8)	(2.0)	5.7	(12.4)	13.5	(1.3)	7.3	3.0
Unemployment Rate	5.8	5.6	5.6	5.4	5.3	3.7	7.6	5.8	5.1	4.0	3.9
Point Change	(0.3)	(0.2)	0.0	(0.2)	(0.1)	(0.3)	3.9	(1.8)	(0.7)	(1.1)	(0.1)
			Employment (Thousands)								
Total Nonfarm	1,864.2	1,901.8	1,923.0	1,939.8	1,952.4	1,954.3	1,827.5	1,875.5	1,957.4	1,992.3	2,013.3
% change	11.8	8.3	4.5	3.5	2.6	1.6	(6.5)	2.6	4.4	1.8	1.1
Private Nonfarm	1,583.5	1,605.9	1,622.4	1,638.8	1,651.4	1,655.8	1,542.8	1,587.3	1,655.9	1,689.2	1,708.7
% change	12.6	5.8	4.2	4.1	3.1	1.7	(6.8)	2.9	4.3	2.0	1.2
Construction	111.1	111.7	111.7	111.5	111.4	109.6	108.1	111.0	111.4	111.3	111.8
% change	5.1	2.5	(0.2)	(0.7)	(0.2)	3.9	(1.3)	2.7	0.3	(0.1)	0.4
Manufacturing	185.5	187.0	188.1	189.3	190.4	198.1	185.3	186.1	190.9	194.3	195.1
% change	4.1	3.3	2.4	2.6	2.3	1.5	(6.5)	0.4	2.6	1.8	0.4
Durable Manufacturing	127.9	128.3	128.6	129.1	129.6	137.1	128.3	127.9	129.9	131.9	132.5
% change	3.8	1.4	0.8	1.6	1.4	1.1	(6.4)	(0.3)	1.5	1.6	0.4
Wood Product Manufacturing	22.6	23.0	22.9	23.0	22.9	23.2	22.0	22.7	22.9	22.9	23.0
% change	4.2	6.7	(1.0)	0.4	(0.8)	(1.4)	(5.4)	3.5	0.6	0.1	0.6
High Tech Manufacturing	37.9	37.9	37.9	37.9	38.0	38.6	37.9	37.8	38.0	38.2	38.1
% change	4.7	(0.1)	(0.2)	0.3	0.8	1.8	(1.8)	(0.4)	0.7	0.5	(0.4)
Transportation Equipment	10.8	10.6	10.8	10.9	11.2	12.6	10.9	10.8	11.4	12.2	12.3
% change	0.5	(7.2)	4.5	7.2	11.9	3.8	(13.2)	(1.6)	6.1	7.2	0.1
Nondurable Manufacturing	57.6	58.7	59.5	60.2	60.9	61.1	57.1	58.2	61.0	62.3	62.6
% change	4.7	7.5	6.0	4.7	4.3	2.4	(6.5)	2.0	4.9	2.1	0.5
Private nonmanufacturing	1,398.0	1,418.9	1,434.2	1,449.5	1,461.0	1,457.7	1,357.5	1,401.2	1,465.0	1,494.9	1,513.7
% change	13.8	6.1	4.4	4.3	3.2	1.7	(6.9)	3.2	4.6	2.0	1.3
Retail Trade	208.8	208.8	209.3	209.8	209.8	210.0	200.8	208.9	209.9	210.2	210.7
% change	0.5	0.1	0.9	0.9	0.1	(0.6)	(4.4)	4.0	0.5	0.2	0.2
Wholesale Trade	74.4	74.8	75.6	76.1	77.1	76.6	74.3	74.7	77.3	78.6	78.6
% change	1.9	2.4	4.3	2.8	5.0	1.2	(3.0)	0.6	3.4	1.7	0.0
Information	34.0	34.2	34.3	34.4	34.6	35.1	33.2	33.9	34.7	35.1	35.8
% change	10.2	2.1	1.4	0.6	3.0	2.2	(5.3)	2.1	2.1	1.3	2.0
Professional and Business Services	250.5	257.0	258.2	259.9	262.1	254.7	242.7	252.6	263.2	272.8	279.2
% change	10.1	10.7	1.9	2.6	3.4	2.0	(4.7)	4.1	4.2	3.6	2.4
Health Services	267.7	270.6	275.8	277.8	279.6	275.5	264.6	269.5	280.8	286.2	290.0
% change	5.5	4.4	7.9	2.9	2.6	2.4	(3.9)	1.8	4.2	2.0	1.3
Leisure and Hospitality	170.9	176.6	182.5	191.8	196.7	213.9	161.5	169.0	197.6	206.8	211.1
% change	88.6	13.9	14.2	21.8	10.7	1.2	(24.5)	4.6	16.9	4.7	2.1
Government	280.6	295.9	300.7	301.0	301.0	298.4	284.7	288.2	301.5	303.1	304.6
% change	7.3	23.6	6.6	0.5	(0.1)	1.2	(4.6)	1.2	4.6	0.5	0.5

Table A.3 – Oregon Economic Forecast Change

Oregon Forecast Change (Current vs. Last)

	Quarterly					Annual					
	2021:2	2021:3	2021:4	2022:1	2022:2	2019	2020	2021	2022	2023	2024
Personal Income ($ billions)											
Nominal Personal Income	253.3	250.4	252.1	254.8	258.9	224.3	241.5	257.0	260.4	273.7	286.5
% change	0.4	(0.1)	0.6	0.2	0.4	0.0	0.3	(0.2)	0.4	0.6	0.3
Real Personal Income (base year=2012)	221.1	217.2	217.8	219.2	221.7	204.2	217.3	224.2	222.5	229.6	235.8
% change	(0.7)	(1.4)	(0.7)	(1.2)	(1.1)	0.0	0.3	(1.2)	(1.1)	(1.0)	(1.2)
Nominal Wages and Salaries	121.5	123.8	126.0	128.1	130.2	112.5	113.9	122.7	131.2	138.8	145.7
% change	(0.0)	(0.2)	0.1	0.5	0.8	0.0	0.8	(0.3)	0.9	1.1	0.6
Other Indicators											
Per Capita Income ($1,000)	59.6	58.8	59.1	59.6	60.5	53.3	56.9	60.4	60.8	63.4	65.8
% change	0.4	(0.1)	0.6	0.2	0.4	0.0	0.3	(0.2)	0.4	0.6	0.3
Average Wage rate ($1,000)	64.7	64.7	65.1	65.6	66.3	57.2	62.0	65.0	66.6	69.3	72.0
% change	(0.8)	(0.7)	(0.4)	0.1	0.4	0.0	0.7	(0.7)	0.5	1.2	1.6
Population (Millions)	4.25	4.26	4.27	4.3	4.3	4.21	4.24	4.26	4.29	4.32	4.35
% change	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Housing Starts (Thousands)	22.3	20.7	20.3	20.1	20.0	20.7	18.1	20.6	20.3	21.8	22.4
% change	21.3	11.3	7.6	6.5	5.2	(0.2)	(0.2)	13.7	6.8	4.7	1.7
Unemployment Rate	5.8	5.6	5.6	5.4	5.3	3.7	7.6	5.8	5.1	4.0	3.9
Point Change	(0.1)	(0.6)	(0.3)	(0.2)	(0.1)	0.0	0.0	(0.3)	(0.3)	(0.5)	(0.2)
Employment (Thousands)											
Total Nonfarm	1,864.2	1,901.8	1,923.0	1,939.8	1,952.4	1,954.3	1,827.5	1,875.5	1,957.4	1,992.3	2,013.3
% change	0.8	0.4	0.5	0.4	0.4	(0.0)	0.0	0.4	0.4	(0.1)	(0.9)
Private Nonfarm	1,583.5	1,605.9	1,622.4	1,638.8	1,651.4	1,655.8	1,542.8	1,587.3	1,655.9	1,689.2	1,708.7
% change	0.8	0.3	0.4	0.3	0.4	(0.0)	0.0	0.3	0.4	(0.0)	(0.6)
Construction	111.1	111.7	111.7	111.5	111.4	109.6	108.1	111.0	111.4	111.3	111.8
% change	0.3	0.9	1.0	0.8	0.4	(0.0)	0.1	0.6	0.6	0.8	1.0
Manufacturing	185.5	187.0	188.1	189.3	190.4	198.1	185.3	186.1	190.9	194.3	195.1
% change	0.2	(0.0)	(0.3)	(0.2)	(0.1)	(0.0)	(0.0)	(0.1)	0.0	0.6	0.4
Durable Manufacturing	127.9	128.3	128.6	129.1	129.6	137.1	128.3	127.9	129.9	131.9	132.5
% change	1.0	0.4	(0.1)	(0.2)	(0.1)	(0.0)	(0.1)	0.4	0.1	0.9	0.8
Wood Product Manufacturing	22.6	23.0	22.9	23.0	22.9	23.2	22.0	22.7	22.9	22.9	23.0
% change	0.9	0.9	(1.0)	(0.7)	(1.0)	0.0	(0.0)	0.7	(1.0)	(0.9)	(1.2)
High Tech Manufacturing	37.9	37.9	37.9	37.9	38.0	38.6	37.9	37.8	38.0	38.2	38.1
% change	0.2	0.0	(0.3)	(0.8)	(0.6)	0.0	(0.0)	(0.2)	(0.5)	(0.4)	(0.4)
Transportation Equipment	10.8	10.6	10.8	10.9	11.2	12.6	10.9	10.8	11.4	12.2	12.3
% change	3.5	(1.2)	(2.5)	(2.3)	(0.1)	(0.0)	0.0	0.2	1.3	6.7	5.5
Nondurable Manufacturing	57.6	58.7	59.5	60.2	60.9	61.1	57.1	58.2	61.0	62.3	62.6
% change	(1.6)	(0.9)	(0.6)	(0.4)	(0.2)	(0.0)	0.0	(1.2)	(0.2)	(0.2)	(0.4)
Private nonmanufacturing	1,398.0	1,418.9	1,434.2	1,449.5	1,461.0	1,457.7	1,357.5	1,401.2	1,465.0	1,494.9	1,513.7
% change	0.9	0.4	0.5	0.4	0.5	(0.0)	0.1	0.3	0.5	(0.1)	(0.7)
Retail Trade	208.8	208.8	209.3	209.8	209.8	210.0	200.8	208.9	209.9	210.2	210.7
% change	0.7	0.5	0.5	0.5	0.2	0.0	0.1	0.6	0.2	0.3	0.7
Wholesale Trade	74.4	74.8	75.6	76.1	77.1	76.6	74.3	74.7	77.3	78.6	78.6
% change	(1.1)	(1.0)	(0.4)	0.0	0.5	(0.0)	0.1	(0.9)	0.5	0.4	0.2
Information	34.0	34.2	34.3	34.4	34.6	35.1	33.2	33.9	34.7	35.1	35.8
% change	1.6	0.6	(0.5)	(1.5)	(1.4)	(0.0)	0.2	0.5	(1.6)	(1.4)	0.1
Professional and Business Services	250.5	257.0	258.2	259.9	262.1	254.7	242.7	252.6	263.2	272.8	279.2
% change	0.6	0.6	0.6	0.6	0.6	(0.0)	0.1	0.5	0.5	(1.9)	(4.8)
Health Services	267.7	270.6	275.8	277.8	279.6	275.5	264.6	269.5	280.8	286.2	290.0
% change	(0.5)	(0.8)	0.1	0.0	(0.1)	0.0	0.1	(0.3)	(0.2)	(0.9)	(1.3)
Leisure and Hospitality	170.9	176.6	182.5	191.8	196.7	213.9	161.5	169.0	197.6	206.8	211.1
% change	6.4	2.6	1.8	1.3	2.4	0.0	(0.1)	2.1	2.3	2.2	1.9
Government	280.6	295.9	300.7	301.0	301.0	298.4	284.7	288.2	301.5	303.1	304.6
% change	0.8	1.2	1.1	1.0	0.6	(0.0)	0.0	0.9	0.6	(0.8)	(2.5)

Table A.4 – Annual Economic Forecast

Sep 2021 - Personal Income

(Billions of Current Dollars)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Personal Income*												
Oregon	224.3	241.5	257.0	260.4	273.7	286.5	300.7	316.1	332.6	350.1	368.4	387.3
% Ch	4.2	7.6	6.4	1.4	5.1	4.7	4.9	5.1	5.2	5.3	5.2	5.1
U.S.	18,551.5	19,727.9	21,085.1	21,279.4	22,175.4	23,148.9	24,243.9	25,449.6	26,757.8	28,142.3	29,554.3	31,010.6
% Ch	3.9	6.3	6.9	0.9	4.2	4.4	4.7	5.0	5.1	5.2	5.0	4.9
Wage and Salary												
Oregon	112.5	113.9	122.7	131.2	138.8	145.7	152.6	159.6	167.1	175.2	183.5	192.3
% Ch	5.0	1.3	7.7	6.9	5.8	5.0	4.7	4.6	4.7	4.8	4.8	4.8
U.S.	9,309.3	9,370.5	10,227.7	10,877.8	11,416.6	11,925.6	12,458.2	13,041.3	13,680.8	14,357.5	15,045.9	15,762.1
% Ch	4.7	0.7	9.1	6.4	5.0	4.5	4.5	4.7	4.9	4.9	4.8	4.8
Other Labor Income												
Oregon	27.2	27.4	29.3	31.4	33.3	35.1	36.9	38.8	40.7	42.8	45.0	47.2
% Ch	3.7	0.6	7.0	7.2	6.1	5.4	5.2	5.1	5.0	5.0	5.1	5.1
U.S.	1,474.0	1,457.0	1,546.5	1,634.3	1,715.2	1,791.8	1,871.8	1,959.4	2,055.5	2,157.1	2,260.5	2,368.1
% Ch	3.0	(1.2)	6.1	5.7	5.0	4.5	4.5	4.7	4.9	4.9	4.8	4.8
Nonfarm Proprietor's Income												
Oregon	19.5	19.8	22.1	23.2	24.3	25.4	26.9	28.6	30.2	31.7	33.3	35.0
% Ch	4.5	1.5	11.9	4.9	4.6	4.8	5.6	6.4	5.7	5.0	5.0	5.0
U.S.	1,608.0	1,630.5	1,779.1	1,762.1	1,814.1	1,907.1	2,019.5	2,134.6	2,242.1	2,333.9	2,421.4	2,523.5
% Ch	4.2	1.4	9.1	(1.0)	3.0	5.1	5.9	5.7	5.0	4.1	3.7	4.2
Dividend, Interest and Rent												
Oregon	47.2	46.8	47.8	51.2	53.4	55.2	57.3	60.1	63.4	67.1	70.9	74.7
% Ch	1.4	(0.8)	2.1	7.1	4.3	3.3	3.7	4.9	5.6	5.8	5.8	5.3
U.S.	3,755.0	3,714.6	3,795.7	4,055.6	4,213.1	4,355.4	4,534.8	4,760.4	5,025.1	5,320.7	5,627.4	5,929.2
% Ch	1.3	(1.1)	2.2	6.8	3.9	3.4	4.1	5.0	5.6	5.9	5.8	5.4
Transfer Payments												
Oregon	42.4	58.1	61.5	51.6	53.8	56.6	60.0	63.6	67.3	71.3	75.6	79.8
% Ch	5.6	37.0	5.9	(16.2)	4.2	5.3	6.0	5.9	5.8	6.0	5.9	5.7
U.S.	3,078.0	4,221.6	4,464.2	3,730.5	3,836.9	4,026.6	4,256.3	4,493.5	4,741.6	5,010.8	5,288.1	5,569.8
% Ch	5.3	37.2	5.7	(16.4)	2.9	4.9	5.7	5.6	5.5	5.7	5.5	5.3
Contributions for Social Security												
Oregon	19.6	20.1	21.4	22.6	24.1	25.5	26.7	28.0	29.3	30.8	32.3	33.8
% Ch	5.3	2.6	6.3	5.9	6.6	5.7	4.8	4.6	4.8	4.9	4.9	4.8
U.S.	769.7	778.0	847.3	892.5	934.3	974.4	1,017.0	1,064.0	1,115.8	1,170.5	1,226.2	1,284.0
% Ch	4.7	1.1	8.9	5.3	4.7	4.3	4.4	4.6	4.9	4.9	4.8	4.7
Residence Adjustment												
Oregon	(5.3)	(5.3)	(5.7)	(6.1)	(6.4)	(6.7)	(7.0)	(7.3)	(7.7)	(8.0)	(8.4)	(8.8)
% Ch	3.6	0.0	7.1	6.2	5.4	5.0	4.7	4.5	4.5	4.6	4.5	4.6
Farm Proprietor's Income												
Oregon	0.5	0.9	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7
% Ch	38.8	88.2	(32.5)	(1.1)	9.2	6.1	4.5	1.6	0.7	0.7	0.2	0.5
Per Capita Income (Thousands of $)												
Oregon	53.3	56.9	60.4	60.8	63.4	65.8	68.5	71.4	74.5	77.9	81.3	84.8
% Ch	3.2	6.9	6.0	0.7	4.3	3.8	4.1	4.3	4.4	4.5	4.4	4.3
U.S.	56.1	59.5	63.5	63.9	66.3	68.8	71.7	74.9	78.3	81.9	85.6	89.3
% Ch	3.4	6.0	6.7	0.6	3.7	3.9	4.2	4.4	4.6	4.6	4.5	4.4

* Personal Income includes all classes of income minus Contributions for Social Security

Sep 2021 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Nonfarm												
Oregon	1,954.3	1,827.5	1,875.5	1,957.4	1,992.3	2,013.3	2,029.1	2,042.4	2,058.1	2,075.5	2,089.9	2,103.6
% Ch	1.6	(6.5)	2.6	4.4	1.8	1.1	0.8	0.7	0.8	0.8	0.7	0.7
U.S.	150.9	142.3	146.2	151.5	154.1	155.2	155.9	156.8	157.9	159.0	159.8	160.6
% Ch	1.3	(5.7)	2.8	3.7	1.7	0.7	0.5	0.6	0.7	0.7	0.5	0.5
Private Nonfarm												
Oregon	1,655.8	1,542.8	1,587.3	1,655.9	1,689.2	1,708.7	1,723.2	1,735.1	1,749.3	1,765.1	1,778.3	1,790.1
% Ch	1.7	(6.8)	2.9	4.3	2.0	1.2	0.8	0.7	0.8	0.9	0.7	0.7
U.S.	128.3	120.3	124.3	129.0	131.2	132.2	132.8	133.6	134.5	135.6	136.3	136.9
% Ch	1.5	(6.2)	3.3	3.7	1.7	0.7	0.5	0.6	0.7	0.7	0.6	0.4
Mining and Logging												
Oregon	6.9	6.6	6.7	6.7	6.7	6.8	6.9	6.9	7.0	7.0	7.0	7.0
% Ch	(4.4)	(4.7)	1.8	0.4	(0.4)	1.0	1.3	1.1	0.7	0.2	0.2	0.2
U.S.	0.7	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
% Ch	0.0	(14.7)	1.7	5.5	0.8	1.0	0.8	0.5	0.4	0.9	1.4	1.5
Construction												
Oregon	109.6	108.1	111.0	111.4	111.3	111.8	112.3	112.8	113.4	113.9	114.4	114.9
% Ch	3.9	(1.3)	2.7	0.3	(0.1)	0.4	0.5	0.4	0.5	0.4	0.4	0.4
U.S.	7.5	7.3	7.4	7.4	7.4	7.4	7.5	7.6	7.6	7.7	7.8	7.9
% Ch	2.8	(2.9)	1.9	0.1	(0.3)	0.1	0.8	1.1	1.1	1.0	1.0	0.9
Manufacturing												
Oregon	198.1	185.3	186.1	190.9	194.3	195.1	194.9	194.6	194.7	195.3	195.8	195.9
% Ch	1.5	(6.5)	0.4	2.6	1.8	0.4	(0.1)	(0.1)	0.1	0.3	0.2	0.1
U.S.	12.8	12.2	12.3	12.5	12.6	12.5	12.3	12.2	12.2	12.2	12.1	12.1
% Ch	1.0	(4.9)	1.3	1.6	0.3	(0.9)	(1.2)	(0.9)	(0.3)	(0.1)	(0.3)	(0.5)
Durable Manufacturing												
Oregon	137.1	128.3	127.9	129.9	131.9	132.5	132.3	131.6	131.5	131.7	131.8	131.8
% Ch	1.1	(6.4)	(0.3)	1.5	1.6	0.4	(0.2)	(0.5)	(0.1)	0.1	0.1	(0.0)
U.S.	8.0	7.6	7.7	7.9	7.9	7.8	7.7	7.6	7.6	7.6	7.6	7.5
% Ch	1.2	(5.7)	1.3	2.3	0.6	(1.3)	(1.5)	(1.1)	(0.2)	0.1	(0.1)	(0.5)
Wood Products												
Oregon	23.2	22.0	22.7	22.9	22.9	23.0	23.1	23.1	23.2	23.3	23.4	23.4
% Ch	(1.4)	(5.4)	3.5	0.6	0.1	0.6	0.1	0.2	0.3	0.6	0.4	0.1
U.S.	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
% Ch	0.7	(3.3)	3.3	1.0	(6.0)	(0.8)	0.1	(4.5)	(3.5)	0.9	1.7	1.0
Metal and Machinery												
Oregon	40.2	36.6	35.4	36.0	36.5	37.0	37.3	37.4	37.4	37.4	37.4	37.4
% Ch	2.2	(9.1)	(3.1)	1.5	1.6	1.2	1.0	0.3	0.0	(0.2)	0.0	0.1
U.S.	3.0	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
% Ch	1.1	(6.3)	1.0	3.0	0.9	(0.9)	(1.2)	(0.5)	0.1	0.2	0.1	(0.3)
Computer and Electronic Products												
Oregon	38.6	37.9	37.8	38.0	38.2	38.1	37.7	37.5	37.3	37.3	37.2	37.2
% Ch	1.8	(1.8)	(0.4)	0.7	0.5	(0.4)	(0.9)	(0.6)	(0.4)	(0.2)	(0.1)	(0.1)
U.S.	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0
% Ch	2.0	(0.3)	0.9	(0.2)	(0.1)	0.7	0.3	(0.4)	(0.6)	(1.1)	(1.2)	(1.1)
Transportation Equipment												
Oregon	12.6	10.9	10.8	11.4	12.2	12.3	12.1	12.0	12.0	12.0	11.9	11.8
% Ch	3.8	(13.2)	(1.6)	6.1	7.2	0.1	(1.5)	(0.6)	(0.2)	0.1	(0.5)	(1.1)
U.S.	1.7	1.6	1.6	1.7	1.7	1.7	1.6	1.6	1.6	1.6	1.6	1.5
% Ch	1.6	(8.6)	0.6	4.7	3.6	(2.8)	(2.9)	(2.4)	(0.3)	0.0	(1.1)	(1.9)
Other Durables												
Oregon	22.4	20.9	21.2	21.6	22.1	22.2	22.1	21.6	21.6	21.8	21.8	21.9
% Ch	(0.7)	(6.8)	1.5	1.8	2.2	0.5	(0.4)	(2.1)	(0.0)	0.7	0.4	0.4
U.S.	2.2	2.1	2.2	2.2	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1
% Ch	0.6	(5.2)	2.5	0.9	(1.5)	(1.5)	(1.7)	(1.5)	(0.3)	0.8	0.9	0.5
Nondurable Manufacturing												
Oregon	61.1	57.1	58.2	61.0	62.3	62.6	62.6	62.9	63.2	63.6	64.0	64.1
% Ch	2.4	(6.5)	2.0	4.9	2.1	0.5	(0.1)	0.5	0.4	0.6	0.6	0.2
U.S.	4.8	4.6	4.7	4.7	4.7	4.7	4.6	4.6	4.6	4.6	4.5	4.5
% Ch	0.8	(3.7)	1.4	0.6	(0.4)	(0.4)	(0.6)	(0.6)	(0.5)	(0.4)	(0.5)	(0.6)
Food Manufacturing												
Oregon	29.9	28.0	29.2	30.0	30.3	30.4	30.4	30.5	30.6	30.6	30.8	30.9
% Ch	0.1	(6.3)	4.3	2.8	0.8	0.3	0.2	0.3	0.3	0.2	0.5	0.3
U.S.	1.6	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.8	1.8
% Ch	1.5	(1.6)	0.6	(0.9)	1.4	1.6	1.3	1.1	1.2	0.9	0.7	0.6
Other Nondurable												
Oregon	31.2	29.1	29.0	31.0	32.1	32.3	32.2	32.4	32.6	33.0	33.2	33.3
% Ch	4.7	(6.7)	(0.3)	7.0	3.4	0.7	(0.3)	0.8	0.6	1.1	0.7	0.2
U.S.	3.1	3.0	3.0	3.1	3.0	3.0	2.9	2.9	2.9	2.8	2.8	2.7
% Ch	0.4	(4.8)	1.8	1.4	(1.3)	(1.5)	(1.6)	(1.6)	(1.4)	(1.3)	(1.3)	(1.3)
Trade, Transportation, and Utilities												
Oregon	357.2	349.6	361.4	366.1	369.4	370.7	371.8	373.0	374.0	374.7	375.1	375.3
% Ch	1.3	(2.1)	3.4	1.3	0.9	0.3	0.3	0.3	0.3	0.2	0.1	0.1
U.S.	27.7	26.6	27.5	27.4	27.1	26.5	26.3	26.3	26.3	26.2	26.1	26.0
% Ch	0.4	(4.1)	3.3	(0.3)	(1.2)	(2.1)	(0.7)	0.0	(0.2)	(0.3)	(0.4)	(0.4)

Sep 2021 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Retail Trade												
Oregon	210.0	200.8	208.9	209.9	210.2	210.7	211.1	211.4	211.8	212.2	212.4	212.6
% Ch	(0.6)	(4.4)	4.0	0.5	0.2	0.2	0.2	0.1	0.2	0.2	0.1	0.1
U.S.	15.6	14.9	15.5	14.8	14.1	13.5	13.1	12.9	12.8	12.8	12.8	12.7
% Ch	(1.0)	(4.9)	4.0	(4.3)	(4.4)	(4.9)	(2.8)	(1.1)	(0.8)	(0.3)	(0.3)	(0.3)
Wholesale Trade												
Oregon	76.6	74.3	74.7	77.3	78.6	78.6	78.7	79.0	79.3	79.7	80.0	80.2
% Ch	1.2	(3.0)	0.6	3.4	1.7	0.0	0.1	0.4	0.4	0.4	0.4	0.2
U.S.	5.9	5.6	5.7	6.0	6.2	6.3	6.4	6.5	6.5	6.5	6.5	6.4
% Ch	0.8	(4.2)	1.4	5.4	3.5	1.6	1.6	0.9	0.5	(0.4)	(0.5)	(0.6)
Transportation and Warehousing, and Utilities												
Oregon	70.5	74.5	77.8	78.9	80.6	81.4	82.0	82.7	82.9	82.8	82.7	82.5
% Ch	7.4	5.6	4.4	1.4	2.1	1.0	0.7	0.8	0.2	(0.1)	(0.2)	(0.2)
U.S.	6.2	6.1	6.3	6.6	6.7	6.7	6.8	6.9	6.9	6.9	6.9	6.8
% Ch	3.9	(2.0)	3.4	4.4	1.6	0.4	1.4	1.1	0.2	(0.2)	(0.3)	(0.3)
Information												
Oregon	35.1	33.2	33.9	34.7	35.1	35.8	36.0	36.2	36.3	36.5	36.7	36.8
% Ch	2.2	(5.3)	2.1	2.1	1.3	2.0	0.6	0.5	0.5	0.5	0.5	0.4
U.S.	2.9	2.7	2.8	2.9	2.9	3.0	3.0	3.0	3.0	2.9	2.9	2.9
% Ch	0.9	(5.8)	2.0	3.9	2.3	3.1	(0.3)	(1.1)	(0.4)	(0.7)	0.1	0.2
Financial Activities												
Oregon	103.5	101.6	102.8	104.3	104.5	104.9	105.1	104.9	105.1	105.2	105.1	104.6
% Ch	1.3	(1.8)	1.1	1.5	0.2	0.4	0.2	(0.2)	0.1	0.1	(0.1)	(0.4)
U.S.	8.8	8.7	8.8	9.2	9.2	9.2	9.2	9.1	9.0	9.0	8.9	8.9
% Ch	1.9	(0.3)	0.9	4.5	0.4	(0.5)	(0.0)	(0.6)	(1.0)	(0.7)	(0.6)	(0.7)
Professional and Business Services												
Oregon	254.7	242.7	252.6	263.2	272.8	279.2	284.6	289.3	295.4	302.0	307.6	312.9
% Ch	2.0	(4.7)	4.1	4.2	3.6	2.4	1.9	1.7	2.1	2.2	1.9	1.7
U.S.	21.3	20.3	21.0	22.4	23.2	23.6	24.0	24.4	25.0	25.5	25.8	26.0
% Ch	1.6	(4.8)	3.5	7.0	3.4	1.9	1.6	1.7	2.4	2.0	1.1	0.8
Education and Health Services												
Oregon	312.1	296.7	304.0	317.5	323.1	326.9	330.5	333.8	336.8	340.5	343.8	347.0
% Ch	2.2	(4.9)	2.4	4.4	1.8	1.2	1.1	1.0	0.9	1.1	1.0	0.9
U.S.	24.2	23.2	23.6	24.1	24.2	24.5	24.7	24.9	25.1	25.4	25.7	25.9
% Ch	2.2	(3.8)	1.5	2.3	0.3	1.2	0.7	0.9	1.1	1.1	1.0	0.8
Educational Services												
Oregon	36.6	32.1	34.5	36.7	36.9	36.8	36.7	36.6	36.5	36.4	36.2	36.1
% Ch	0.3	(12.3)	7.4	6.5	0.5	(0.1)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
U.S.	3.7	3.5	3.6	3.9	3.9	3.9	3.9	3.9	3.9	4.0	4.0	4.0
% Ch	0.7	(7.6)	2.9	8.6	1.3	0.1	(0.6)	0.1	1.0	1.0	0.5	0.1
Health Care and Social Assistance												
Oregon	275.5	264.6	269.5	280.8	286.2	290.0	293.8	297.2	300.3	304.2	307.5	310.8
% Ch	2.4	(3.9)	1.8	4.2	2.0	1.3	1.3	1.2	1.0	1.3	1.1	1.1
U.S.	20.4	19.8	20.0	20.3	20.3	20.6	20.8	21.0	21.2	21.4	21.7	21.9
% Ch	2.5	(3.1)	1.2	1.1	0.1	1.5	1.0	1.0	1.1	1.1	1.1	0.9
Leisure and Hospitality												
Oregon	213.9	161.5	169.0	197.6	206.8	211.1	213.9	215.7	218.1	221.0	223.5	225.8
% Ch	1.2	(24.5)	4.6	16.9	4.7	2.1	1.3	0.8	1.1	1.3	1.1	1.0
U.S.	16.6	13.4	14.7	16.2	17.6	18.5	18.7	18.8	19.0	19.2	19.5	19.7
% Ch	1.8	(19.4)	9.8	10.1	9.2	4.6	1.4	0.8	0.9	1.2	1.3	1.3
Other Services												
Oregon	64.8	57.4	59.8	63.6	65.2	66.5	67.2	67.8	68.4	68.9	69.4	69.8
% Ch	0.6	(11.3)	4.1	6.3	2.6	2.0	1.1	0.9	0.8	0.8	0.6	0.6
U.S.	5.9	5.4	5.6	6.1	6.3	6.3	6.4	6.5	6.6	6.7	6.8	6.8
% Ch	1.0	(8.4)	4.7	8.7	2.4	0.8	1.4	1.4	1.3	1.3	1.0	0.8
Government												
Oregon	298.4	284.7	288.2	301.5	303.1	304.6	305.9	307.3	308.8	310.3	311.6	313.5
% Ch	1.2	(4.6)	1.2	4.6	0.5	0.5	0.4	0.4	0.5	0.5	0.4	0.6
U.S.	22.6	21.9	21.9	22.6	22.9	23.0	23.1	23.2	23.3	23.4	23.5	23.7
% Ch	0.7	(3.1)	(0.2)	3.3	1.2	0.5	0.5	0.5	0.5	0.5	0.5	0.8
Federal Government												
Oregon	28.5	29.2	28.7	28.4	28.3	28.3	28.3	28.2	28.2	28.2	28.2	28.9
% Ch	1.4	2.4	(1.7)	(1.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	2.8
U.S.	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
% Ch	1.1	3.5	(1.7)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5
State Government, Oregon												
State Total	40.9	41.4	42.8	42.6	42.9	43.5	43.9	44.4	45.0	45.6	46.0	46.4
% Ch	3.6	1.1	3.5	(0.6)	0.7	1.3	1.0	1.1	1.3	1.4	0.9	0.8
State Education	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
% Ch	7.2	4.1	(3.7)	(0.5)	0.6	0.6	0.2	(0.1)	0.1	0.1	0.3	0.0
Local Government, Oregon												
Local Total	229.0	214.2	216.7	230.5	231.9	232.8	233.7	234.6	235.6	236.5	237.4	238.2
% Ch	0.8	(6.5)	1.2	6.4	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.3
Local Education	133.2	121.7	123.8	132.8	132.7	132.3	131.8	131.4	131.0	130.6	130.2	129.7
% Ch	0.3	(8.7)	1.8	7.2	(0.1)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)

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

APPENDIX B: REVENUE FORECAST DETAIL

Table B.1a General Fund Revenue Statement

Table B.1a
General Fund Revenue Statement -- 2019-21

	Estimate at COS 2019	Forecasts Dated: 5/15/2021 2019-20	Forecasts Dated: 5/15/2021 2020-21	Forecasts Dated: 5/15/2021 Total 2019-21	Forecasts Dated: 9/1/2021 2019-20	Forecasts Dated: 9/1/2021 2020-21	Forecasts Dated: 9/1/2021 Total 2019-21	Difference 09/1/2021 Less 5/15/2021	Difference 09/1/2021 Less COS
Taxes									
Personal Income Taxes	18,283,508,000	8,457,914,000	11,031,416,000	19,489,330,000	7,212,170,000	12,834,785,000	20,046,955,000	557,625,000	1,763,447,000
Film and Video and Transfer to Counties	(45,262,000)	(20,122,000)	(20,209,000)	(40,331,000)	(20,122,000)	(20,209,000)	(40,331,000)	0	4,931,000
Corporate Income Taxes	1,190,805,000	835,071,000	1,019,970,000	1,855,041,000	488,294,000	1,553,118,000	2,041,412,000	186,371,000	850,607,000
Transfer to Rainy Day Fund (Minimum Tax)	(158,254,000)	0	(74,659,000)	(74,659,000)	0	(74,500,000)	(74,500,000)	159,000	83,754,000
Insurance Taxes	132,563,000	75,297,000	75,690,000	150,987,000	75,297,000	83,867,000	159,164,000	8,177,000	26,601,000
Estate Taxes	361,189,000	113,796,000	396,183,000	509,979,000	113,796,000	410,270,000	524,066,000	14,087,000	162,877,000
Transfer to PERS UAL	0	0	0	0	0	0	0	0	0
Cigarette Taxes	64,998,000	30,506,000	27,791,000	58,297,000	30,506,000	24,614,000	55,120,000	(3,177,000)	(9,878,000)
Other Tobacco Products Taxes	66,534,000	30,928,000	31,181,000	62,109,000	30,928,000	30,366,000	61,294,000	(815,000)	(5,240,000)
Other Taxes	1,636,000	435,000	893,000	1,328,000	435,000	563,000	998,000	(330,000)	(638,000)
Fines and Fees									
State Court Fees	138,730,000	67,041,000	50,607,000	117,648,000	67,041,000	51,304,000	118,345,000	697,000	(20,385,000)
Secretary of State Fees	70,837,000	39,104,000	40,082,000	79,186,000	39,104,000	42,766,000	81,870,000	2,684,000	11,033,000
Criminal Fines & Assessments	51,748,000	16,411,000	6,072,000	22,483,000	16,411,000	6,929,000	23,340,000	857,000	(28,408,000)
Securities Fees	27,269,000	12,707,000	13,402,000	26,109,000	12,707,000	13,108,000	25,815,000	(294,000)	(1,454,000)
Central Service Charges	10,376,000	5,739,000	5,737,000	11,476,000	5,739,000	5,739,000	11,478,000	2,000	1,102,000
Liquor Apportionment	348,537,000	162,111,000	182,856,000	344,967,000	162,111,000	178,815,000	340,926,000	(4,041,000)	(7,611,000)
Interest Earnings	102,965,000	64,465,000	17,617,000	82,082,000	64,465,000	28,455,000	92,920,000	10,838,000	(10,045,000)
Miscellaneous Revenues	13,500,000	5,565,000	6,000,000	11,565,000	5,565,000	5,933,000	11,498,000	(67,000)	(2,002,000)
One-time Transfers	155,200,000	14,838,000	254,303,000	269,141,000	14,838,000	159,366,542	174,204,542	(94,936,458)	19,004,542
Gross General Fund Revenues	21,020,395,000	9,931,928,000	13,159,800,000	23,091,728,000	8,339,407,000	15,429,998,542	23,769,405,542	677,677,542	2,749,010,542
Total Transfers	(203,516,000)	(20,122,000)	(94,868,000)	(114,990,000)	(20,122,000)	(94,709,000)	(114,831,000)	159,000	88,685,000
Net General Fund Revenues	20,816,879,000	9,911,806,000	13,064,932,000	22,976,738,000	8,319,285,000	15,335,289,542	23,654,574,542	677,836,542	2,837,695,542
Plus Beginning Balance	2,318,444,712			2,709,364,984			2,709,364,984	0	390,920,272
Less Anticipated Administrative Actions*	(21,472,000)			(21,472,000)			0	21,472,000	21,472,000
Less Legislatively Adopted Actions**	(199,459,036)			(198,338,493)			(198,338,493)	0	1,120,543
Available Resources	22,914,392,677			25,466,292,491			26,165,601,033	699,308,542	3,251,208,356
Appropriations	22,409,455,625			22,641,793,514			22,461,278,792	(180,514,722)	51,823,167
Estimated Ending Balance	504,937,052			2,824,498,977			3,704,322,241	879,823,264	3,199,385,189

Table B.1b General Fund Revenue Statement

Table B.1b
General Fund Revenue Statement -- 2021-23 -- Close of Session

	Forecasts Dated: 5/15/2021			Forecasts Dated: Close of Session (COS)			Difference
	2021-22	2022-23	Total 2021-23	2021-22	2022-23	Total 2021-23	COS Less 5/15/2021
Taxes							
Personal Income Taxes	9,762,692,000	10,905,189,000	20,667,881,000	9,757,530,000	10,870,530,000	20,628,060,000	(39,821,000)
Film and Video and Transfer to Counties	(20,280,000)	(20,303,000)	(40,583,000)	(20,280,000)	(20,303,000)	(40,583,000)	0
Corporate Income Taxes	681,242,000	664,942,000	1,346,184,000	680,633,000	663,333,000	1,343,966,000	(2,218,000)
Transfer to Rainy Day Fund (Minimum Tax)	0	(56,001,000)	(56,001,000)	0	(56,001,000)	(56,001,000)	0
Insurance Taxes	68,406,000	66,680,000	135,086,000	68,406,000	66,680,000	135,086,000	0
Estate Taxes	216,265,000	227,583,000	443,848,000	216,265,000	227,583,000	443,848,000	0
Transfer to PERS UAL	0	(74,916,000)	(74,916,000)	0	(74,916,000)	(74,916,000)	0
Cigarette Taxes	22,700,000	22,203,000	44,903,000	22,700,000	22,203,000	44,903,000	0
Other Tobacco Products Taxes	32,465,000	32,664,000	65,129,000	32,465,000	32,664,000	65,129,000	0
Other Taxes	893,000	893,000	1,786,000	893,000	893,000	1,786,000	0
Fines and Fees							
State Court Fees	67,878,000	69,699,000	137,577,000	67,165,000	68,982,000	136,147,000	(1,430,000)
Secretary of State Fees	40,242,000	40,403,000	80,645,000	41,135,000	41,050,000	82,185,000	1,540,000
Criminal Fines & Assessments	15,853,000	15,853,000	31,706,000	13,601,000	13,601,000	27,202,000	(4,504,000)
Securities Fees	13,086,000	13,452,000	26,538,000	13,086,000	13,452,000	26,538,000	0
Central Service Charges	6,373,000	6,373,000	12,746,000	6,373,000	6,373,000	12,746,000	0
Liquor Apportionment	176,774,000	186,212,000	362,986,000	169,419,000	177,718,000	347,137,000	(15,849,000)
Interest Earnings	15,000,000	20,000,000	35,000,000	15,000,000	20,000,000	35,000,000	0
Miscellaneous Revenues	6,000,000	6,000,000	12,000,000	6,000,000	6,000,000	12,000,000	0
One-time Transfers	0	0	0	58,677,000	0	58,677,000	58,677,000
Gross General Fund Revenues	11,125,869,000	12,278,146,000	23,404,015,000	11,169,348,000	12,231,062,000	23,400,410,000	(3,605,000)
Total Transfers	(20,280,000)	(151,220,000)	(171,500,000)	(20,280,000)	(151,220,000)	(171,500,000)	0
Net General Fund Revenues	11,105,589,000	12,126,926,000	23,232,515,000	11,149,068,000	12,079,842,000	23,228,910,000	(3,605,000)
Plus Beginning Balance			2,824,498,977			3,025,585,699	201,086,722
Less Anticipated Administrative Actions*						(21,472,000)	
Less Legislatively Adopted Actions**						(224,612,788)	
Available Resources						26,008,410,911	
Appropriations						25,445,991,039	
Estimated Ending Balance						562,419,872	

Table B.1c General Fund Revenue Statement

Table B.1c
General Fund Revenue Statement -- 2021-23

	Estimate at COS 2021	Forecasts Dated: 5/15/2021 2021-22	Forecasts Dated: 5/15/2021 2022-23	Forecasts Dated: 5/15/2021 Total 2021-23	Forecasts Dated: 9/1/2021 2021-22	Forecasts Dated: 9/1/2021 2022-23	Forecasts Dated: 9/1/2021 Total 2021-23	Difference 09/1/2021 Less 5/15/2021	Difference 09/1/2021 Less COS
Taxes									
Personal Income Taxes	20,628,060,000	9,762,692,000	10,905,189,000	20,667,881,000	9,800,035,000	10,857,002,000	20,657,037,000	(10,844,000)	28,977,000
Film and Video and Transfer to Counties	(40,583,000)	(20,280,000)	(20,303,000)	(40,583,000)	(20,280,000)	(20,803,000)	(41,083,000)	(500,000)	(500,000)
Corporate Income Taxes	1,343,966,000	681,242,000	664,942,000	1,346,184,000	783,581,000	626,377,000	1,409,958,000	63,774,000	65,992,000
Transfer to Rainy Day Fund (Minimum Tax)	(56,001,000)	0	(56,001,000)	(56,001,000)	0	(58,238,000)	(58,238,000)	(2,237,000)	(2,237,000)
Insurance Taxes	135,086,000	68,406,000	66,680,000	135,086,000	69,807,000	69,403,000	139,210,000	4,124,000	4,124,000
Estate Taxes	443,848,000	216,265,000	227,583,000	443,848,000	216,265,000	227,583,000	443,848,000	0	0
Transfer to PERS UAL	(74,916,000)	0	(74,916,000)	(74,916,000)	0	(74,916,000)	(74,916,000)	0	0
Cigarette Taxes	44,903,000	22,700,000	22,203,000	44,903,000	22,502,000	22,203,000	44,705,000	(198,000)	(198,000)
Other Tobacco Products Taxes	65,129,000	32,465,000	32,664,000	65,129,000	32,465,000	32,664,000	65,129,000	0	0
Other Taxes	1,786,000	893,000	893,000	1,786,000	893,000	893,000	1,786,000	0	0
Fines and Fees									
State Court Fees	136,147,000	67,878,000	69,699,000	137,577,000	67,165,000	68,982,000	136,147,000	(1,430,000)	0
Secretary of State Fees	82,185,000	40,242,000	40,403,000	80,645,000	41,135,000	41,050,000	82,185,000	1,540,000	0
Criminal Fines & Assessments	27,202,000	15,853,000	15,853,000	31,706,000	13,976,000	13,876,000	27,852,000	(3,854,000)	650,000
Securities Fees	26,538,000	13,086,000	13,452,000	26,538,000	13,086,000	13,452,000	26,538,000	0	0
Central Service Charges	12,746,000	6,373,000	6,373,000	12,746,000	6,373,000	6,373,000	12,746,000	0	0
Liquor Apportionment	347,137,000	176,774,000	186,212,000	362,986,000	168,764,000	177,703,000	346,467,000	(16,519,000)	(670,000)
Interest Earnings	35,000,000	15,000,000	20,000,000	35,000,000	15,000,000	20,000,000	35,000,000	0	0
Miscellaneous Revenues	12,000,000	6,000,000	6,000,000	12,000,000	6,000,000	6,000,000	12,000,000	0	0
One-time Transfers	58,677,000	0	0	0	58,677,000	0	58,677,000	58,677,000	0
Gross General Fund Revenues	23,400,410,000	11,125,869,000	12,278,146,000	23,404,015,000	11,315,724,000	12,183,561,000	23,499,285,000	95,270,000	98,875,000
Total Transfers	(171,500,000)	(20,280,000)	(151,220,000)	(171,500,000)	(20,280,000)	(153,957,000)	(174,237,000)	(2,737,000)	(2,737,000)
Net General Fund Revenues	23,228,910,000	11,105,589,000	12,126,926,000	23,232,515,000	11,295,444,000	12,029,604,000	23,325,048,000	92,533,000	96,138,000
Plus Beginning Balance	3,025,585,699			2,824,657,977			3,704,322,241	879,823,264	678,736,542
Less Anticipated Administrative Actions*	(21,472,000)			0			(21,472,000)	(21,472,000)	0
Less Legislatively Adopted Actions**	(224,612,788)			(226,417,935)			(224,612,788)	1,805,147	0
Available Resources	26,008,410,911			25,830,755,042			26,783,285,453	952,689,411	774,874,542
Appropriations	25,445,991,039			25,507,870,604			25,445,991,039	(61,722,552)	0
Estimated Ending Balance	562,419,872			322,884,438			1,337,294,414	1,014,411,964	774,874,542

Table B.2 General Fund Revenue Forecast by Fiscal Year

TABLE B.2

General Fund Revenue Forecast

September 2021

($Millions)

Fiscal Years	2019-20 Fiscal Year	2020-21 Fiscal Year	2021-22 Fiscal Year	2022-23 Fiscal Year	2023-24 Fiscal Year	2024-25 Fiscal Year	2025-26 Fiscal Year	2026-27 Fiscal Year	2027-28 Fiscal Year	2028-29 Fiscal Year	2029-30 Fiscal Year	2030-31 Fiscal Year
Taxes												
Personal Income	7,212.2	12,834.8	9,800.0	10,857.0	11,923.8	12,485.1	12,980.8	13,615.8	14,428.8	15,182.1	16,147.6	17,068.7
Film and Video & Transfer to Counties	(20.1)	(20.2)	(20.3)	(20.8)	(21.3)	(17.9)	0.0	0.0	0.0	0.0	0.0	0.0
Corporate Excise & Income	488.3	1,553.1	783.6	626.4	781.9	840.5	953.0	1,051.5	1,083.9	1,144.1	1,214.7	1,283.2
Transfer to RDF & PERS UAL	0.0	(74.5)	0.0	(58.2)	0.0	(67.5)	0.0	(83.4)	0.0	(92.7)	0.0	(103.9)
Insurance	75.3	83.9	69.8	69.4	70.1	71.0	73.7	66.9	84.7	87.4	90.4	93.5
Estate	113.8	410.3	216.3	227.6	234.0	238.9	245.1	250.1	257.7	262.7	267.8	273.0
Transfer to PERS UAL	0.0	0.0	0.0	(74.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cigarette	30.5	24.6	22.5	22.2	22.0	21.5	20.9	20.5	20.1	19.8	19.5	19.2
Other Tobacco Products	30.9	30.4	32.5	32.7	32.7	32.9	32.9	33.1	33.1	33.0	32.9	32.9
Other Taxes	0.4	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Other Revenues												
Licenses and Fees	135.3	114.1	135.4	137.4	136.9	137.7	135.6	135.5	135.4	135.9	136.3	136.6
Charges for Services	5.7	5.7	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Liquor Apportionment	162.1	178.8	168.8	177.7	168.2	176.3	185.1	194.2	203.7	213.5	223.8	234.5
Interest Earnings	64.5	28.5	15.0	20.0	30.0	35.0	40.0	45.0	50.0	50.0	50.0	50.0
Others	20.4	165.4	64.7	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Gross General Fund	8,339.4	15,430.1	11,315.7	12,183.6	13,412.8	14,052.3	14,680.4	15,425.8	16,310.5	17,141.8	18,196.3	19,204.8
Net General Fund	8,319.3	15,335.4	11,295.4	12,029.6	13,391.5	13,967.0	14,680.4	15,342.4	16,310.5	17,049.1	18,196.3	19,100.8

Biennial Totals	2019-21 BN	Change (%)	2021-23 BN	Change (%)	2023-25 BN	Change (%)	2025-27 BN	Change (%)	2027-29 BN	Change (%)	2029-31 BN	Change (%)
Taxes												
Personal Income	20,047.0	6.5%	20,657.0	3.0%	24,408.9	18.2%	26,596.6	9.0%	29,610.9	11.3%	33,216.3	12.2%
Corporate Excise & Income	2,041.4	16.5%	1,410.0	-30.9%	1,622.4	15.1%	2,004.4	23.5%	2,228.0	11.2%	2,497.9	12.1%
Insurance	159.2	-0.7%	139.2	-12.5%	141.1	1.3%	140.6	-0.3%	172.1	22.4%	183.9	6.9%
Estate Taxes	524.1	37.5%	443.8	-15.3%	472.9	6.5%	495.2	4.7%	520.4	5.1%	540.7	3.9%
Cigarette	55.1	-16.0%	44.7	-18.9%	43.5	-2.7%	41.3	-5.0%	39.9	-3.4%	38.7	-3.1%
Other Tobacco Products	61.3	-3.6%	65.1	6.3%	65.6	0.8%	66.0	0.6%	66.1	0.0%	65.8	-0.4%
Other Taxes	1.0	-49.4%	1.8	78.8%	1.8	0.0%	1.8	0.0%	1.8	0.0%	1.8	0.0%
Other Revenues												
Licenses and Fees	249.4	-3.7%	272.7	9.4%	274.6	0.7%	271.1	-1.3%	271.3	0.1%	272.8	0.5%
Charges for Services	11.5	5.5%	12.7	11.0%	12.7	0.0%	12.7	0.0%	12.7	0.0%	12.7	0.0%
Liquor Apportionment	340.9	15.8%	346.5	1.6%	344.5	-0.6%	379.3	10.1%	417.2	10.0%	458.3	9.9%
Interest Earnings	92.9	6.6%	35.0	-62.3%	65.0	85.7%	85.0	30.8%	100.0	17.6%	100.0	0.0%
Others	185.8	1121.7%	70.7	-62.0%	12.0	-83.0%	12.0	0.0%	12.0	0.0%	12.0	0.0%
Gross General Fund	23,769.5	8.5%	23,499.3	-1.1%	27,465.1	16.9%	30,106.2	9.6%	33,452.4	11.1%	37,401.1	11.8%
Net General Fund	23,654.7	8.6%	23,325.0	-1.4%	27,358.5	17.3%	30,022.8	9.7%	33,359.7	11.1%	37,297.2	11.8%

Table B.3 Summary of 2021 Legislative Session Adjustments

	21-23	23-25	25-27	Revenue Impact Statement
Personal Income Tax Impacts (millions)				
Tax Expenditure – HB 2433	-$68.5	-$149.5	-$165.1	HB 2433
EITC (Federal Reconnect) – HB 2457	-$13.0	-$0.4	-$0.4	HB 2457
Pass-Through Entity – SB 139	$41.7	$59.9	$64.2	SB 139
Personal Income Tax Total	**-$39.8**	**-$90.1**	**-$101.4**	
Corporate Income Tax Impacts (millions)				
Tax Expenditure – HB 2433	-$1.0	-$6.5	-$9.7	HB 2433
Broadcasters – SB 136	-$1.2	-$1.2	-$1.2	SB 136
Corporate Income Tax Total	**-$2.2**	**-$7.7**	**-$10.9**	
Other Tax/Revenue Impacts (millions)				
Criminal Fine Account, Traffic - HB 2137	-$0.8	-$0.3	$0.0	HB 2137
Criminal Fine Account, Photo Radar – HB 2530	$0.0	$4.8	$7.5	HB 2530
Criminal Fine Account, Filing Fee – SB 397	-$1.2	-$1.2	-$1.2	SB 397
Criminal Fine Account, Juvenile – SB 817	-$3.0	-$0.9	-$0.9	SB 817
Tax Court - HB 2178	-$0.2	-$0.2	-$0.2	HB 2178
Secretary of State Filing Fees – SB 25	$1.5	-$0.6	-$6.3	SB 25
OLCC, Retail Agents – HB 2740	-$7.6	-$8.0	-$8.4	HB 2740
OLCC, Retail Agents – SB 316	-$1.5	-$2.3	-$2.3	SB 316
Other Tax Total	**-$12.7**	**-$8.6**	**-$11.9**	

Table B.4 Oregon Personal Income Tax Revenue Forecast

TABLE B.4 **OREGON PERSONAL INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted **September 2021**

	2009:3	2009:4	2010:1	2010:2	FY 2010	2010:3	2010:4	2011:1	2011:2	FY 2011
WITHHOLDING	1,092,795	1,151,673	1,157,857	1,116,552	4,518,878	1,146,189	1,196,214	1,262,781	1,218,439	4,823,622
%CHYA	-6.0%	-2.6%	2.6%	2.5%	-1.0%	4.9%	3.9%	9.1%	9.1%	6.7%
EST. PAYMENTS	176,110	161,759	186,894	265,703	790,467	179,692	148,589	207,036	284,662	819,978
%CHYA	-33.4%	-7.5%	-14.0%	1.0%	-14.1%	2.0%	-8.1%	10.8%	7.1%	3.7%
FINAL PAYMENTS	63,363	77,013	105,745	515,262	761,383	62,259	81,728	114,877	607,592	866,456
%CHYA	-9.9%	-22.5%	1.6%	-2.8%	-5.3%	-1.7%	6.1%	8.6%	17.9%	13.8%
REFUNDS	96,477	188,704	459,550	380,459	1,125,190	92,291	151,515	432,478	340,652	1,016,937
%CHYA	4.8%	4.6%	2.6%	-5.9%	0.1%	-4.3%	-19.7%	-5.9%	-10.5%	-9.6%
OTHER	(138,521)	-	-	136,193	(2,328)	(136,193)	-	-	165,933	29,740
TOTAL	1,097,271	1,201,740	990,947	1,653,251	4,943,210	1,159,655	1,275,015	1,152,216	1,935,973	5,522,860
%CHYA	-10.2%	-5.9%	-1.2%	2.3%	-3.4%	5.7%	6.1%	16.3%	17.1%	11.7%

	2011:3	2011:4	2012:1	2012:2	FY 2012	2012:3	2012:4	2013:1	2013:2	FY 2013
WITHHOLDING	1,235,508	1,287,030	1,348,171	1,269,562	5,140,271	1,262,589	1,364,547	1,354,116	1,321,413	5,302,666
%CHYA	7.8%	7.6%	6.8%	4.2%	6.6%	2.2%	6.0%	0.4%	4.1%	3.2%
EST. PAYMENTS	194,674	185,239	199,238	299,646	878,797	205,533	159,104	278,341	321,896	964,874
%CHYA	8.3%	24.7%	-3.8%	5.3%	7.2%	5.6%	-14.1%	39.7%	7.4%	9.8%
FINAL PAYMENTS	85,889	87,233	117,628	627,762	918,512	72,224	91,338	123,456	785,542	1,072,560
%CHYA	38.0%	6.7%	2.4%	3.3%	6.0%	-15.9%	4.7%	5.0%	25.1%	16.8%
REFUNDS	64,687	156,272	530,800	360,618	1,112,377	52,211	109,503	536,506	383,176	1,081,397
%CHYA	-29.9%	3.1%	22.7%	5.9%	9.4%	-19.3%	-29.9%	1.1%	6.3%	-2.8%
OTHER	(165,933)	-	-	193,614	27,681	(193,614)	-	-	201,367	7,753
TOTAL	1,285,451	1,403,230	1,134,237	2,029,966	5,852,884	1,294,521	1,505,486	1,219,407	2,247,042	6,266,457
%CHYA	10.8%	10.1%	-1.6%	4.9%	6.0%	0.7%	7.3%	7.5%	10.7%	7.1%

	2013:3	2013:4	2014:1	2014:2	FY 2014	2014:3	2014:4	2015:1	2015:2	FY 2015
WITHHOLDING	1,333,946	1,435,630	1,442,755	1,420,313	5,632,644	1,455,822	1,523,453	1,576,188	1,505,337	6,060,801
%CHYA	5.7%	5.2%	6.5%	7.5%	6.2%	9.1%	6.1%	9.2%	6.0%	7.6%
EST. PAYMENTS	221,695	214,342	247,826	357,218	1,041,080	264,823	236,303	305,582	408,957	1,215,665
%CHYA	7.9%	34.7%	-11.0%	11.0%	7.9%	19.5%	10.2%	23.3%	14.5%	16.8%
FINAL PAYMENTS	83,096	112,495	139,923	730,795	1,066,309	92,647	144,239	156,188	847,330	1,240,403
%CHYA	15.1%	23.2%	13.3%	-7.0%	-0.6%	11.5%	28.2%	11.6%	15.9%	16.3%
REFUNDS	67,098	197,448	472,018	354,437	1,091,001	100,729	173,522	520,272	375,119	1,169,642
%CHYA	28.5%	80.3%	-12.0%	-7.5%	0.9%	50.1%	-12.1%	10.2%	5.8%	7.2%
OTHER	(201,367)	-	-	180,356	(21,011)	(180,356)	-	-	163,398	(16,959)
TOTAL	1,370,272	1,565,018	1,358,485	2,334,246	6,628,021	1,532,207	1,730,473	1,517,685	2,549,903	7,330,268
%CHYA	5.9%	4.0%	11.4%	3.9%	5.8%	11.8%	10.6%	11.7%	9.2%	10.6%

	2015:3	2015:4	2016:1	2016:2	FY 2016	2016:3	2016:4	2017:1	2017:2	FY 2017
WITHHOLDING	1,551,517	1,644,209	1,711,568	1,634,728	6,542,022	1,675,744	1,705,280	1,835,155	1,769,354	6,985,533
%CHYA	6.6%	7.9%	8.6%	8.6%	7.9%	8.0%	3.7%	7.2%	8.2%	6.8%
EST. PAYMENTS	309,470	141,009	327,008	423,839	1,201,325	300,866	319,225	382,445	450,241	1,452,777
%CHYA	16.9%	-40.3%	7.0%	5.7%	-0.5%	-2.8%	126.4%	17.0%	6.2%	20.9%
FINAL PAYMENTS[1]	99,618	321,345	141,818	813,132	1,375,913	103,631	144,248	175,235	919,186	1,342,301
%CHYA	7.5%	122.8%	-9.2%	-4.9%	10.2%	4.0%	-55.1%	23.6%	13.0%	-2.4%
REFUNDS	85,113	203,981	577,546	562,601	1,429,241	138,825	254,851	574,417	454,899	1,422,992
%CHYA	-15.5%	17.6%	11.0%	50.0%	22.2%	63.1%	24.9%	-0.5%	-19.1%	-0.4%
OTHER	(163,398)	-	-	236,108	72,710	(236,108)	-	-	192,251	(43,856)
TOTAL	1,712,094	1,902,583	1,602,848	2,545,205	7,762,729	1,705,308	1,913,902	1,818,419	2,876,134	8,313,763
%CHYA	11.7%	9.9%	5.6%	-0.2%	5.9%	-0.4%	0.6%	13.4%	13.0%	7.1%

	2017:3	2017:4	2018:1	2018:2	FY 2018	2018:3	2018:4	2019:1	2019:2	FY 2019
WITHHOLDING	1,748,844	1,836,249	2,011,564	1,851,177	7,447,834	1,925,880	2,039,120	2,079,900	1,999,015	8,043,914
%CHYA	4.4%	7.7%	9.6%	4.6%	6.6%	10.1%	11.0%	3.4%	8.0%	8.0%
EST. PAYMENTS	321,032	451,037	464,534	512,671	1,749,274	367,772	284,002	321,858	532,273	1,505,905
%CHYA	6.7%	41.3%	21.5%	13.9%	20.4%	14.6%	-37.0%	-30.7%	3.8%	-13.9%
FINAL PAYMENTS[1]	92,364	169,785	174,096	878,587	1,314,832	104,644	156,592	225,515	1,385,562	1,872,312
%CHYA	-10.9%	17.7%	-0.6%	-4.4%	-2.0%	13.3%	-7.8%	29.5%	57.7%	42.4%
REFUNDS	133,143	266,467	686,100	610,486	1,696,196	140,701	335,635	546,225	445,573	1,468,133
%CHYA	-4.1%	4.6%	19.4%	34.2%	19.2%	5.7%	26.0%	-20.4%	-27.0%	-13.4%
OTHER	(192,251)	-	-	237,300	45,049	(237,300)	-	-	222,477	(14,823)
TOTAL	1,836,845	2,190,604	1,964,094	2,869,249	8,860,793	2,020,295	2,144,078	2,081,049	3,693,754	9,939,176
%CHYA	7.7%	14.5%	8.0%	-0.2%	6.6%	10.0%	-2.1%	6.0%	28.7%	12.2%

Note: "Other" includes July withholding accrued to June.

Tax law impacts are reflected in the collections numbers to produce more meaningful projections.

TABLE B.4 **OREGON PERSONAL INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted **September 2021**

	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
WITHHOLDING	2,059,715	2,223,410	2,183,444	1,997,661	8,464,230	2,127,124	2,291,161	2,321,603	2,266,779	9,006,667
%CHYA	6.9%	9.0%	5.0%	-0.1%	5.2%	3.3%	3.0%	6.3%	13.5%	6.4%
EST. PAYMENTS	413,316	296,072	376,127	428,769	1,514,284	497,544	292,601	432,742	701,877	1,924,764
%CHYA	12.4%	4.3%	16.9%	-19.4%	0.6%	20.4%	-1.2%	15.1%	63.7%	27.1%
FINAL PAYMENTS[1]	131,560	195,074	159,708	330,328	816,671	758,710	142,228	220,765	1,500,229	2,621,931
%CHYA	25.7%	24.6%	-29.2%	-76.2%	-56.4%	476.7%	-27.1%	38.2%	354.2%	221.1%
REFUNDS	144,251	289,464	1,120,326	735,922	2,289,962	432,836	360,529	558,588	672,421	2,024,375
%CHYA	2.5%	-13.8%	105.1%	65.2%	56.0%	200.1%	24.6%	-50.1%	-8.6%	-11.6%
OTHER	(222,477)	-	-	175,167	(47,310)	(175,167)	-	-	194,880	19,713
TOTAL	2,237,864	2,425,092	1,598,954	2,196,004	8,457,914	2,775,375	2,365,460	2,416,522	3,991,345	11,548,702
%CHYA	10.8%	13.1%	-23.2%	-40.5%	-14.9%	24.0%	-2.5%	51.1%	81.8%	36.5%
	2021:3	**2021:4**	**2022:1**	**2022:2**	**FY 2022**	**2022:3**	**2022:4**	**2023:1**	**2023:2**	**FY 2023**
WITHHOLDING	2,285,441	2,372,856	2,468,630	2,357,510	9,484,436	2,343,776	2,476,831	2,542,670	2,423,378	9,786,655
%CHYA	7.4%	3.6%	6.3%	4.0%	5.3%	2.6%	4.4%	3.0%	2.8%	3.2%
EST. PAYMENTS	440,547	299,684	389,838	724,339	1,854,409	351,445	309,275	403,228	760,814	1,824,762
%CHYA	-11.5%	2.4%	-9.9%	3.2%	-3.7%	-20.2%	3.2%	3.4%	5.0%	-1.6%
FINAL PAYMENTS[1]	149,533	225,810	176,745	809,206	1,361,293	107,346	161,175	192,349	1,200,627	1,661,498
%CHYA	-80.3%	58.8%	-19.9%	-46.1%	-48.1%	-28.2%	-28.6%	8.8%	48.4%	22.1%
REFUNDS	231,801	286,730	1,382,428	1,095,567	2,996,526	232,680	528,113	933,762	718,624	2,413,179
%CHYA	-46.4%	-20.5%	147.5%	62.9%	48.0%	0.4%	84.2%	-32.5%	-34.4%	-19.5%
OTHER	(194,880)	-	-	291,303	96,422	(291,303)	-	-	288,568	(2,735)
TOTAL	2,448,839	2,611,621	1,652,785	3,086,790	9,800,035	2,278,585	2,419,168	2,204,485	3,954,764	10,857,002
%CHYA	-11.8%	10.4%	-31.6%	-22.7%	-15.1%	-7.0%	-7.4%	33.4%	28.1%	10.8%
	2023:3	**2023:4**	**2024:1**	**2024:2**	**FY 2024**	**2024:3**	**2024:4**	**2025:1**	**2025:2**	**FY 2025**
WITHHOLDING	2,409,328	2,546,141	2,654,421	2,535,766	10,145,657	2,520,982	2,664,091	2,789,031	2,665,995	10,640,099
%CHYA	2.8%	2.8%	4.4%	4.6%	3.7%	4.6%	4.6%	5.1%	5.1%	4.9%
EST. PAYMENTS	369,143	324,849	424,084	807,137	1,925,213	391,619	344,627	448,594	837,219	2,022,059
%CHYA	5.0%	5.0%	5.2%	6.1%	5.5%	6.1%	6.1%	5.8%	3.7%	5.0%
FINAL PAYMENTS[1]	122,751	195,210	218,279	1,329,097	1,865,337	134,037	212,175	224,312	1,410,823	1,981,347
%CHYA	14.4%	21.1%	13.5%	10.7%	12.3%	9.2%	8.7%	2.8%	6.1%	6.2%
REFUNDS	163,801	356,756	857,876	669,325	2,047,759	162,409	352,481	912,769	720,131	2,147,791
%CHYA	-29.6%	-32.4%	-8.1%	-6.9%	-15.1%	-0.8%	-1.2%	6.4%	7.6%	4.9%
OTHER	(288,568)	-	-	323,908	35,340	(323,908)	-	-	313,316	(10,592)
TOTAL	2,448,853	2,709,445	2,438,908	4,326,582	11,923,788	2,560,320	2,868,412	2,549,168	4,507,223	12,485,122
%CHYA	7.5%	12.0%	10.6%	9.4%	9.8%	4.6%	5.9%	4.5%	4.2%	4.7%
	2025:3	**2025:4**	**2026:1**	**2026:2**	**FY 2026**	**2026:3**	**2026:4**	**2027:1**	**2027:2**	**FY 2027**
WITHHOLDING	2,650,429	2,800,874	2,940,975	2,812,470	11,204,748	2,796,031	2,954,732	3,105,784	2,970,534	11,827,081
%CHYA	5.1%	5.1%	5.4%	5.5%	5.3%	5.5%	5.5%	5.6%	5.6%	5.6%
EST. PAYMENTS	406,215	357,472	465,497	871,089	2,100,273	422,648	371,934	485,201	919,023	2,198,806
%CHYA	3.7%	3.7%	3.8%	4.0%	3.9%	4.0%	4.0%	4.2%	5.5%	4.7%
FINAL PAYMENTS[1]	137,320	221,417	239,715	1,438,883	2,037,336	146,457	231,814	242,902	1,425,911	2,047,083
%CHYA	2.4%	4.4%	6.9%	2.0%	2.8%	6.7%	4.7%	1.3%	-0.9%	0.5%
REFUNDS	167,743	363,716	994,988	786,198	2,312,645	181,606	395,900	1,059,119	836,063	2,472,688
%CHYA	3.3%	3.2%	9.0%	9.2%	7.7%	8.3%	8.8%	6.4%	6.3%	6.9%
OTHER	(313,316)	-	-	264,438	(48,878)	(264,438)	-	-	279,960	15,522
TOTAL	2,712,905	3,016,047	2,651,199	4,600,682	12,980,834	2,919,093	3,162,580	2,774,767	4,759,364	13,615,805
%CHYA	6.0%	5.1%	4.0%	2.1%	4.0%	7.6%	4.9%	4.7%	3.4%	4.9%
	2027:3	**2027:4**	**2028:1**	**2028:2**	**FY 2028**	**2028:3**	**2028:4**	**2029:1**	**2029:2**	**FY 2029**
WITHHOLDING	2,953,164	3,120,781	3,285,361	3,143,001	12,502,307	3,124,613	3,301,955	3,475,339	3,324,638	13,226,545
%CHYA	5.6%	5.6%	5.8%	5.8%	5.7%	5.8%	5.8%	5.8%	5.8%	5.8%
EST. PAYMENTS	445,905	392,400	512,266	974,918	2,325,489	473,025	416,266	543,687	1,038,062	2,471,040
%CHYA	5.5%	5.5%	5.6%	6.1%	5.8%	6.1%	6.1%	6.1%	6.5%	6.3%
FINAL PAYMENTS1	149,036	233,577	250,638	1,487,290	2,120,541	154,408	242,660	261,188	1,567,941	2,226,197
%CHYA	1.8%	0.8%	3.2%	4.3%	3.6%	3.6%	3.9%	4.2%	5.4%	5.0%
REFUNDS	192,784	420,520	1,113,879	878,980	2,606,164	202,854	442,198	1,175,285	927,596	2,747,932
%CHYA	6.2%	6.2%	5.2%	5.1%	5.4%	5.2%	5.2%	5.5%	5.5%	5.4%
OTHER	(279,960)	-	-	366,546	86,586	(366,546)	-	-	372,812	6,265
TOTAL	3,075,362	3,326,238	2,934,387	5,092,774	14,428,761	3,182,646	3,518,684	3,104,929	5,375,856	15,182,115
%CHYA	5.4%	5.2%	5.8%	7.0%	6.0%	3.5%	5.8%	5.8%	5.6%	5.2%

Note: "Other" includes July withholding accrued to June. Tax law impacts are reflected in the collections numbers to produce more meaningful projections.

Table B.5 Oregon Corporate Income Tax Revenue Forecast

TABLE B.5 **OREGON CORPORATE INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted **September 2021**

	2009:3	2009:4	2010:1	2010:2	FY 2010	2010:3	2010:4	2011:1	2011:2	FY 2011
ADVANCE PAYMENTS	79,579	163,877	66,451	147,313	457,220	115,286	175,561	76,405	165,354	532,606
%CHYA	-20.9%	12.8%	4.2%	51.3%	12.3%	44.9%	7.1%	15.0%	12.2%	16.5%
FINAL PAYMENTS	20,404	24,009	38,412	45,714	128,539	21,781	21,206	35,770	40,805	119,562
%CHYA	-13.2%	-10.2%	72.1%	109.5%	36.2%	6.8%	-11.7%	-6.9%	-10.7%	-7.0%
REFUNDS	29,072	137,244	40,080	25,774	232,170	23,130	89,877	39,065	31,489	183,562
%CHYA	3.3%	9.9%	-40.6%	-30.7%	-9.9%	-20.4%	-34.5%	-2.5%	22.2%	-20.9%
TOTAL	70,910	50,642	64,784	167,254	353,589	113,936	106,890	73,111	174,670	468,606
%CHYA	-26.1%	7.3%	247.5%	104.0%	45.1%	60.7%	111.1%	12.9%	4.4%	32.5%

	2011:3	2011:4	2012:1	2012:2	FY 2012	2012:3	2012:4	2013:1	2013:2	FY 2013
ADVANCE PAYMENTS	120,766	154,290	86,873	156,652	518,581	130,348	110,207	80,942	282,526	604,023
%CHYA	4.8%	-12.1%	13.7%	-5.3%	-2.6%	7.9%	-28.6%	-6.8%	80.4%	16.5%
FINAL PAYMENTS	19,117	26,841	32,512	33,322	111,792	16,387	21,377	36,660	34,009	108,433
%CHYA	-12.2%	26.6%	-9.1%	-18.3%	-6.5%	-14.3%	-20.4%	12.8%	2.1%	-3.0%
REFUNDS	34,927	91,252	55,051	18,153	199,384	33,212	17,832	25,595	182,929	259,568
%CHYA	51.0%	1.5%	40.9%	-42.4%	8.6%	-4.9%	-80.5%	-53.5%	907.7%	30.2%
TOTAL	104,955	89,878	64,335	171,820	430,989	113,524	113,751	92,007	133,606	452,888
%CHYA	-7.9%	-15.9%	-12.0%	-1.6%	-8.0%	8.2%	26.6%	43.0%	-22.2%	5.1%

	2013:3	2013:4	2014:1	2014:2	FY 2014	2014:3	2014:4	2015:1	2015:2	FY 2015
ADVANCE PAYMENTS	123,591	187,195	150,401	183,348	644,535	193,248	206,088	106,689	183,611	689,637
%CHYA	-5.2%	69.9%	85.8%	-35.1%	6.7%	56.4%	10.1%	-29.1%	0.1%	7.0%
FINAL PAYMENTS	27,794	18,162	32,218	52,283	130,456	28,815	73,552	57,268	71,415	231,051
%CHYA	69.6%	-15.0%	-12.1%	53.7%	20.3%	3.7%	305.0%	77.8%	36.6%	77.1%
REFUNDS	20,123	118,303	109,296	32,511	280,232	49,952	155,439	58,361	35,167	298,918
%CHYA	-39.4%	563.4%	327.0%	-82.2%	8.0%	148.2%	31.4%	-46.6%	8.2%	6.7%
TOTAL	131,262	87,054	73,323	203,120	494,759	172,111	124,202	105,597	219,860	621,770
%CHYA	15.6%	-23.5%	-20.3%	52.0%	9.2%	31.1%	42.7%	44.0%	8.2%	25.7%

	2015:3	2015:4	2016:1	2016:2	FY 2016	2016:3	2016:4	2017:1	2017:2	FY 2017
ADVANCE PAYMENTS	173,329	220,326	118,673	202,813	715,141	136,698	215,677	102,663	195,412	650,449
%CHYA	-10.3%	6.9%	11.2%	10.5%	3.7%	-21.1%	-2.1%	-13.5%	-3.6%	-9.0%
FINAL PAYMENTS	67,305	59,752	63,509	70,433	260,998	44,746	93,441	52,164	81,824	272,175
%CHYA	133.6%	-18.8%	10.9%	-1.4%	13.0%	-33.5%	56.4%	-17.9%	16.2%	4.3%
REFUNDS	42,388	156,984	85,446	81,453	366,271	39,680	166,537	73,066	57,733	337,016
%CHYA	-15.1%	1.0%	46.4%	131.6%	22.5%	-6.4%	6.1%	-14.5%	-29.1%	-8.0%
TOTAL	198,245	123,094	96,736	191,793	609,868	141,764	142,581	81,761	219,503	585,608
%CHYA	15.2%	-0.9%	-8.4%	-12.8%	-1.9%	-28.5%	15.8%	-15.5%	14.4%	-4.0%

	2017:3	2017:4	2018:1	2018:2	FY 2018	2018:3	2018:4	2019:1	2019:2	FY 2019
ADVANCE PAYMENTS	179,603	185,787	182,395	303,835	851,620	222,891	249,768	158,748	264,445	895,852
%CHYA	31.4%	-13.9%	77.7%	55.5%	30.9%	24.1%	34.4%	-13.0%	-13.0%	5.2%
FINAL PAYMENTS	42,600	66,460	46,270	108,539	263,869	74,735	102,942	68,818	174,861	421,356
%CHYA	-4.8%	-28.9%	-11.3%	32.6%	-3.1%	75.4%	54.9%	48.7%	61.1%	59.7%
REFUNDS	72,225	129,963	122,291	54,224	378,703	43,428	167,871	128,586	50,616	390,501
%CHYA	82.0%	-22.0%	67.4%	-6.1%	12.4%	-39.9%	29.2%	5.1%	-6.7%	3.1%
TOTAL	149,978	122,284	106,374	358,150	736,786	254,198	184,839	98,980	388,690	926,707
%CHYA	5.8%	-14.2%	30.1%	63.2%	25.8%	69.5%	51.2%	-7.0%	8.5%	25.8%

TABLE B.5 **OREGON CORPORATE INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted **September 2021**

	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
ADVANCE PAYMENTS	236,341	346,651	137,782	263,138	983,912	260,668	378,192	249,855	381,413	1,270,128
%CHYA	6.0%	38.8%	-13.2%	-0.5%	9.8%	10.3%	9.1%	81.3%	44.9%	29.1%
FINAL PAYMENTS	67,657	105,446	66,346	111,149	350,598	114,684	98,371	78,356	263,524	554,935
%CHYA	-9.5%	2.4%	-3.6%	-36.4%	-16.8%	69.5%	-6.7%	18.1%	137.1%	58.3%
REFUNDS	73,866	247,403	91,312	86,858	499,439	62,538	254,020	154,026	153,392	623,976
%CHYA	70.1%	47.4%	-29.0%	71.6%	27.9%	-15.3%	2.7%	68.7%	76.6%	24.9%
TOTAL	230,132	204,694	112,816	287,429	835,071	312,814	222,543	174,185	491,545	1,201,087
%CHYA	-9.5%	10.7%	14.0%	-26.1%	-9.9%	35.9%	8.7%	54.4%	71.0%	43.8%

	2021:3	2021:4	2022:1	2022:2	FY 2022	2022:3	2022:4	2023:1	2023:2	FY 2023
ADVANCE PAYMENTS	249,412	290,450	155,288	225,794	920,943	195,338	241,428	137,088	214,732	788,586
%CHYA	-4.3%	-23.2%	-37.8%	-40.8%	-27.5%	-21.7%	-16.9%	-11.7%	-4.9%	-14.4%
FINAL PAYMENTS	108,212	240,963	81,969	125,707	556,851	55,912	206,338	72,464	129,401	464,115
%CHYA	-5.6%	145.0%	4.6%	-52.3%	0.3%	-48.3%	-14.4%	-11.6%	2.9%	-16.7%
REFUNDS	75,957	381,906	149,630	86,720	694,213	75,830	322,136	138,825	89,534	626,325
%CHYA	21.5%	50.3%	-2.9%	-43.5%	11.3%	-0.2%	-15.7%	-7.2%	3.2%	-9.8%
TOTAL	281,667	149,507	87,627	264,781	783,581	175,421	125,630	70,727	254,599	626,377
%CHYA	-10.0%	-32.8%	-49.7%	-46.1%	-34.8%	-37.7%	-16.0%	-19.3%	-3.8%	-20.1%

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
ADVANCE PAYMENTS	187,056	241,126	137,309	215,566	781,057	187,571	244,024	142,088	223,114	796,797
%CHYA	-4.2%	-0.1%	0.2%	0.4%	-1.0%	0.3%	1.2%	3.5%	3.5%	2.0%
FINAL PAYMENTS	113,154	273,032	149,721	212,512	748,419	137,041	331,089	176,438	246,800	891,367
%CHYA	102.4%	32.3%	106.6%	64.2%	61.3%	21.1%	21.3%	17.8%	16.1%	19.1%
REFUNDS	95,041	348,406	180,089	124,034	747,571	108,486	399,382	201,089	138,673	847,630
%CHYA	25.3%	8.2%	29.7%	38.5%	19.4%	14.1%	14.6%	11.7%	11.8%	13.4%
TOTAL	205,169	165,753	106,940	304,043	781,904	216,126	175,731	117,437	331,241	840,535
%CHYA	17.0%	31.9%	51.2%	19.4%	24.8%	5.3%	6.0%	9.8%	8.9%	7.5%

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
ADVANCE PAYMENTS	196,216	260,177	149,660	235,330	841,383	205,919	270,012	154,815	243,569	874,314
%CHYA	4.6%	6.6%	5.3%	5.5%	5.6%	4.9%	3.8%	3.4%	3.5%	3.9%
FINAL PAYMENTS	164,545	391,738	188,524	281,453	1,026,259	187,303	409,956	198,402	312,156	1,107,817
%CHYA	20.1%	18.3%	6.9%	14.0%	15.1%	13.8%	4.7%	5.2%	10.9%	7.9%
REFUNDS	120,721	448,385	204,468	141,084	914,657	123,600	455,725	207,884	143,469	930,678
%CHYA	11.3%	12.3%	1.7%	1.7%	7.9%	2.4%	1.6%	1.7%	1.7%	1.8%
TOTAL	240,040	203,530	133,716	375,699	952,985	269,622	224,243	145,334	412,256	1,051,454
%CHYA	11.1%	15.8%	13.9%	13.4%	13.4%	12.3%	10.2%	8.7%	9.7%	10.3%

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
ADVANCE PAYMENTS	210,385	274,911	155,874	245,289	886,460	215,167	281,203	159,077	250,361	905,808
%CHYA	2.2%	1.8%	0.7%	0.7%	1.4%	2.3%	2.3%	2.1%	2.1%	2.2%
FINAL PAYMENTS	205,586	418,360	202,277	328,520	1,154,744	220,154	430,296	208,121	346,024	1,204,595
%CHYA	9.8%	2.1%	2.0%	5.2%	4.2%	7.1%	2.9%	2.9%	5.3%	4.3%
REFUNDS	127,409	469,753	213,073	147,065	957,300	128,586	474,147	215,092	148,469	966,295
%CHYA	3.1%	3.1%	2.5%	2.5%	2.9%	0.9%	0.9%	0.9%	1.0%	0.9%
TOTAL	288,561	223,519	145,078	426,745	1,083,903	306,735	237,352	152,106	447,915	1,144,108
%CHYA	7.0%	-0.3%	-0.2%	3.5%	3.1%	6.3%	6.2%	4.8%	5.0%	5.6%

Table B.6 Cigarette and Tobacco Tax Distribution

TABLE B.6 September 2021
Cigarette & Tobacco Tax Distribution (Millions of $)

	Cigarette Tax Distribution*					Tobacco Use Reduction[2]			Other Tobacco Tax Distribution				Inhalent Delivery Distribution		
	Total	General Fund	Health Plan	Mental Health	Health Authority[1]	Old	New	Cities, Counties & Public Transit	Total	General Fund	Health Plan	Tobacco Use Reduction	Total	Health Authority	Tobacco Use Reduction
Distribution Forecast															
2019-20	187.2	30.5	121.0	21.2	0.0	4.8	0.0	9.7	57.7	30.9	24.1	2.7	0.0	0.0	0.0
2020-21	292.3	24.6	107.1	18.7	118.9	4.3	10.1	8.5	56.6	30.4	23.6	2.6	10.5	9.5	1.1
2019-21 Biennium	479.5	55.1	228.1	39.9	118.9	9.1	10.1	18.2	114.3	61.3	47.7	5.3	10.5	9.5	1.1
2021-22	342.2	22.5	87.7	15.3	185.7	3.5	20.5	7.0	60.3	32.5	25.0	2.8	9.8	8.8	1.0
2022-23	336.1	22.2	86.5	15.1	181.7	3.5	20.2	6.9	60.7	32.7	25.2	2.8	9.9	8.9	1.0
2021-23 Biennium	678.3	44.7	174.2	30.5	367.4	6.9	40.6	13.9	121.0	65.1	50.2	5.6	19.7	17.7	2.0
2023-24	333.1	22.0	85.8	15.0	180.1	3.4	20.0	6.8	60.8	32.7	25.2	2.8	10.2	9.1	1.0
2024-25	325.3	21.5	83.8	14.7	175.8	3.3	19.5	6.7	61.2	32.9	25.4	2.8	10.3	9.2	1.0
2023-25 Biennium	658.4	43.5	169.5	29.7	355.9	6.8	39.5	13.5	121.9	65.6	50.6	5.6	20.4	18.4	2.0
2025-26	315.9	20.9	81.3	14.2	170.7	3.2	19.0	6.5	61.2	32.9	25.4	2.8	10.3	9.3	1.0
2026-27	309.8	20.5	79.8	14.0	167.5	3.2	18.6	6.4	61.5	33.1	25.5	2.8	10.4	9.4	1.0
2025-27 Biennium	625.7	41.3	161.1	28.2	338.2	6.4	37.6	12.9	122.7	66.0	51.0	5.7	20.8	18.7	2.1
2027-28	304.5	20.1	78.4	13.7	164.6	3.1	18.3	6.3	61.4	33.1	25.5	2.8	10.5	9.5	1.1
2028-29	299.8	19.8	77.2	13.5	162.1	3.1	18.0	6.2	61.3	33.0	25.5	2.8	10.6	9.5	1.1
2027-29 Biennium	604.3	39.9	155.6	27.2	326.7	6.2	36.3	12.4	122.7	66.1	51.0	5.7	21.1	19.0	2.1
2029-30	295.2	19.5	76.0	13.3	159.6	3.0	17.7	6.1	61.2	32.9	25.4	2.8	10.7	9.6	1.1
2030-31	290.6	19.2	74.8	13.1	157.1	3.0	17.5	6.0	61.0	32.9	25.4	2.8	10.8	9.7	1.1
2029-31 Biennium	585.8	38.7	150.8	26.4	316.7	6.0	35.2	12.0	122.2	65.8	50.8	5.6	21.4	19.3	2.1

[1] Includes the cigarette floor tax in FY21 of $27.7 million and FY22 of $1.6 million

[2] Old and New refere to pre- and post-Measure 108 (2020) taxes and programs

Table B.7 Revenue Distribution to Local Governments

TABLE B.7 **September 2021**

Liquor Apportionment and Revenue Distribution to Local Governments (Millions of $)

	Liquor Apportionment Distribution								
					City Revenue				
	Total Liquor Revenue Available	General Fund (56%)	Mental Health[1]	Oregon Wine Board	Revenue Sharing	Regular	Total	Counties	Cigarette Tax Distribution[2]
2019-20	290.649	165.629	9.534	0.338	52.340	36.638	88.979	26.170	9.653
2020-21	314.814	179.338	10.123	0.359	56.815	39.771	96.586	28.408	8.546
2019-21 Biennium	605.463	344.967	19.657	0.697	109.155	76.409	185.564	54.578	18.199
2021-22	295.864	168.764	9.887	0.363	53.114	37.180	90.294	26.557	6.996
2022-23	311.535	177.703	10.410	0.382	55.927	39.149	95.076	27.964	6.903
2021-23 Biennium	607.399	346.467	20.297	0.745	109.041	76.329	185.370	54.521	13.899
2023-24	309.147	168.162	10.633	0.384	59.078	41.353	100.431	29.537	6.843
2024-25	323.442	176.334	10.856	0.395	61.754	43.227	104.981	30.875	6.681
2023-25 Biennium	632.589	344.497	21.489	0.779	120.832	84.580	205.412	60.412	13.524
2025-26	338.695	185.051	11.100	0.407	45.225	64.610	109.835	32.303	6.488
2026-27	354.720	194.204	11.363	0.420	47.324	67.608	114.932	33.801	6.364
2025-27 Biennium	693.414	379.254	22.462	0.828	92.549	132.217	224.766	66.104	12.852
2027-28	371.349	203.701	11.636	0.434	49.502	70.719	120.220	35.357	6.255
2028-29	388.504	213.502	11.914	0.448	51.749	73.929	125.677	36.962	6.158
2027-29 Biennium	759.853	417.203	23.550	0.883	101.250	144.647	245.898	72.319	12.413
2029-30	406.459	223.774	12.200	0.463	54.098	77.285	131.382	38.640	6.063
2030-31	425.250	234.540	12.492	0.478	56.553	80.793	137.346	40.394	5.970
2029-31 Biennium	831.708	458.314	24.692	0.941	110.651	158.078	268.729	79.033	12.033

[1] Mental Health Alcoholism and Drug Services Account, per ORS 471.810

[2] For details on cigarette revenues see TABLE B.6 on previous page

Table B.8 Track Record for the May 2021 Forecast

Table B.8 Track Record for the May 2021 Forecast

(Quarter ending June 30, 2021)

Personal Income Tax	Forecast Comparison			Year/Year Change	
(Millions of dollars)	Actual Revenues	Latest Forecast	Percent Difference	Prior Year	Percent Change
Withholding	$2,266.8	$2,116.8	7.1%	$1,997.7	13.5%
Dollar difference		$150.0		$131.0	
Estimated Payments*	$701.9	$540.7	29.8%	$428.8	63.7%
Dollar difference		$161.2		$131.8	
Final Payments*	$1,500.2	$1,329.2	12.9%	$330.3	354.2%
Dollar difference		$171.0		$25.5	
Refunds	-$672.4	-$736.7	-8.7%	-$735.9	-8.6%
Dollar difference		$64.3		$63.5	
Total Personal Income Tax	**$3,796.5**	**$3,250.0**	**16.8%**	**$2,020.8**	**87.9%**
Dollar difference		$546.5		$1,775.6	

Corporate Income Tax	Forecast Comparison			Year/Year Change	
(Millions of dollars)	Actual Revenues	Latest Forecast	Percent Difference	Prior Year	Percent Change
Advanced Payments	$381.4	$315.2	21.0%	$263.1	44.9%
Dollar difference		$66.2		$118.3	
Final Payments	$263.5	$136.3	93.3%	$111.1	137.1%
Dollar difference		$127.2		$152.4	
Refunds	-$153.4	-$141.1	8.7%	-$86.9	76.6%
Dollar difference		-$12.3		-$66.5	
Total Corporate Income Tax	**$491.5**	**$310.4**	**58.3%**	**$287.4**	**71.0%**
Dollar difference		$181.1		$204.1	

Total Income Tax	Forecast Comparison			Year/Year Change	
(Millions of dollars)	Actual Revenues	Latest Forecast	Percent Difference	Prior Year	Percent Change
Corporate and Personal Tax	**$4,288.0**	**$3,560.4**	**20.4%**	**$2,308.3**	**85.8%**
Dollar difference		$727.6		$1,979.7	

* Data separating estimated and other personal income tax payments is no longer available. Tracking represents estimates based on banking data.

Table B.9 Summary of Lottery Resources

TABLE B.9
Summary of Lottery Resources

Sep 2021 Forecast

(in millions of dollars)	2021-23 Current Forecast	2021-23 *Change from May-21*	2021-23 *Change from COS 2021*	2023-25 Current Forecast	2023-25 *Change from May-21*	2025-2027 Current Forecast	2025-2027 *Change from May-21*	2027-29 Current Forecast	2027-29 *Change from May-21*	2029-31 Current Forecast	2029-31 *Change from May-21*
LOTTERY EARNINGS											
Traditional Lottery	158.003	*(0.832)*	*(0.832)*	157.181	*(0.056)*	156.454	(0.053)	156.863	(0.050)	156.957	*NA*
Video Lottery	1,519.423	*46.135*	*46.135*	1,578.125	*12.632*	1,712.340	15.244	1,856.637	12.906	1,988.089	*NA*
Scoreboard (Sports Betting)[1]	22.538	*3.201*	*3.201*	35.952	*0.000*	41.763	0.000	44.911	0.000	48.296	*NA*
Administrative Actions	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	*NA*
Total Available to Transfer	1,699.965	*48.504*	*48.504*	1,771.258	*12.576*	1,910.557	15.191	2,058.411	12.856	2,193.342	*NA*
ECONOMIC DEVELOPMENT FUND											
Beginning Balance	72.370	*0.000*	*0.000*	61.770	*61.770*	0.000	0.000	0.000	0.000	0.000	*NA*
Transfers from Lottery	1,699.965	*48.504*	*48.504*	1,771.258	*12.576*	1,910.557	15.191	2,058.411	12.856	2,193.342	*NA*
Other Resources[2]	2.000	*0.000*	*0.000*	2.000	*0.000*	2.000	0.000	2.000	0.000	2.000	*NA*
Total Available Resources	1,774.335	*48.504*	*48.504*	1,835.028	*74.346*	1,912.557	15.191	2,060.411	12.856	2,195.342	*NA*
ALLOCATION OF RESOURCES											
Constitutional Distributions											
Education Stability Fund[3]	305.994	*8.731*	*8.731*	318.566	2.003	254.625	2.681	136.219	2.200	145.052	*NA*
Oregon Capital Matching Fund[3]	0.000	*0.000*	*0.000*	0.000	0.000	74.316	(0.035)	195.178	0.010	207.810	*NA*
Parks and Natural Resources Fund[4]	254.995	*7.276*	*7.276*	265.689	1.886	286.584	2.279	308.762	1.928	329.001	*NA*
Veterans' Services Fund[5]	25.499	*0.728*	*0.728*	26.569	0.189	28.658	0.228	30.876	0.193	32.900	*NA*
Other Distributions											
Outdoor School Education Fund[6]	49.419	*0.000*	*0.000*	51.222	0.000	53.394	0.000	55.658	0.000	58.019	*NA*
County Economic Development	54.210	*(2.276)*	*0.000*	60.505	0.484	65.651	0.584	71.183	0.495	76.223	*NA*
HECC Collegiate Athletic & Scholarships[7]	16.515	*(0.000)*	*0.000*	17.713	0.126	19.106	0.152	20.584	0.129	21.933	*NA*
Gambling Addiction [7]	16.515	*(0.000)*	*0.000*	17.713	0.126	19.106	0.152	20.584	0.129	21.933	*NA*
County Fairs	3.828	*0.000*	*0.000*	3.828	0.000	3.828	0.000	3.828	0.000	3.828	*NA*
Other Legislatively Adopted Allocations[8]	972.925	*734.025*	*0.000*	234.300	0.000	234.300	0.000	234.300	0.000	234.300	*NA*
Employer Incentive Fund (PERS)[1]	12.666	*0.000*	*0.000*	23.554	0.005	27.682	(0.001)	30.270	(0.003)	32.557	*NA*
Total Distributions	1,712.564	*748.483*	*16.734*	1,019.657	4.819	1,067.250	6.040	1,107.443	5.080	1,163.557	*NA*
Ending Balance/Discretionary Resources	61.770	*(699.978)*	*31.770*	815.371	69.527	845.307	9.151	952.968	7.776	1,031.785	*NA*

Note: Some totals may not foot due to rounding.
1. Sports Betting revenues are transferred to Economic Development Fund making them subject to the constitutional distributions, after which the remainder is transferred to the Employer Incentive Fund
2. Includes reversions (unspent allocations from previous biennium) and interest earnings on Economic Development Fund.
3. Eighteen percent of proceeds accrue to the Ed. Stability Fund, until the balance equals 5% of GF Revenues. Thereafter, 15% of proceeds accrue to the School Capital Matching Fund.
4. The Parks and Natural Resources Fund Constitutional amendment requires 15% of net proceeds be transferred to this fund.
5. Per Ballot Measure 96 (2016), 1.5% of net lottery proceeds are dedicated to the Veterans' Services Fund
6. Per Ballot Measure 99 (2016), the lesser of 4% of Lottery transfers or $22 million per year is transferred to the Outdoor Education Account. Adjusted annually for inflation.
7. Approximately one percent of net lottery proceeds are dedicated to each program. Certain limits are imposed by the Legislature.
8. Includes Debt Service Allocations, Allocations to State School Fund and Other Agency Allocations

Table B.10 Budgetary Reserve Summary and Outlook

Table B.10: Budgetary Reserve Summary and Outlook **Sep 2021**

Rainy Day Fund

(Millions)	2019-21	2021-23	2023-25	2025-27	2027-29
Beginning Balance	$666.6	$962.2	$1,256.4	$1,605.0	$2,026.0
Interest Earnings	$22.8	$11.4	$26.6	$64.5	$117.3
Deposits[1]	$272.8	$282.9	$322.0	$356.6	$389.9
Triggered Withdrawals	$0.0	$0.0	$0.0	$0.0	$0.0
Ending Balance[2]	**$962.2**	**$1,256.4**	**$1,605.0**	**$2,026.0**	**$2,533.1**

Education Stability Fund[3]

(Millions)	2019-21	2021-23	2023-25	2025-27	2027-29
Beginning Balance	$621.1	$414.6	$689.7	$976.5	$1,205.6
Interest Earnings[4]	$20.1	$5.9	$16.0	$41.1	$69.6
Deposits[5]	$194.7	$275.4	$286.7	$229.2	$122.6
Distributions	$419.9	$6.1	$16.0	$41.1	$69.6
Oregon Education Fund	$0.0	$0.0	$0.0	$0.0	$0.0
Oregon Opportunity Grant	$19.9	$6.1	$16.0	$41.1	$69.6
Withdrawals	$400.0	$0.0	$0.0	$0.0	$0.0
Ending Balance	**$414.6**	**$689.7**	**$976.5**	**$1,205.6**	**$1,328.2**

Total Reserves

(Millions)	2019-21	2021-23	2023-25	2025-27	2027-29
Ending Balances	**$1,376.8**	**$1,946.2**	**$2,581.4**	**$3,231.6**	**$3,861.4**
Percent of General Fund Revenues	5.8%	8.3%	9.4%	10.8%	11.6%

Footnotes:

1. Includes transfer of ending General Fund balances up to 1% of budgeted appropriations as well as private donations. Assumes future appropriations equal to 98.75 percent of available resources. Includes forecast for corporate income taxes above rate of 6.6% for the biennium are deposited on or before Jun 30 of each odd-numbered year.
2. Available funds in a given biennium equal 2/3rds of the beginning balance under current law.
3. Excludes funds in the Oregon Growth and the Oregon Resource and Technology Development subaccounts.
4. Interest earnings are distributed to the Oregon Education Funds (75%) and the State Scholarship Fund (25%), provided there remains debt outstanding. In the event that debt is paid off, all interest earnings distributed to the State Scholarship Fund.
5. Contributions to the ESF are capped at 5% of the prior biennium's General Fund revenue total. Quarterly contributions are made until the balance exceeds the cap.

Table B.11 Recreational Marijuana Resources and Distributions

TABLE B.11
Summary of Marijuana Resources

Sep 2021

(in millions of dollars)	2021-23 Current Forecast	2021-23 Change from May-21	2021-23 Change from COS 2021	2023-25 Current Forecast	2023-25 Change from May-21	2025-27 Current Forecast	2025-27 Change from May-21	2027-29 Current Forecast	2027-29 Change from May-21	2029-31 Current Forecast	2029-31 Change from May-21
MARIJUANA EARNINGS											
+ Tax Revenue [1]	352.403	(1.983)	(1.983)	377.204	0.000	417.310	0.000	462.371	0.000	512.390	NA
+ Medical Marijuana Tax Revenue [2]	0.000	0.000	0.000	0.000	0.000	0.000	0.000	31.896	31.896	44.041	NA
- Administrative Costs [3]	15.026	0.000	0.000	15.374	0.000	15.746	0.000	16.144	0.000	16.571	NA
Net Available to Transfer	337.377	(1.983)	(1.983)	361.830	0.000	401.564	0.000	446.227	0.000	495.819	NA
OREGON MARIJUANA ACCOUNT											
Beginning Balance	0.000	0.000	(0.000)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	NA
Revenue Transfers	337.377	(1.983)	(1.983)	361.830	0.000	401.564	0.000	478.123	31.896	539.860	NA
Other Resources	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	NA
Total Available Resources	337.377	(1.983)	(1.983)	361.830	0.000	401.564	0.000	478.123	31.896	539.860	NA
ALLOCATION OF RESOURCES [4]											
Drug Treatment & Recovery	247.377	(1.983)	(1.983)	271.830	0.000	311.564	0.000	388.123	31.896	449.860	NA
State School Fund	36.000	0.000	0.000	36.000	0.000	36.000	0.000	36.000	0.000	36.000	NA
Mental Health, Alcoholism, & Drug Services	18.000	0.000	0.000	18.000	0.000	18.000	0.000	18.000	0.000	18.000	NA
State Police	13.500	0.000	0.000	13.500	0.000	13.500	0.000	13.500	0.000	13.500	NA
Cities	9.000	0.000	0.000	9.000	0.000	9.000	0.000	9.000	0.000	9.000	NA
Counties	9.000	0.000	0.000	9.000	0.000	9.000	0.000	9.000	0.000	9.000	NA
Alcohol & Drug Abuse Prevention, Intervention & Treatment	4.500	0.000	0.000	4.500	0.000	4.500	0.000	4.500	0.000	4.500	NA
Total Distributions	337.377	(1.983)	(1.983)	361.830	0.000	401.564	0.000	478.123	31.896	539.860	NA
Ending Balance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	NA

Note: Some totals may not foot due to rounding.

1. Retailers pay taxes monthly, however taxes are not available for distribution to recepient programs until the Department of Revenue receives and processes retailers' quarterly tax returns. As such, there is a one to two quarter lag between when the initial monthly payments are made and when monies be come available to distribute.

2. Medical marijuana being exempt from tax is an explicit tax expenditure per HB 2433 (2021). Tax expenditures sunset after 6 years, although they may be renewed at that time. Current law is that medical marijuana sales will be taxed beginning January 1, 2028.

3. Administrative Costs reflect monthly collection costs for the Department of Revenue in addition to distributions to the Criminal Justice Commission and OLCC per SB 1544 (2018)

4. Per Measure 110 (2020), the first $11.25 million per quarter ($45m per year) is distributed via forumula to the initial recipient programs. All revenues above $11.25 million go to the Drug Treatment & Recovery Fund.

Table B.12 Fund for Student Success (Corporate Activity Tax)

TABLE B.12 | Sep 2021
Summary of Corporate Activity Tax Resources

(in millions of dollars)	2019-21 Current Forecast	2019-21 Change from May-21	2021-23 Current Forecast	2021-23 Change from May-21	2021-23 Change from COS 2021	2023-25 Current Forecast	2023-25 Change from May-21	2025-27 Current Forecast	2025-27 Change from May-21	2027-29 Current Forecast	2027-29 Change from May-21
Corporate Activity Tax											
+ Tax Revenue	1,374.904	36.935	2,376.769	8.472	*8.472*	2,597.307	*9.249*	2,878.741	*6.024*	3,204.419	*8.972*
- Administrative Costs	14.002	0.000	19.200	0.000	*0.000*	21.312	*0.000*	23.656	*0.000*	26.259	*0.000*
Net Available to Transfer	1,360.902	36.935	2,357.569	8.472	8.472	2,575.995	9.249	2,855.084	6.024	3,178.161	8.972
Fund for Student Success											
Beginning Balance	0.000	0.000	168.800	30.388	*30.388*	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*
Revenue Transfers	1,360.902	36.935	2,357.569	8.472	*8.472*	2,575.995	*9.249*	2,855.084	*6.024*	3,178.161	*8.972*
Other Resources	0.000	0.000	0.000	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*
Total Available Resources	1,360.902	36.935	2,526.369	38.860	38.860	2,575.995	9.249	2,855.084	6.024	3,178.161	8.972
ALLOCATION OF RESOURCES											
State School Fund	624.961	6.547	693.125	7.447	*7.447*	764.379	*6.117*	833.183	*5.946*	909.194	*7.352*
Student Investment Account	150.000	0.000	916.622	84.913	*24.345*	905.808	*1.566*	1,010.951	*0.039*	1,134.483	*0.810*
Statewide Education Initiative Account	246.622	0.000	549.973	50.948	*177.072*	543.485	*0.940*	606.571	*0.023*	680.690	*0.486*
Early Learning Account	170.518	0.000	366.649	33.965	*(69.458)*	362.323	*0.626*	404.380	*0.016*	453.793	*0.324*
Total Distributions	1,192.102	6.547	2,526.369	177.272	139.406	2,575.995	9.249	2,855.084	6.024	3,178.161	8.972
Ending Balance	168.800	30.388	0.000	0.000	(100.546)	0.000	0.000	0.000	0.000	0.000	0.000

Note: Some totals may not foot due to rounding.

Table B.13 Fund for Student Success Quarterly Revenues (Corporate Activity Tax)

Table B.13 **Corporate Activity Tax Collections By Quarter** **Sep-21**

(thousands)	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
Estimated Payments	$0	$0	$4,022.75	$222,495	$226,518	$224,973	$254,387	$223,550	$270,784	$973,693
Final Payments	$0	$0	$0	$0	$0	$0	$0	$26,911	$163,436	$190,348
Refunds (-)	$0	$0	$0	$0	$0	$0	$0	$997.05	$14,657	$15,654
Total	$0	$0	$4,023	$222,495	$226,518	$224,973	$254,387	$249,464	$419,563	$1,148,387

	2021:3	2021:4	2022:1	2022:2	FY 2022	2022:3	2022:4	2023:1	2023:2	FY 2023
Estimated Payments	$259,031	$248,000	$268,068	$231,378	$1,006,477	$257,356	$246,397	$266,335	$243,478	$1,013,566
Final Payments	$1,833	$7,333	$18,039	$153,334	$180,540	$1,804	$7,216	$20,602	$175,113	$204,735
Refunds (-)	$0	$9,082	$1,336	$4,009	$14,427	$0	$8,017	$1,526	$4,578	$14,122
Total	$260,864	$246,251	$284,771	$380,704	$1,172,590	$259,160	$245,595	$285,411	$414,013	$1,204,179

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Estimated Payments	$270,814	$259,282	$280,263	$255,670	$1,066,029	$284,376	$272,266	$294,297	$268,946	$1,119,884
Final Payments	$2,060	$8,241	$21,679	$184,271	$216,251	$2,168	$8,672	$22,765	$193,498	$227,102
Refunds (-)	$0	$9,156	$1,606	$4,818	$15,580	$0	$9,635	$1,686	$5,059	$16,380
Total	$272,875	$258,366	$300,336	$435,124	$1,266,700	$286,544	$271,302	$315,375	$457,385	$1,330,607

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Estimated Payments	$299,142	$286,403	$309,578	$283,858	$1,178,981	$315,728	$302,283	$326,743	$299,397	$1,244,151
Final Payments	$2,276	$9,106	$23,947	$203,546	$238,874	$2,395	$9,579	$25,274	$214,832	$252,079
Refunds (-)	$0	$10,118	$1,774	$5,321	$17,213	$0	$10,643	$1,872	$5,617	$18,132
Total	$301,418	$285,391	$331,751	$482,082	$1,400,642	$318,123	$301,219	$350,146	$508,612	$1,478,098

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Estimated Payments	$333,011	$318,830	$344,630	$315,916	$1,312,387	$351,385	$336,422	$363,645	$333,456	$1,384,908
Final Payments	$2,527	$10,110	$26,658	$226,592	$265,887	$2,666	$10,663	$28,129	$239,094	$280,552
Refunds (-)	$0	$11,233	$1,975	$5,924	$19,132	$0	$11,848	$2,084	$6,251	$20,182
Total	$335,539	$317,707	$369,313	$536,584	$1,559,142	$354,051	$335,237	$389,690	$566,299	$1,645,277

APPENDIX C: POPULATION FORECASTS BY AGE AND SEX

Table C.1 Oregon's Population Forecasts and Component of Change 1990-2029

STATE OF OREGON
POPULATION FORECASTS
COMPONENTS OF CHANGE 1990 -2029

Year		Population Change		Births		Deaths		Natural	Net Migration	
(July 1)	Population	Number	Percent	Number	Rate/1000	Number	Rate/1000	Increase	Number	Rate/1000
1990	2,860,400	69,800	2.50	42,008	14.87	24,763	8.76	17,245	52,555	18.60
1991	2,928,500	68,100	2.38	42,682	14.75	24,944	8.62	17,738	50,362	17.40
1992	2,991,800	63,300	2.16	42,427	14.33	25,166	8.50	17,261	46,039	15.55
1993	3,060,400	68,600	2.29	41,442	13.69	26,543	8.77	14,899	53,701	17.75
1994	3,121,300	60,900	1.99	41,487	13.42	27,564	8.92	13,923	46,977	15.20
1995	3,184,400	63,100	2.02	42,426	13.46	27,552	8.74	14,874	48,226	15.30
1990-1995		**324,000**		**210,464**		**131,769**		**78,695**	**245,305**	
1996	3,247,100	62,700	1.97	43,196	13.43	28,768	8.95	14,428	48,272	15.01
1997	3,304,300	57,200	1.76	43,625	13.32	29,201	8.91	14,424	42,776	13.06
1998	3,352,400	48,100	1.46	44,696	13.43	28,705	8.62	15,991	32,109	9.65
1999	3,393,900	41,500	1.24	45,188	13.40	29,848	8.85	15,340	26,160	7.76
2000	3,431,100	37,200	1.10	45,534	13.34	28,909	8.47	16,625	20,575	6.03
1995-2000		**246,700**		**222,239**		**145,431**		**76,808**	**169,892**	
2001	3,470,400	39,300	1.15	45,536	13.20	29,934	8.67	15,602	23,698	6.87
2002	3,502,600	32,200	0.93	44,995	12.91	30,828	8.84	14,167	18,033	5.17
2003	3,538,600	36,000	1.03	45,686	12.98	30,604	8.69	15,082	20,918	5.94
2004	3,578,900	40,300	1.14	45,599	12.81	30,721	8.63	14,878	25,422	7.14
2005	3,626,900	48,000	1.34	45,892	12.74	30,717	8.53	15,175	32,825	9.11
2000-2005		**195,800**		**227,708**		**152,804**		**74,904**	**120,896**	
2006	3,685,200	58,300	1.61	46,946	12.84	30,771	8.42	16,175	42,125	11.52
2007	3,739,400	54,200	1.47	49,404	13.31	31,396	8.46	18,008	36,192	9.75
2008	3,784,200	44,800	1.20	49,659	13.20	32,008	8.51	17,651	27,149	7.22
2009	3,815,800	31,600	0.84	47,960	12.62	31,382	8.26	16,578	15,022	3.95
2010	3,837,300	21,500	0.56	46,256	12.09	31,689	8.28	14,567	6,933	1.81
2005-2010		**210,400**		**240,225**		**157,246**		**82,979**	**127,421**	
2011	3,857,625	20,325	0.53	45,381	11.80	32,437	8.43	12,944	7,381	1.92
2012	3,878,223	20,598	0.53	44,897	11.61	32,804	8.48	12,093	8,505	2.20
2013	3,910,991	32,768	0.84	44,969	11.55	33,168	8.52	11,801	20,967	5.38
2014	3,952,098	41,107	1.05	45,447	11.56	33,731	8.58	11,716	29,391	7.48
2015	4,000,572	48,474	1.23	45,660	11.48	35,318	8.88	10,342	38,132	9.59
2010-2015		**163,272**		**226,354**		**167,458**		**58,896**	**104,376**	
2016	4,060,302	59,730	1.49	45,647	11.33	35,339	8.77	10,308	49,422	12.26
2017	4,122,197	61,895	1.52	44,602	10.90	36,773	8.99	7,829	54,066	13.22
2018	4,173,516	51,319	1.24	42,906	10.34	36,268	8.74	6,638	44,681	10.77
2019	4,211,746	38,230	0.92	42,220	10.07	36,622	8.73	5,598	32,632	7.78
2020	4,240,535	28,788	0.68	40,920	9.68	37,916	8.97	3,004	25,784	6.10
2015-2020		**239,962**		**216,295**		**182,918**		**33,377**	**206,585**	
2021	4,256,700	16,165	0.38	39,553	9.31	40,254	9.47	-701	16,866	3.97
2022	4,285,500	28,800	0.68	39,604	9.27	40,600	9.51	-996	29,796	6.98
2023	4,319,100	33,600	0.78	40,125	9.33	40,217	9.35	-92	33,692	7.83
2024	4,354,300	35,200	0.81	40,754	9.40	40,917	9.44	-163	35,363	8.15
2025	4,390,200	35,900	0.82	41,361	9.46	41,729	9.54	-369	36,269	8.30
2020-2025		**149,665**		**201,396**		**203,717**		**-2,321**	**151,986**	
2026	4,426,000	35,800	0.82	41,512	9.42	42,770	9.70	-1,258	37,058	8.41
2027	4,461,600	35,600	0.80	41,665	9.38	43,781	9.85	-2,117	37,717	8.49
2028	4,496,700	35,100	0.79	41,837	9.34	44,999	10.05	-3,162	38,262	8.54
2029	4,531,300	34,600	0.77	42,004	9.31	46,128	10.22	-4,123	38,723	8.58
1990-2000		**570,700**		**432,703**		**277,200**		**155,503**	**415,197**	13.10
2000-2010		**406,200**		**467,933**		**310,050**		**157,883**	**248,317**	6.83
2010-2020		**403,235**		**442,649**		**350,376**		**92,273**	**310,961**	7.73
2020-2029		**290,765**		**368,415**		**381,395**		**-12,981**	**303,746**	6.96

Sources: 1990-1999 population - U.S. Census Bureau; 2000-2020 intercensal population estimates by Office of Economic Analysis based on postcensal estimates by Population Research Center, PSU; births and deaths 1990-2020: Oregon Center for Health Statistics.

Table C.2 Population Forecasts by Age and Sex: 2010-2029

		2010			2011			2012			2013			2014	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	122,327	116,130	238,457	120,987	115,026	236,013	119,348	113,261	232,609	118,084	111,726	229,809	117,641	111,355	228,996
5- 9	121,539	116,369	237,908	121,698	115,834	237,532	122,594	116,794	239,388	123,803	117,798	241,601	124,423	117,832	242,255
10-14	124,508	118,732	243,241	124,036	118,998	243,034	123,537	118,197	241,733	123,288	118,067	241,355	123,265	118,273	241,538
15-19	131,126	124,540	255,667	128,956	121,854	250,810	127,331	120,478	247,809	126,398	119,738	246,136	126,554	119,807	246,361
20-24	128,787	124,903	253,689	130,378	126,428	256,806	132,513	128,343	260,856	134,820	130,109	264,928	136,146	131,362	267,509
25-29	134,019	131,816	265,835	133,036	130,512	263,548	131,984	129,342	261,326	131,823	129,545	261,369	133,688	131,739	265,427
30-34	131,489	128,325	259,814	133,326	130,609	263,935	135,325	133,042	268,367	136,761	134,599	271,360	139,155	136,712	275,867
35-39	128,070	123,596	251,665	125,846	121,747	247,592	125,867	122,203	248,070	128,441	124,222	252,663	130,502	126,384	256,886
40-44	125,969	122,843	248,811	128,886	125,293	254,179	130,633	126,499	257,131	131,250	127,292	258,542	130,749	126,479	257,228
45-49	130,825	132,538	263,363	127,717	128,485	256,203	125,296	124,883	250,179	123,666	122,052	245,718	124,046	121,306	245,352
50-54	135,129	141,565	276,693	134,628	140,565	275,193	133,344	139,039	272,383	131,925	137,323	269,248	131,353	135,859	267,212
55-59	133,011	140,802	273,812	133,918	142,248	276,166	134,251	142,875	277,126	134,172	142,486	276,658	133,095	141,707	274,803
60-64	115,236	121,045	236,281	121,345	127,751	249,095	122,743	129,419	252,162	124,658	132,621	257,280	127,398	136,557	263,954
65-69	81,854	87,917	169,771	84,373	90,809	175,182	91,992	98,696	190,689	97,819	104,919	202,738	103,311	110,291	213,602
70-74	56,925	62,949	119,874	59,466	65,624	125,090	62,453	69,080	131,533	67,108	73,844	140,952	71,187	78,389	149,576
75-79	40,932	50,101	91,034	41,535	50,063	91,598	42,631	50,669	93,301	44,193	52,029	96,222	46,402	54,096	100,498
80-84	30,391	42,734	73,126	30,481	42,279	72,760	30,523	41,807	72,330	30,720	41,235	71,955	30,976	40,757	71,733
85+	26,800	51,458	78,258	27,586	52,265	79,852	28,336	52,894	81,230	28,956	53,502	82,458	29,464	53,838	83,302
Total	1,898,938	1,938,362	3,837,300	1,908,198	1,946,389	3,854,587	1,920,702	1,957,521	3,878,223	1,937,884	1,973,107	3,910,991	1,959,355	1,992,743	3,952,098
Mdn. Age	37.2	39.4	38.3	37.4	39.7	38.6	37.6	39.9	38.7	37.8	40.0	38.9	38.0	40.1	39.0

		2015			2016			2017			2018			2019	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	117,832	111,402	229,234	118,824	112,042	230,866	119,324	112,522	231,847	118,391	111,540	229,931	116,313	109,664	225,977
5- 9	125,093	118,059	243,153	125,047	117,809	242,856	124,692	116,926	241,618	124,139	115,817	239,956	123,915	115,526	239,441
10-14	122,790	118,088	240,878	123,562	118,345	241,907	125,238	120,218	245,456	126,834	121,672	248,507	127,566	121,795	249,360
15-19	127,405	120,435	247,840	128,086	121,399	249,485	128,746	121,584	250,330	128,802	121,621	250,423	128,481	121,629	250,110
20-24	136,603	131,868	268,471	136,733	131,795	268,528	137,266	132,434	269,700	137,258	132,592	269,851	137,177	132,118	269,295
25-29	136,868	135,641	272,509	142,348	142,206	284,554	147,878	148,337	296,215	152,390	152,970	305,359	153,927	154,621	308,548
30-34	140,518	137,748	278,266	142,817	139,473	282,290	144,710	141,317	286,027	146,397	143,507	289,903	148,917	146,719	295,636
35-39	133,981	129,538	263,520	137,506	132,717	270,223	141,431	136,408	277,839	144,005	138,623	282,628	146,882	141,059	287,942
40-44	129,681	125,051	254,732	128,631	124,035	252,666	129,719	125,351	255,070	132,977	127,802	260,780	135,162	130,004	265,166
45-49	126,722	123,327	250,050	130,824	126,526	257,350	133,652	128,490	262,142	134,884	129,693	264,577	134,448	128,918	263,366
50-54	129,705	133,240	262,945	127,513	130,255	257,768	125,993	127,435	253,428	124,871	125,024	249,895	125,433	124,241	249,674
55-59	132,955	141,864	274,818	133,467	142,232	275,699	132,887	141,706	274,593	131,912	140,580	272,492	131,306	139,089	270,395
60-64	129,965	139,322	269,287	132,351	141,958	274,308	133,849	143,676	277,525	134,533	143,942	278,475	133,542	143,274	276,816
65-69	109,607	117,291	226,898	116,448	124,622	241,070	118,723	127,062	245,784	121,261	130,698	251,959	124,125	134,646	258,771
70-74	74,699	82,391	157,090	77,481	85,449	162,930	85,113	93,387	178,501	91,013	99,582	190,595	96,355	104,771	201,126
75-79	48,559	56,020	104,579	50,924	58,611	109,535	53,640	61,917	115,557	57,852	66,343	124,195	61,480	70,473	131,953
80-84	31,622	40,767	72,390	32,411	40,881	73,291	33,477	41,496	74,974	34,928	42,704	77,632	36,777	44,447	81,224
85+	30,017	53,896	83,912	30,733	54,244	84,977	31,299	54,294	85,593	32,001	54,359	86,360	32,638	54,310	86,948
Total	1,984,624	2,015,949	4,000,572	2,015,705	2,044,598	4,060,302	2,047,636	2,074,561	4,122,197	2,074,449	2,099,067	4,173,516	2,094,444	2,117,302	4,211,746
Mdn. Age	38.1	40.2	39.1	38.2	40.3	39.2	38.3	40.3	39.3	38.5	40.4	39.4	38.8	40.6	39.6

		2020			2021			2022			2023			2024	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	113,237	106,915	220,152	109,329	103,425	212,754	106,609	100,870	207,479	105,304	99,580	204,884	104,745	98,977	203,722
5- 9	123,860	115,371	239,231	123,953	115,423	239,376	123,603	115,188	238,791	122,111	113,939	236,050	119,923	112,033	231,956
10-14	128,130	121,823	249,953	127,613	120,992	248,606	126,739	119,473	246,211	125,937	118,076	244,013	125,669	117,794	243,463
15-19	127,382	121,070	248,452	127,258	120,727	247,985	128,435	122,236	250,671	130,045	123,656	253,702	130,997	123,830	254,827
20-24	137,058	131,433	268,491	135,862	130,295	266,157	135,329	129,238	264,567	135,111	129,282	264,392	135,029	129,777	264,806
25-29	153,083	153,520	306,602	150,247	149,594	299,840	148,723	147,855	296,578	147,911	146,826	294,737	148,156	146,662	294,817
30-34	151,655	150,605	302,260	155,087	155,438	310,525	159,098	160,072	319,171	162,610	163,276	325,885	164,226	164,693	328,920
35-39	148,069	142,075	290,145	149,168	143,168	292,336	149,904	144,159	294,063	150,833	145,892	296,725	153,300	149,013	302,313
40-44	138,401	132,923	271,324	141,104	135,530	276,634	144,231	138,553	282,784	146,578	140,667	287,245	149,617	143,263	292,880
45-49	133,046	127,280	260,326	131,111	125,703	256,814	131,599	126,542	258,140	134,587	128,818	263,405	136,838	131,044	267,882
50-54	128,012	125,946	253,958	131,479	128,435	259,914	133,702	129,890	263,593	134,557	130,925	265,482	134,096	130,256	264,351
55-59	129,342	135,990	265,333	126,428	131,996	258,424	124,503	128,641	253,144	123,329	125,969	249,298	124,017	125,285	249,302
60-64	132,996	143,122	276,118	132,369	142,561	274,930	131,190	141,475	272,665	129,900	139,982	269,882	129,416	138,516	267,933
65-69	126,431	137,112	263,544	127,783	138,939	266,723	128,670	140,064	268,734	128,991	140,103	269,093	128,078	139,541	267,619
70-74	102,180	111,312	213,492	107,836	117,755	225,591	109,520	119,749	229,269	111,604	123,053	234,657	114,257	126,788	241,044
75-79	64,557	73,994	138,552	66,651	76,473	143,124	73,160	83,466	156,627	78,300	89,081	167,381	82,945	93,809	176,754
80-84	38,523	46,040	84,563	40,086	48,066	88,153	42,075	50,727	92,802	45,407	54,439	99,846	48,370	57,913	106,283
85+	33,566	54,472	88,038	34,144	54,670	88,813	34,982	55,229	90,211	36,157	56,265	92,422	37,728	57,700	95,427
Total	2,109,529	2,131,006	4,240,535	2,117,508	2,139,192	4,256,700	2,132,074	2,153,426	4,285,500	2,149,272	2,169,829	4,319,100	2,167,406	2,186,893	4,354,300
Mdn. Age	39.0	40.8	39.9	39.3	41.1	40.2	39.6	41.3	40.4	39.8	41.5	40.7	40.1	41.8	40.9

		2025			2026			2027			2028			2029	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	105,176	99,313	204,489	106,340	100,358	206,698	107,501	101,416	208,917	108,455	102,286	210,741	109,151	102,919	212,070
5- 9	117,002	109,381	226,383	113,568	106,153	219,721	110,961	103,644	214,605	109,716	102,368	212,084	109,222	101,780	211,002
10-14	125,707	117,818	243,525	126,113	118,232	244,346	125,850	118,114	243,965	124,362	116,887	241,250	122,156	114,966	237,122
15-19	131,874	123,978	255,852	131,712	123,373	255,085	130,950	121,895	252,845	130,187	120,485	250,671	129,945	120,200	250,145
20-24	134,393	129,847	264,240	135,088	130,247	265,335	136,642	132,182	268,824	138,517	133,895	272,412	139,642	134,236	273,877
25-29	148,983	147,144	296,127	149,293	148,018	297,311	149,337	147,659	296,996	149,438	148,168	297,606	149,583	149,071	298,655
30-34	164,142	164,186	328,329	162,933	161,950	324,882	161,971	160,813	322,784	161,448	160,062	321,510	161,985	160,151	322,136
35-39	156,486	153,096	309,582	161,108	158,642	319,750	165,635	163,545	329,180	169,419	166,847	336,266	171,181	168,302	339,483
40-44	151,154	144,546	295,700	152,870	146,021	298,891	153,857	147,170	301,027	154,932	149,006	303,938	157,551	152,233	309,784
45-49	140,402	134,145	274,547	143,739	137,150	280,889	147,168	140,346	287,514	149,693	142,550	292,243	152,887	145,226	298,113
50-54	132,931	128,882	261,814	131,515	127,722	259,237	132,225	128,756	260,981	135,339	131,173	266,512	137,673	133,518	271,191
55-59	126,802	127,314	254,115	130,645	130,384	261,029	133,065	132,100	265,165	134,049	133,285	267,334	133,694	132,706	266,400
60-64	127,876	135,720	263,596	125,699	132,311	258,009	124,113	129,180	253,293	123,129	126,629	249,758	123,969	126,061	250,030
65-69	127,880	139,702	267,582	127,981	139,675	267,656	127,186	138,841	266,026	126,123	137,498	263,621	125,785	136,143	261,929
70-74	116,640	129,306	245,946	118,462	131,416	249,878	119,609	132,667	252,276	120,088	132,817	252,906	119,367	132,367	251,733
75-79	88,053	99,812	187,866	93,183	105,767	198,950	94,943	107,783	202,726	96,941	110,906	207,847	99,385	114,351	213,735
80-84	50,982	60,923	111,906	52,962	63,138	116,100	58,532	69,213	127,745	62,938	74,044	136,983	66,842	78,051	144,893
85+	39,438	59,163	98,601	41,187	61,045	102,232	43,248	63,486	106,734	46,237	66,781	113,018	49,034	69,968	119,002
Total	2,185,924	2,204,275	4,390,200	2,204,400	2,221,600	4,426,000	2,222,794	2,238,806	4,461,600	2,241,013	2,255,687	4,496,700	2,259,051	2,272,248	4,531,300
Mdn. Age	40.3	42.0	41.1	40.5	42.2	41.3	40.7	42.4	41.5	40.9	42.6	41.7	41.1	42.7	41.9

Table C.3 Population of Oregon: 1990-2029

Year (July 1)	Total Population	Change from previous year Number	Percent
1990	2,860,400	-	-
1991	2,928,500	68,100	2.38%
1992	2,991,800	63,300	2.16%
1993	3,060,400	68,600	2.29%
1994	3,121,300	60,900	1.99%
1995	3,184,400	63,100	2.02%
1996	3,247,100	62,700	1.97%
1997	3,304,300	57,200	1.76%
1998	3,352,400	48,100	1.46%
1999	3,393,900	41,500	1.24%
2000	3,431,100	37,200	1.10%
2001	3,470,400	39,300	1.15%
2002	3,502,600	32,200	0.93%
2003	3,538,600	36,000	1.03%
2004	3,578,900	40,300	1.14%
2005	3,626,900	48,000	1.34%
2006	3,685,200	58,300	1.61%
2007	3,739,400	54,200	1.47%
2008	3,784,200	44,800	1.20%
2009	3,815,800	31,600	0.84%
2010	3,837,300	21,500	0.56%
2011	3,854,587	17,287	0.45%
2012	3,878,223	23,636	0.61%
2013	3,910,991	32,768	0.84%
2014	3,952,098	41,107	1.05%
2015	4,000,572	48,474	1.23%
2016	4,060,302	59,730	1.49%
2017	4,122,197	61,895	1.52%
2018	4,173,516	51,319	1.24%
2019	4,211,746	38,230	0.92%
2020	4,240,535	28,788	0.68%
2021	4,256,700	16,165	0.38%
2022	4,285,500	28,800	0.68%
2023	4,319,100	33,600	0.78%
2024	4,354,300	35,199	0.81%
2025	4,390,200	35,900	0.82%
2026	4,426,000	35,800	0.82%
2027	4,461,600	35,601	0.80%
2028	4,496,700	35,100	0.79%
2029	4,531,300	34,600	0.77%

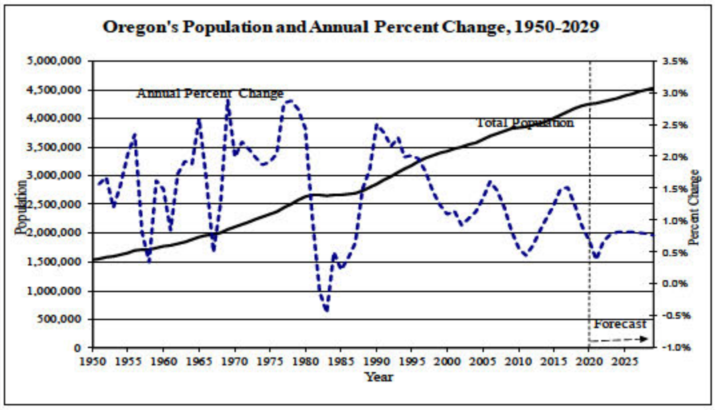


Table C.4 Children: Ages 0-4

Table C.5 School Age Population: Ages 5-17

Table C.6 Young Adult Population: Ages 18-24

Year (July 1)	C.4 Population	C.4 % Change from previous decade/yr. Number	C.4 Percent	C.5 Population	C.5 % Change from previous decade/yr. Number	C.5 Percent	C.6 Population	C.6 % Change from previous decade/yr. Number	C.6 Percent
1980	199,525	---	---	524,446	---	---	329,407	---	---
1990	209,638	10,113	5.07%	532,727	8,281	1.58%	268,134	-61,273	-18.60%
2000	223,207	13,569	6.47%	624,316	91,589	17.19%	330,328	62,194	23.20%
2001	224,645	1,438	0.64%	624,675	358	0.06%	336,660	6,333	1.92%
2002	225,084	439	0.20%	624,611	-64	-0.01%	340,778	4,118	1.22%
2003	226,652	1,568	0.70%	624,349	-262	-0.04%	345,266	4,487	1.32%
2004	228,353	1,701	0.75%	625,461	1,112	0.18%	349,138	3,873	1.12%
2005	230,008	1,655	0.72%	628,326	2,865	0.46%	351,076	1,938	0.55%
2006	231,882	1,874	0.81%	633,646	5,320	0.85%	354,328	3,252	0.93%
2007	236,160	4,278	1.85%	635,720	2,074	0.33%	356,311	1,983	0.56%
2008	239,340	3,180	1.35%	635,372	-348	-0.05%	358,967	2,656	0.75%
2009	239,929	589	0.25%	633,575	-1,797	-0.28%	360,134	1,166	0.32%
2010	238,457	-1,472	-0.61%	630,741	-2,835	-0.45%	359,764	-370	-0.10%
2011	236,013	-2,444	-1.02%	628,068	-2,673	-0.42%	360,113	349	0.10%
2012	232,609	-3,404	-1.44%	628,150	83	0.01%	361,636	1,523	0.42%
2013	229,809	-2,800	-1.20%	629,372	1,222	0.19%	364,649	3,013	0.83%
2014	228,996	-813	-0.35%	630,694	1,322	0.21%	366,969	2,319	0.64%
2015	229,234	238	0.10%	631,954	1,260	0.20%	368,388	1,420	0.39%
2016	230,866	1,632	0.71%	633,847	1,893	0.30%	368,929	540	0.15%
2017	231,847	981	0.42%	636,135	2,288	0.36%	370,969	2,040	0.55%
2018	229,931	-1,915	-0.83%	636,107	-28	0.00%	372,630	1,661	0.45%
2019	225,977	-3,955	-1.72%	636,303	196	0.03%	371,902	-728	-0.20%
2020	220,152	-5,825	-2.58%	637,133	830	0.13%	368,994	-2,908	-0.78%
2021	212,754	-7,398	-3.36%	636,935	-198	-0.03%	365,189	-3,805	-1.03%
2022	207,479	-5,275	-2.48%	635,677	-1,259	-0.20%	364,563	-626	-0.17%
2023	204,884	-2,595	-1.25%	633,024	-2,652	-0.42%	365,132	569	0.16%
2024	203,722	-1,162	-0.57%	628,845	-4,179	-0.66%	366,207	1,075	0.29%
2025	204,489	767	0.38%	622,180	-6,666	-1.06%	367,821	1,614	0.44%
2026	206,698	2,208	1.08%	614,041	-8,139	-1.31%	370,446	2,625	0.71%
2027	208,917	2,219	1.07%	607,067	-6,974	-1.14%	373,171	2,725	0.74%
2028	210,741	1,824	0.87%	601,049	-6,018	-0.99%	375,368	2,198	0.59%
2029	212,070	1,329	0.63%	596,633	-4,416	-0.73%	375,513	145	0.04%

Table C.7 Criminally At Risk Population (males): Ages 15-39

Year (July 1)	Population	% Change from previous decade/yr. Number	Percent
1980	561,931	---	---
1990	544,738	-17,193	-3.06%
2000	616,988	72,250	13.26%
2001	618,906	1,918	0.31%
2002	620,252	1,347	0.22%
2003	622,211	1,959	0.32%
2004	626,423	4,212	0.68%
2005	633,901	7,478	1.19%
2006	644,210	10,309	1.63%
2007	652,287	8,077	1.25%
2008	657,248	4,961	0.76%
2009	657,327	79	0.01%
2010	653,491	-3,836	-0.58%
2011	651,542	-1,950	-0.30%
2012	653,021	1,479	0.23%
2013	658,242	5,221	0.80%
2014	666,045	7,803	1.19%
2015	675,376	9,331	1.40%
2016	687,491	12,115	1.79%
2017	700,030	12,540	1.82%
2018	708,851	8,821	1.26%
2019	715,385	6,533	0.92%
2020	717,247	1,863	0.26%
2021	717,622	374	0.05%
2022	721,490	3,868	0.54%
2023	726,510	5,020	0.70%
2024	731,708	5,198	0.72%
2025	735,879	4,171	0.57%
2026	740,133	4,254	0.58%
2027	744,536	4,402	0.59%
2028	749,008	4,473	0.60%
2029	752,335	3,327	0.44%

Table C.8 Prime Wage Earners: Ages 25-44

Year (July 1)	Population	% Change from previous decade/yr. Number	Percent
1980	790,750	---	---
1990	926,326	135,576	17.15%
2000	996,500	70,174	7.58%
2001	994,587	-1,913	-0.19%
2002	989,996	-4,591	-0.46%
2003	987,755	-2,241	-0.23%
2004	988,932	1,177	0.12%
2005	994,575	5,644	0.57%
2006	1,004,110	9,535	0.96%
2007	1,014,565	10,455	1.04%
2008	1,022,060	7,495	0.74%
2009	1,024,971	2,911	0.28%
2010	1,026,126	1,155	0.11%
2011	1,029,254	3,128	0.30%
2012	1,034,895	5,641	0.55%
2013	1,043,933	9,038	0.87%
2014	1,055,408	11,475	1.10%
2015	1,069,027	13,619	1.29%
2016	1,089,734	20,707	1.94%
2017	1,115,151	25,417	2.33%
2018	1,138,670	23,519	2.11%
2019	1,157,292	18,622	1.64%
2020	1,170,331	13,039	1.13%
2021	1,179,336	9,005	0.77%
2022	1,192,596	13,260	1.12%
2023	1,204,593	11,996	1.01%
2024	1,218,930	14,337	1.19%
2025	1,229,738	10,808	0.89%
2026	1,240,834	11,096	0.90%
2027	1,249,986	9,152	0.74%
2028	1,259,319	9,333	0.75%
2029	1,270,058	10,738	0.85%

Table C.9 Older Wage Earners: Ages 45-64

Year (July 1)	Population	% Change from previous decade/yr. Number	Percent
1980	491,249	---	---
1990	531,181	39,932	8.13%
2000	817,510	286,329	53.90%
2001	847,276	29,766	3.64%
2002	876,242	28,966	3.42%
2003	903,499	27,257	3.11%
2004	930,032	26,533	2.94%
2005	957,826	27,793	2.99%
2006	985,638	27,813	2.90%
2007	1,008,986	23,348	2.37%
2008	1,025,501	16,515	1.64%
2009	1,039,689	14,188	1.38%
2010	1,050,150	10,461	1.01%
2011	1,056,657	6,507	0.62%
2012	1,051,850	-4,807	-0.45%
2013	1,048,902	-2,948	-0.28%
2014	1,051,321	2,418	0.23%
2015	1,057,101	5,780	0.55%
2016	1,065,125	8,024	0.76%
2017	1,067,688	2,563	0.24%
2018	1,065,439	-2,249	-0.21%
2019	1,060,251	-5,188	-0.49%
2020	1,055,735	-4,515	-0.43%
2021	1,050,082	-5,654	-0.54%
2022	1,047,542	-2,540	-0.24%
2023	1,048,068	526	0.05%
2024	1,049,468	1,400	0.13%
2025	1,054,072	4,604	0.44%
2026	1,059,165	5,093	0.48%
2027	1,066,952	7,787	0.74%
2028	1,075,847	8,895	0.83%
2029	1,085,733	9,886	0.92%

Table C.10 Elderly Population by Age Group

Year (July 1)	Ages 65+	%Change from previous decade/yr.	Ages 65-74	%Change from previous decade/yr.	Ages 75-84	%Change from previous decade/yr.	Ages 85+	%Change from previous decade/yr.
1980	305,841	---	185,863	---	91,137	---	28,841	---
1990	392,369	28.29%	224,772	20.93%	128,813	41.34%	38,784	34.48%
2000	439,239	11.95%	218,997	-2.57%	162,187	25.91%	58,055	49.69%
2001	442,558	0.76%	218,838	-0.07%	163,878	1.04%	59,843	3.08%
2002	445,890	0.75%	219,614	0.35%	165,109	0.75%	61,167	2.21%
2003	451,080	1.16%	222,361	1.25%	165,669	0.34%	63,050	3.08%
2004	456,984	1.31%	226,373	1.80%	165,842	0.10%	64,769	2.73%
2005	465,089	1.77%	231,926	2.45%	166,077	0.14%	67,087	3.58%
2006	475,596	2.26%	239,931	3.45%	165,787	-0.17%	69,877	4.16%
2007	487,657	2.54%	250,131	4.25%	165,148	-0.39%	72,379	3.58%
2008	502,959	3.14%	264,201	5.63%	164,354	-0.48%	74,403	2.80%
2009	517,502	2.89%	277,606	5.07%	163,513	-0.51%	76,383	2.66%
2010	532,062	2.81%	289,645	4.34%	164,159	0.40%	78,258	2.45%
2011	544,482	2.33%	300,272	3.67%	164,357	0.12%	79,852	2.04%
2012	569,082	4.52%	322,222	7.31%	165,631	0.77%	81,230	1.73%
2013	594,325	4.44%	343,690	6.66%	168,177	1.54%	82,458	1.51%
2014	618,710	4.10%	363,178	5.67%	172,230	2.41%	83,302	1.02%
2015	644,869	4.23%	383,988	5.73%	176,968	2.75%	83,912	0.73%
2016	671,802	4.18%	404,000	5.21%	182,826	3.31%	84,977	1.27%
2017	700,408	4.26%	424,285	5.02%	190,531	4.21%	85,593	0.72%
2018	730,740	4.33%	442,554	4.31%	201,827	5.93%	86,360	0.90%
2019	760,022	4.01%	459,897	3.92%	213,177	5.62%	86,948	0.68%
2020	788,188	3.71%	477,035	3.73%	223,115	4.66%	88,038	1.25%
2021	812,404	3.07%	492,314	3.20%	231,277	3.66%	88,813	0.88%
2022	837,643	3.11%	498,003	1.16%	249,429	7.85%	90,211	1.57%
2023	863,399	3.07%	503,750	1.15%	267,227	7.14%	92,422	2.45%
2024	887,127	2.75%	508,664	0.98%	283,036	5.92%	95,427	3.25%
2025	911,900	2.79%	513,528	0.96%	299,771	5.91%	98,601	3.33%
2026	934,816	2.51%	517,534	0.78%	315,050	5.10%	102,232	3.68%
2027	955,507	2.21%	518,302	0.15%	330,471	4.89%	106,734	4.40%
2028	974,375	1.97%	516,527	-0.34%	344,830	4.34%	113,018	5.89%
2029	991,293	1.74%	513,662	-0.55%	358,629	4.00%	119,002	5.29%

Oregon Economic and Revenue Forecast

Kate Brown
GOVERNOR

December 2021

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Foreword

This document contains the Oregon economic and revenue forecasts. The Oregon economic forecast is published to provide information to planners and policy makers in state agencies and private organizations for use in their decision making processes. The Oregon revenue forecast is published to open the revenue forecasting process to public review. It is the basis for much of the budgeting in state government.

The report is issued four times a year; in March, June, September, and December.

The economic model assumptions and results are reviewed by the Department of Administrative Services Economic Advisory Committee and by the Governor's Council of Economic Advisors. The Department of Administrative Services Economic Advisory Committee consists of 15 economists employed by state agencies, while the Governor's Council of Economic Advisors is a group of 12 economists from academia, finance, utilities, and industry.

Members of the Economic Advisory Committee and the Governor's Council of Economic Advisors provide a two-way flow of information. The Department of Administrative Services makes preliminary forecasts and receives feedback on the reasonableness of such forecasts and assumptions employed. After the discussion of the preliminary forecast, the Department of Administrative Services makes a final forecast using the suggestions and comments made by the two reviewing committees.

The results from the economic model are in turn used to provide a preliminary forecast for state tax revenues. The preliminary results are reviewed by the Council of Revenue Forecast Advisors. The Council of Revenue Forecast Advisors consists of 15 specialists with backgrounds in accounting, financial planning, and economics. Members bring specific specialties in tax issues and represent private practices, accounting firms, corporations, government (Oregon Department of Revenue and Legislative Revenue Office), and the Governor's Council of Economic Advisors. After discussion of the preliminary revenue forecast, the Department of Administrative Services makes the final revenue forecast using the suggestions and comments made by the reviewing committee.

Readers who have questions or wish to submit suggestions may contact the Office of Economic Analysis by telephone at 503-378-3405.

Katy Coba

Katy Coba
DAS Director
Chief Operating Officer

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EXECUTIVE SUMMARY

December 2021

The economic recovery from the pandemic continues to be robust. Booming wage gains are now offsetting the fading federal aid. Household incomes and consumer spending remain strong, supporting an overall bright outlook. The economy is set to reach full employment a year from now, or three times faster than in the aftermath of the Great Recession.

The fundamental economic challenge remains the supply side of the economy trying to keep pace with demand. Labor runs through everything, from production to logistics to sales. Firms are looking to hire as quickly as possible, while labor supply has been slower to recover. Labor shortages are likely to ease some in the coming months as more workers search for a job in earnest. Even so, the labor market will remain tight for structural reasons like more retirements and less immigration.

In a supply-constrained economy real economic growth is challenging. Firms invest in new technologies to raise productivity, but this takes time. Persistent inflation is a risk. The Federal Reserve, and many private forecasters, expect inflation to cool some as the impacts of reopening the economy fade and supply chain struggles ease. While not the baseline outlook, the ultimate risk is that the economy runs too hot and the Fed raises rates sharply, creating a boom/bust dynamic in the years ahead instead of engineering the expected soft landing.

Recent forecasts have called for tax collections to return to earth. Federal aid has expired, and economic activity is beginning to return to normal with workers reentering the labor force, returning to offices and spending more on services. Instead of normalizing, however, revenue growth has accelerated further. In recent weeks, daily collection records have been set for both personal income tax withholdings and corporate tax collections. In addition, Lottery sales continue to set records for this time of year.

The revenue boom is being supported by a wide range of income sources. Most importantly, healthy gains in labor income are generating personal income tax payments. Despite Oregon having 70,000 fewer jobs relative to pre-pandemic levels, taxable wages and salaries are far above pre-pandemic trends. A persistently tight labor market is putting upward pressure on wages, leading to significant payroll growth despite the job losses.

The return of inflation after a 30-year hiatus is also generating additional revenue across a range of tax instruments. With demand so strong across the economy, businesses currently have a considerable amount of pricing power, and have been able to pass most of their cost increases along to consumers. As a result, profits and other taxable business incomes are booming. In addition to the direct boost to tax collections, healthy business earnings are supporting equity markets and other forms of investment income.

Inflation is also generating additional Corporate Activity Tax collections. Business sales are taxed by value, not by the quantity sold. As a result, tax liability has risen along with prices, and is expected to remain higher throughout the forecast horizon.

The recent revenue boom, together with an improving outlook for labor earnings, have led to a significant upward revision to the outlook for personal and corporate income tax collections. The current forecast now projects both a $558 million personal income tax kicker, and a $250 million corporate kicker as the forecasts have been raised more than 2 percent since the Close of Session. However, considerable uncertainty remains. Although the baseline outlook calls for continued growth, overheating remains a real possibility. Inflationary booms of the sort we are experiencing today traditionally do not end well, putting recent revenue gains at risk going forward.

ECONOMIC OUTLOOK

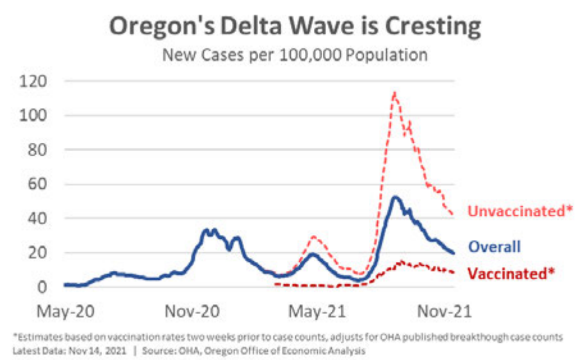
The economic recovery from the pandemic continues to be robust. Booming wage gains are now offsetting the fading federal aid. Household incomes and consumer spending remain strong, supporting an overall bright outlook. The economy is set to reach full employment a year from now, or three times faster than in the aftermath of the Great Recession.

The fundamental economic challenge remains the supply side of the economy trying to keep pace with demand. Labor runs through everything, from production to logistics to sales. Firms are looking to hire as quickly as possible, while labor supply has been slower to recover. Labor shortages are likely to ease some in the coming months as more workers search for a job in earnest. Even so, the labor market will remain tight for structural reasons like more retirements and less immigration.

In a supply-constrained economy real economic growth is challenging. Firms invest in new technologies to raise productivity, but this takes time. Persistent inflation is a risk. The Federal Reserve, and many private forecasters, expect inflation to cool some as the impacts of reopening the economy fade and supply chain struggles ease. While not the baseline outlook, the ultimate risk is that the economy runs too hot and the Fed will raise interest rates sharply, creating a boom/bust dynamic in the years ahead instead of engineering a soft landing.

Pandemic Update

While new cases and hospitalization remain higher than at most points during the pandemic, the good news is the delta wave has crested. Economically, what matters the most are shutdowns. Without those in place, the economic impacts are contained to workplace disruptions with some workers out sick, and any slowing in consumer spending as some households stay home more.



With continued increases in vaccinations and available medical treatments, further pandemic progress is expected, boosting underlying economic growth. Pandemic-related risks are to the downside should public health deteriorate again in a future wave or new variant. Even so, the economic impacts are expected to be relatively minor compared to early in the pandemic.

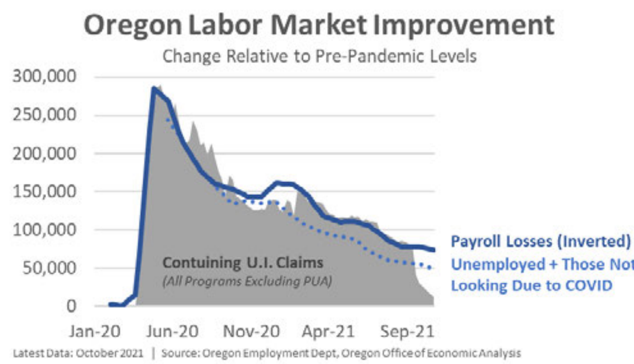
Supply Trying to Keep Pace with Demand

Consumer demand remains robust. Between rising incomes, accumulated savings, lower levels of debt, and record housing and stock markets, consumers have no shortage of firepower. The economic challenges remain on the supply side of the economy. As firms struggle to find enough workers to produce products, increase capacity, and get the goods to market, it means the economy cannot grow as quickly as demand alone would suggest. These dynamics result in slower real growth and higher prices. The overall outlook remains bright, but supply constraints mean the recovery may take a little longer than anticipated.

Labor is the biggest supply constraint today. The reason is labor runs through everything. If firms cannot find enough workers, then they cannot produce as many products, provide as much care, clean as many hotel rooms, or cook as many meals as consumers would like. Today, businesses are advertising a record number of job openings. Here in Oregon there are 106,000 such openings according to the latest Oregon Employment

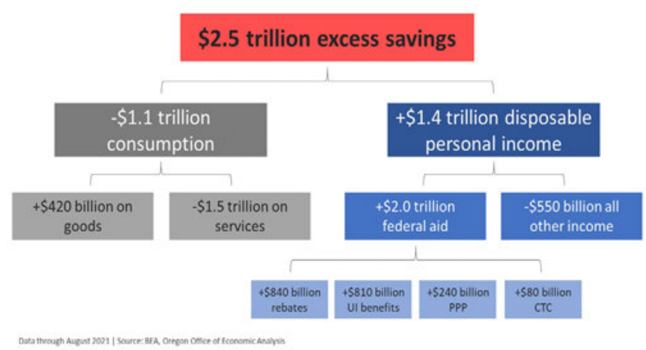
Department job vacancy survey, and 78% of them are difficult to fill. Unlike past cycles where job opportunities were few and far between, today labor demand is strong. There are considerably more job openings than job seekers.

One big piece to the labor puzzle has been the impact of federal aid. In particular, enhanced unemployment insurance benefits provided an average of 100% wage replacement this year to laid off workers. The wage replacement rate is considerably higher for lower-wage, and part-time workers as the $300 per week enhancement was given as a lump sum to all who qualified. Such policy is a financial disincentive for some, not all, but some individuals to return to work.



What is a newer labor market development is that the enhanced unemployment insurance benefits ended in early September. Throughout the pandemic, the increase in the number of Oregonians receiving UI mirrored overall employment patterns. As job growth picked up, the number of UI payments fell. This does not mean that job growth could not have been faster than experienced this year, however it also does not mean that the enhanced UI benefits were some immovable force immune to broader changes in the labor market. That said, with the enhanced benefits expiring this fall, there is now a clear, temporary gap between the total number of Oregonians receiving UI and the total number of jobs in the state. As of October, Oregon has 73,000 jobs left to go to reach pre-pandemic employment levels. Conversely, there are only about 10,000 more Oregonians receiving UI than before the pandemic hit.

Expectations are that workers will return to the labor market in greater numbers in the months ahead, easing the labor constraints somewhat. That said, our office continues to believe that what matters most for labor supply is not just UI, but total household incomes and their budget needs. UI was a big piece to the overall puzzle, but not the only piece.



At the U.S. level, households have $2.5 trillion in excess savings since the start of the pandemic. 42 percent of this can be tied to less consumer spending in 2020 as households did not go out to eat, have elective surgeries performed, or go on vacations to the same degree as in years past. Consumer spending has reverted to trend in 2021 and is no longer a contributing factor to rising household savings.

58 percent of the excess household savings is due to higher incomes during the pandemic. Income gains are entirely thanks to the various federal programs enacted, as incomes excluding this aid declined during the shutdowns and recession. Recovery rebates, unemployment insurance, paycheck protection program grants, the enhanced child tax credit, and other programs more than offset the direct financial losses of the pandemic.

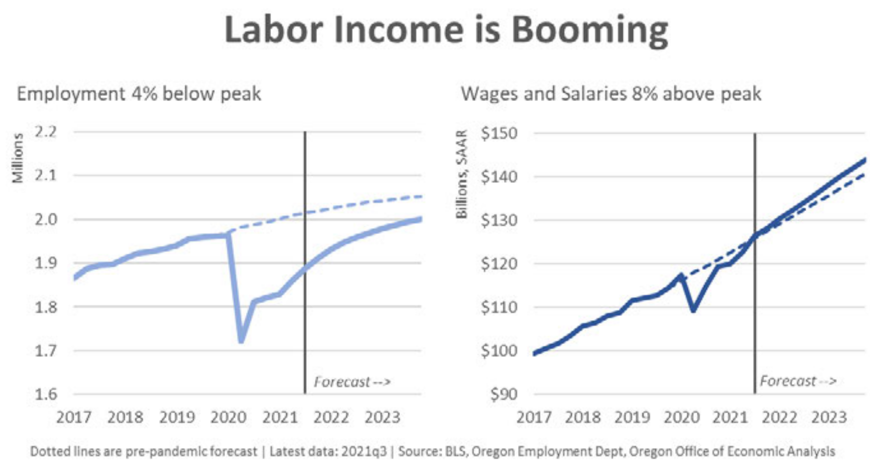
As households spend down some of this excess savings, the need to work to pay bills and put food on the table will increase. Additionally, as job opportunities become more plentiful and higher paying, workers will be enticed to return to work in greater numbers. Again, there are many more job openings than job seekers today.

The ultimate question is when will this happen? Initially, our office expected this to really begin in earnest late this year. There is some indication it may take a bit longer, and be more of a steady stream rather than a sudden rush. Labor supply risks are to the downside.

The job posting site Indeed asks individuals why they are not urgently searching for jobs[1]. In recent months the top reason why has shifted from pandemic fears during the delta wave, to financial cushion, to spousal employment. This pattern makes intuitive sense, and highlights an important labor market development in recent quarters.

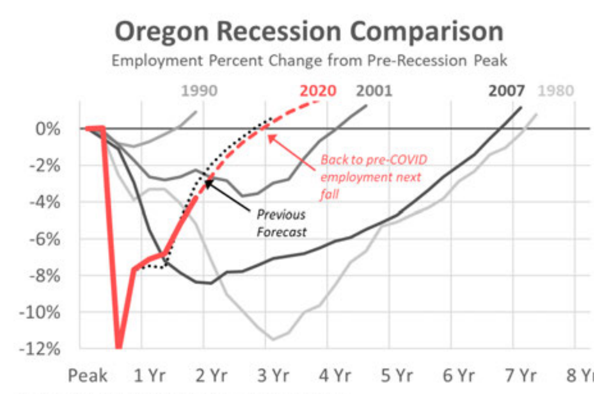
Labor income is booming

Today in Oregon, employment is 4 percent below pre-pandemic levels, and 6 percent below trend. There remains a massive jobs hole left to fill. However, total wages and salaries earned in the economy are 8 percent above pre-pandemic levels. Wages have fully reverted to trend, and will soon surpass pre-pandemic expectations. Employees are working more hours and at higher pay. Average wages in Oregon are 15 percent higher today than before the pandemic. This matters for a few reasons.



First, businesses' labor costs have never been higher. They are paying more total labor costs, despite having fewer employees. To the extent productivity gains are similarly strong, this is of no concern. To the extent a higher wage bill needs to be passed along to consumers, this can be a key part of broader inflation. And to the extent higher costs cannot be pushed forward onto consumers, it means firm profitability or other costs need to be reduced, at least on the margin. In a strong sales environment, total revenues are rising, so these changes are relative costs and not outright declines.

Second, strong wage gains among current workers can slow the return of some individuals thinking of coming back into the labor market. This is particularly the case for families, or more broadly for households with multiple adults. Between the excess household savings, and strong income gains for the current earner, a second adult does not need to return to work as quickly to pay the bills, especially if there is any other concern related to the pandemic, childcare, or the like.



Overall the economic and labor outlook remain bright. The current economic recovery is much faster than experienced in recent business cycles. However, supply constraints remain. The employment outlook this forecast is slowed a hair, as labor supply is expected to take a little

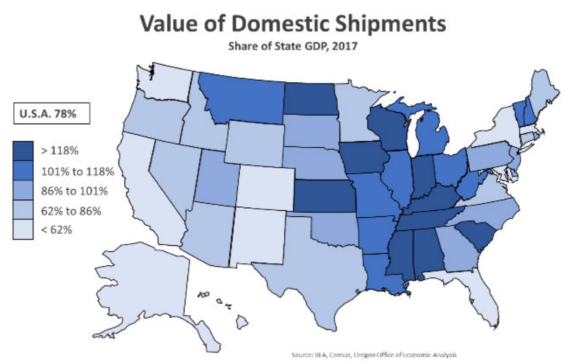
[1] https://www.hiringlab.org/2021/10/12/job-search-survey-september-2021/

longer to recover than previously anticipated. Oregon is now expected to fully regain all of it's pandemic-related lost jobs by next fall, or one quarter slower than in the previous forecast. The economy is still expected to reach full employment by early 2023.

Supply Chains Struggle

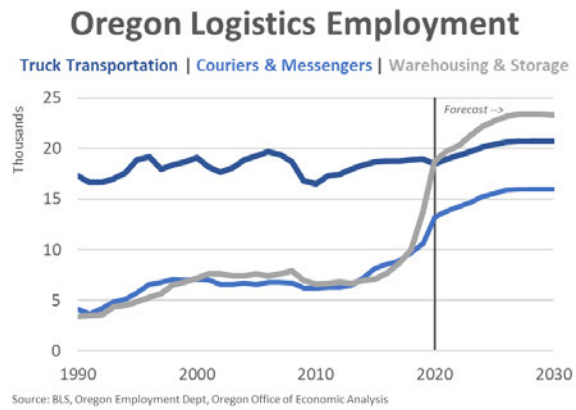
There is no question that global supply chains are struggling today. Between bare shelves, delayed orders, and rising prices, supply bottlenecks are evident across the economy. The primary reason is not just that COVID is keeping some workers home sick, or that factories and warehouses are operating at or near capacity, which they are. No, the primary reason is consumer incomes and demand are very high. This is particularly true for physical goods, where spending is 15 percent above trend and expected to remain elevated throughout next year, if not longer. Even after adjusting for inflation, goods spending is still 9 percent above trend today. It is important to note that current supply chains are moving record volumes of products, but just not as many as consumers would like to buy.

The good news is Oregon has less direct exposure than most states to these supply chain problems. Oregon manufacturers rely on imported intermediate goods less than most states. This is largely because both the wood products and food manufacturing subsectors use locally sourced raw materials. Plus the state's high-tech sector does most of the value-added work locally, in turning raw materials into silicon wafers and the like. Additionally, the movement of freight – the value of shipments relative to the size of the economy – is relatively smaller in Oregon than in many other states. Combined, this means the supply chain problems disrupt a somewhat smaller slice of the regional economy than is the case elsewhere in the country.



Unfortunately, even as Oregon may have less direct exposure, the state is not immune. Global supply chains impact everything. Slowdowns at ports in southern California, and backups in rail yards in the Midwest impact the ability of Oregon firms to get the supplies they need, and for Oregonians to buy products at the store. Supply chain problems are a macro constraint impacting all parts of the economy today.

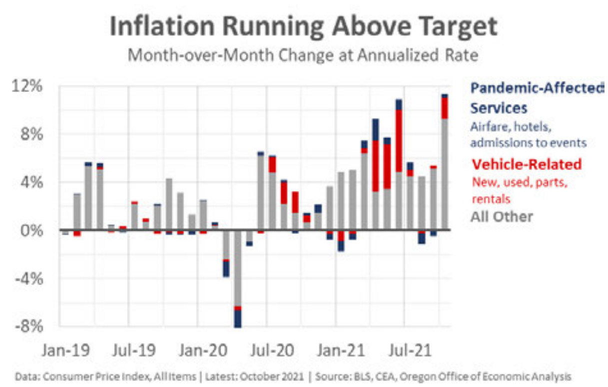
Looking forward there are a few potential avenues for improvements. First, as the pandemic wanes, more workers can return to their jobs, improving production and the movement of goods within existing supply chains. Second, firms can increase their productive capacity to meet the strong demand. Not only would this boost economic growth, but a supply increase can also slow inflationary pressures. Included here is added trucking capacity. The vast majority of freight moves on trucks. Third, while not in the baseline outlook, a cooling in consumer demand would immediately relieve pressure on supply chains.



Here in Oregon, supply chain-related employment is growing and well above 2019 or pre-pandemic levels. Much of the growth is seen in warehousing and storage jobs as more distribution centers have and will continue to open. That said, trucking is growing as well. This is true for both long-haul (truck transportation) and last mile delivery (couriers and messengers). The outlook calls for ongoing gains in these sectors, albeit slower growth than experienced in recent years. The primary reason is that much of the growth in consumer spending in the year ahead will be in services, including more in-store shopping, with slower gains likely in goods and potentially even e-commerce.

Persistent Inflation is a Risk

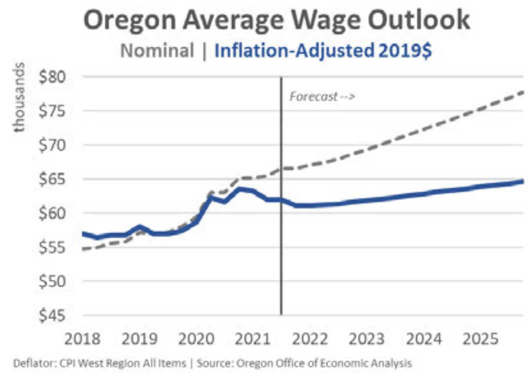
An economy where demand is very strong and supply is constrained is a classic recipe for rising prices. Inflation is running hot, and showing no real signs of letting up in the near term. Initially, much of the inflation could be directly tied to reopening sectors of the economy, and shortages in the automobile industry. However, inflationary pressures seem to be widening beyond these temporary issues. Persistent inflation is a moderate risk to the overall outlook.



The Federal Reserve will look through temporary bouts of inflation, particularly as they work to meet their dual mandate of maximum employment and price stability. The Fed is actively communicating that they will run the economy hot to ensure maximum employment, even as it may result in higher inflation than experienced in recent cycles. This is especially true if the underlying belief is longer-run inflation remains well anchored. Recently Chairman Powell acknowledged he expected inflation will remain hot well into next year and that by the second or third quarter the transitory, or temporary pressures may begin to ease.

Given monetary policy impacts the real economy with long and variable lags, the risk is higher inflation may last longer than expected. The Federal Reserve is not set to raise interest rates until the second half of next year, or even possibly early 2023. Even so, financial markets expect 2-3 rate hikes next year, which is more than the Fed itself is anticipating. That said, the Fed is adjusting their economic and inflation forecasts higher, meaning more, or sooner rate hikes could be possible depending upon the exact path the economy takes. An underappreciated view is that the strong labor market recovery may mean the Fed meets its dual mandate – both employment and inflation – by the middle of next year, thus beginning to increase interest rates a little sooner than anticipated.

In the meantime, inflation is impacting the real economy in a few ways. First, higher prices are eating into household budgets. Normally, a faster increase in the cost of living impacts lower-income households to a greater degree as they live paycheck to paycheck. Rising prices therefore impact every dollar earned.



Second, higher prices are also eating into the strong wage gains workers are experiencing. While the average wage in Oregon is up 15 percent since the start of the pandemic, the real, or inflation-adjusted average wage is up 8 percent. Clearly those are still solid gains over the entire period, however as seen in the nearby chart, inflation is beginning to impact real wages much more in recent quarters.

Should inflation considerations become a more regular part of wage negotiations, it can lead to more cost-push inflationary pressures in the broader economy. What matters most for workers and households are real wage gains, which are not expected to pick up again in the current outlook until late next year as inflationary pressures subside.

Even so, wages are rising fastest among low-wage workers throughout the pandemic. After adjusting for inflation, workers earning less than $20 per hour are seeing real wage gains and an overall increase in their standard of living. On the other hand, middle- and high-wage workers are, on average, still earning wage gains, but those raises have not fully kept pace with inflation. One result of this wage compression is a reduction in overall wage inequality, which may or may not have some social or economic benefits even in a high inflation environment.

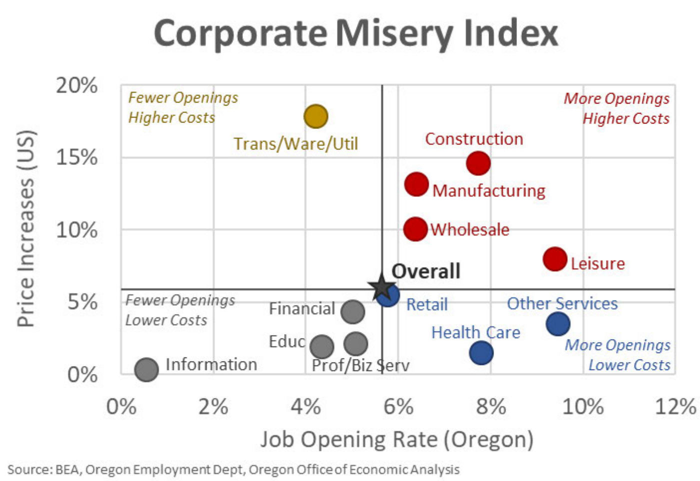
Third, as costs rise, firms face the decision to pass these costs forward onto consumers, contributing to overall inflation, or to reduce margins or other costs to help keep final prices lower. These adjustments take time, and are based in part on businesses' beliefs about the ability of consumers to absorb higher prices. Today, given incomes and demand, firms are passing along cost increases and profit margins have actually increased to be at or near record highs. Moving forward, at some point it is likely that rising labor costs will begin to reduce profit margins back down to their historical range. This will be disinflationary as final consumer prices increase at a lower rate than underlying costs. One key issue to watch here is demand destruction, or the impact of higher prices reducing the number of products sold as consumers are unwilling or unable to pay the higher prices.

Ultimately what matters is where inflation settles. Should inflation slow back to the 2-3 percent range then there is likely no real risk. Inflation that is slightly above the Fed's 2 percent target would be an interesting academic development, but unlikely to have any real implications for the economy. However inflation that remains higher for longer would ultimately see the Fed step in and raise interest rates faster than expected to cool the economy. Historically this usually means a recession and hard landing for the economy, rather than a continued expansion and soft landing. This would lead to a boom/bust cycle, which is modeled as an alternative scenario on page 15.

Corporate Misery

Most readers are likely familiar with the Misery Index, a calculation created by economist Arthur Okun in the 1960s. It's the sum of the rate of inflation and the unemployment rate. As such it's a relative gauge of how households are doing. While unemployment is declining today as the economy recovers, inflation has picked up, reversing the recent improvements in the standard misery index.

Today, between labor challenges and rising input costs, businesses are miserable as well. The Corporate Misery Index combines rising prices and the job opening rate to gauge the supply constraints firms are facing in the economy. Now, given the strong consumer demand, companies have been able to pass along their cost increases during the pandemic. Corporate profits are at record highs, which means they financially offset the day-to-day challenges of running a business, even as those challenges are larger than at any point in recent decades.



Digging into the data further reveals an interest pattern across sectors here in Oregon. In the nearby scatterplot, the horizontal axis shows the current job opening rate in Oregon. This gauges how many employees companies would like to hire, relative to the size of their existing workforce. The further an industry is to the right, the larger its current labor challenges. On the vertical axis is the increase in costs at the national level from various production and consumer price indices. Given available data the comparison is not perfectly aligned at the sector level but the results are intuitive and broadly in line with what firms in different sectors are saying.

In the upper-right corner are the sectors that are grappling with the largest increases in costs and the largest labor challenges. This includes goods-producing industries like construction and manufacturing, in addition to leisure and hospitality.

In the upper-left corner is transportation, warehousing, and utilities. The costs of logistics in terms of transportation and storage costs are rising rapidly. However the industry is not facing quite as large of labor challenges, likely in large part because the sector has been raising wages and experiencing really strong job growth already. These gains include drawing in workers from other sectors like retail, manufacturing, and construction.

In the lower-right corner are industries like health care and other services (repair shops, barbershops and nail salons) which are looking to hire a lot of workers today but are not currently facing as strong of price pressures as the economy overall. Finally in the lower-left corner are sectors where they are generally struggling with labor and cost challenges but to a lesser degree than most other industries.

Looking forward, businesses are likely to continue to struggle with day-to-day operations given labor challenges and cost pressures. The outlook calls for corporate misery to ease some in the quarters ahead as labor supply returns some and price pressures abate. However, it is likely corporate misery will remain higher in the years ahead than during the previous couple of decades. The real corporate struggles are still ahead and will be financial and operational in nature when they are no longer able to fully pass along their cost increases to consumers who are unwilling or unable to absorb them.

Federal Fiscal Policy

Congress is currently debating two major federal spending packages. Our office's macroeconomic vendor, IHS Markit, has now included the infrastructure package in the baseline economic outlook for the first time. The budget reconciliation package is not included in the baseline.

In terms of the economic impacts of the infrastructure bill, a few points stand out. Infrastructure typically boosts both near-term growth due to the increased economic activity, and long-term growth due to productivity gains. The specifics of how much Oregon will receive are still unknown. Many of the spending priorities – roads, bridges, rural broadband, etc – are likely to be distributed based on population. As such Oregon is likely to benefit as much as the average state. As more information is learned, our office will adjust the outlook accordingly.

More importantly for the near-term outlook is infrastructure usually takes time. The funds have to be allocated, then awarded, and then the actual spending and construction takes place. Earlier this year, the Congressional Budget Office modeled a similarly sized infrastructure package and found that the impacts start slow and build through years 3 or 4. IHS Markit estimates the peak economic impact of the infrastructure bill on GDP growth will be 0.2 percentage points in 2024, and temporarily increasing employment by 750,000 jobs in 2025. As such, much of the economic boost from infrastructure are outside the current 2021-23 biennium in Oregon.

What's Wrong with Portland?

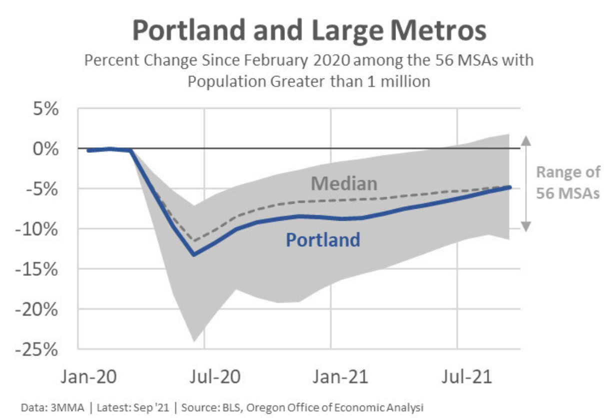
Large metro areas led the recovery coming out of the Great Recession. Portland's growth last decade was transformational. Among the 100 largest metros in the country, Portland ranked in the Top 10 for high-wage job growth, median household income gains, and increases in educational attainment. The region's urban core also transformed physically with numerous apartments, hotels, and offices being built, helping create an attractive place to live, work, and play.

This cycle is different. During a pandemic, urban amenities like walkable neighborhoods and clusters of knowledge workers turn into dis-amenities. Portland is now the worst performing regional economy in the state. The primary reason is the lack of in-person activities that cities normally thrive one. With more individuals working from home and business travel just now starting to pick up, urban cores to date are a shadow of their former selves. There just aren't as many individuals going out to eat, window shopping, or staying in hotels for work or leisure.

However, incomes and consumer spending remain strong. It's just more of that spending is occurring in suburban and rural areas as workers eat and shop closer to home. As seen above, the City of Portland is trailing the rest of the region and state in many in-person activities. Specifically, the number of people going out to eat is only halfway recovered, while it is fully recovered elsewhere in the state. Video lottery sales, a measure of consumer spending in bars and restaurants, are fully recovered in downtown Portland, but they are even stronger in the suburbs and rest of the state. As a result of fewer overall visits and trips into the City of Portland, leisure and hospitality employment remains depressed.

However, these general dynamics are not unique to Portland. Across the country, large urban areas with populations of at least one million residents are trailing their smaller urban and rural counterparts. In fact, economic data show that the Portland region is right in line with the experiences of these other big metros. As of September, employment in the Portland metro is down 4.8% from pre-pandemic levels, effectively identical to the 4.7 percent decline seen in the median large metro. Now, earlier in the pandemic, Portland did trail the typical large metro by a couple percentage points – likely impacted by the second round of more stringent public health policies and shutdowns – but that gap closed in recent months.

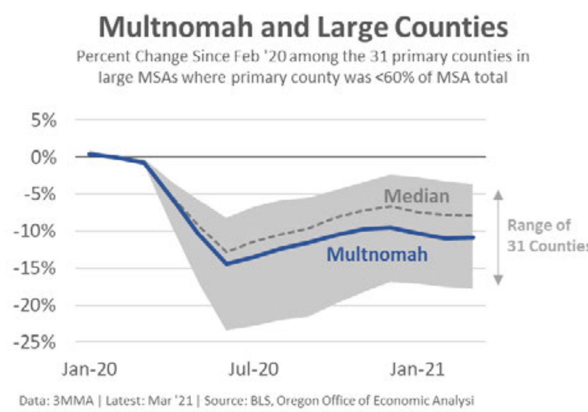
While Portland overall is in the middle of the pack this can be thought of as both good and bad news. On the good news front two things stand out. First, despite the pessimistic narrative or portrayal of Portland – a place where protests turn violent, a place that has been burning for decades according to the former President of the United States, a place overrun with homelessness, and the like – economically the region is average. Societal ills are not to be ignored and do need to be addressed. However there is a distinction between these societal challenges and underlying economic performance.



Second, Oregon's economy tends to be more volatile than the nation overall. We usually experience more severe recessions, and faster economic expansions. So far this cycle, Portland, and Oregon are experiencing an average-sized recession. The local economy is not starting from the bottom of the pack, like usual.

On the bad news front, while Portland may be pretty typical, the region does trail every one of its peer metro areas. As identified by the Portland Business Alliance, based on research from ECONorthwest, these peer metro areas are: Austin, Indianapolis, Nashville, Salt Lake and Seattle. Admittedly, these are very tough comparisons. Austin and Salt Lake are the two fastest growing large metros in the entire country. Portland is gaining noticeable ground on Indianapolis and a little on Nashville, making up some of the earlier differences. Portland and Seattle's labor markets are moving in tandem, likely due to similar pandemic trajectories and health policies, but Seattle employment is running about one percentage point stronger. While these peers make for challenging comparisons, Portland was certainly included in the same group last cycle.

While at the regional level, Portland is following trends seen throughout the country, what about the City of Portland and downtown in particular? Afterall, it is the urban core where the protests and violence occurred, where the unhoused are more visible, and where workers are making fewer commuting trips. The challenge here is data availability. A lot of economic data is published at the state, metro, and county level. In Oregon counties work well for analysis but this is not the case everywhere. For example, the entire metros of both Phoenix and San Diego are contained within a single county. There is no ability to look at the city versus suburbs in the standard economic data. Thankfully 31 of the largest metros in the country have some useful county level granularity. Even so, the best employment data at the county level lags considerably. As of this forecast publication, detailed county level data is only available through March 2021. Data through June will be released in the coming weeks.



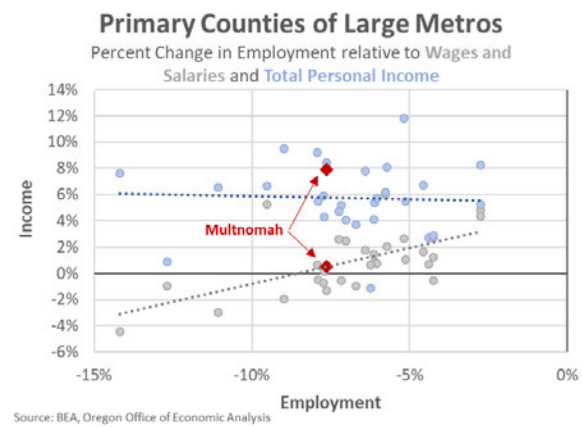
As of March 2021, Multnomah County employment since the start of the pandemic does trail the median large urban county by 3 percentage points. At the metro level, Portland trailed the median by 2 percentage points back in March. This is one indication that the city versus suburbs divergence is not necessarily more pronounced in Portland than elsewhere in the country. It may be, and the gap may not be closing as quickly locally, but the available data do not indicate this is happening. Data through September – timeframe for when the entire Portland region caught the typical large metro – will not be available until February or March of next year. This is one indicator our office will be following closely.

Employment is typically a good, real-time gauge of economic activity and growth. However, due to federal aid during the pandemic, this usual connection broke down. One of the explicit goals of federal policy was to ensure that Americans did not have to work during a pandemic just to put food on the able, if they did not want to. The goal was to slow the spread of the virus, with few financial repercussions for businesses and households. Between enhanced unemployment insurance benefits, recovery rebates, student loan deferrals, rent assistance, and the like, federal policy more than did its job.

In fact, as seen in the nearby scatterplot, overall income growth across metro areas last year was actually pretty consistent, regardless of local economic conditions. The blue dots are primarily in the +5-10% range for total income growth last year. However if one focuses just on the impact of job losses on wages and salaries, the relationship is quite clear. The gray dots show that larger job losses result in fewer wages earned. The difference between the gray and blue dots, again, is the substantial federal aid supporting household incomes everywhere, and more than enough to offset the variation in local job losses.

Specifically for Portland, the region lost 6.3 percent of its jobs on an annual average basis, which is noticeably larger than the median metro's losses of 4.9 percent. Even so, Portland's incomes grew 7.0 percent last year despite the severe recession. Portland's income growth was just a hair stronger than the median gain of 6.9 percent across all metro areas.

A similar pattern is seen if we focus just on Multnomah County relative to both all counties in the U.S. and the other primary counties in large metro areas. Multnomah's employment last year fell 7.6 percent which is noticeably larger than the typical U.S. county at 4.3 percent. However total incomes in Multnomah increased 7.9 percent which outpaced the typical U.S. county's 7.6 percent gain. Specifically comparing Multnomah to the primary counties of the region's peer metros, Multnomah's income growth all stands out a year ago. Income growth in Marion County, Indiana (Indianapolis MSA), Davidson, Tennessee (Nashville MSA), and King County, Washington (Seattle MSA) were all slower than Multnomah. Reasonable county granularity is not available for either the Austin or Salt Lake MSAs.

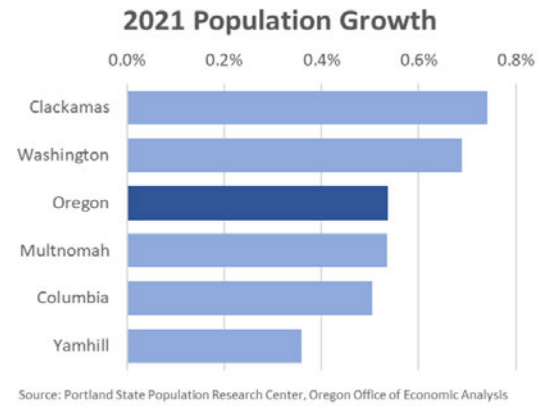


While local economic conditions may have mattered less in the past year and a half than at any point in recent memory the recovery is now at a crucial junction. The federal aid is gone. Local growth once again is in the driver's seat.

Near-term growth will largely be about consumer spending shifting back into services as we return more to our daily lives. Service industries are labor-intensive, which will drive strong near-term employment growth in the quarters ahead. Part of will be white collar workers return to the office a bit more, going on more business trips and the like, which supports urban cores and jobs centers across the country.

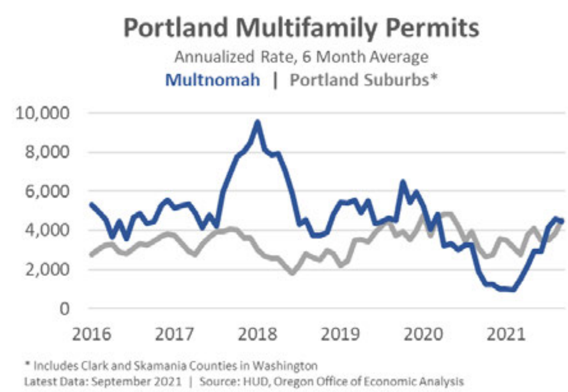
Long-term economic growth is about the number of workers a regional economy has and how productive each worker is. Portland, and Oregon more broadly, have benefitted substantially in recent decades from an influx of young, skilled households moving here, and strong business investment. The question today, given the pessimism built into the conventional wisdom, is whether Portland's longer-term growth prospects have been diminished. Is the region now a less desirable place to live, or run a business? Only time will tell. However, there are a few green shoots seen in the data.

First, this week Portland State University's Population Research Center released the preliminary 2021 county and city population estimates for Oregon. Typically during recessions, population growth slows as job opportunities are fewer and harder to come by. Population growth everywhere slowed in 2020, due to the pandemic and recession. Population growth was also slow in 2021. Some of the underlying details are not yet available, neither are revisions to population estimates last decade following the delayed release of the 2020 Decennial Census data.



However it is important to keep in mind that population growth it is still positive. More people moved into Oregon, the Portland region, and Multnomah County specifically than moved out. Expectations are that this net in-migration in the years ahead, bringing with it an influx of mostly younger, mostly skilled workers. This boosts longer-term economic growth prospects overall as local firms can hire and expand at a faster rate due to the larger workforce.

Second, Portland's reputation as a good place for business investment took a hit a year ago. For example, in last year's *Emerging Trends in Real Estate* annual report from the Urban Land Institute, the Portland market dropped from its normally high-ranking spot to 66th best nationwide. In this year's report, Portland rebounded to 49th best, which was the 10th largest increase in the rankings, but still lower than where the region ranked pre-pandemic. The biggest increases for Portland among the subcategories were in the local economy, and local public and private investments, while the region saw a relative decline in the investor demand subcategory.



While the ULI report is a survey based on market perceptions and investment opportunities, there is also a bright spot in the actual new construction permitting data. Initially, multifamily (apartment) permits dropped considerably at the beginning of the pandemic. Projects were put on hold, or worse, even canceled given the uncertain economic outlook and public health situation facing large cities nationwide. Encouragingly, permits for new apartment buildings in Multnomah County have been picking up throughout 2021. Today, the pace of new permits issued is nearly back to where it typically was pre-pandemic. It is not yet a full recovery, but it is certainly an encouraging trend.

The rebound in permitting activity, which will turn into economic activity and investment in the months ahead, is overall great news. One concern, however, is that the recent uptick may reflect delayed projects once again moving forward. While still good news, this could mean the permit activity overstates the actual increase in underlying demand and investment. Our office will continue to closely track new construction activity in the months ahead.

On the other hand, the need for more housing continues. Following a sizable building cycle in the urban core last decade, the apartment vacancy rate rose as more supply came on the market just as the pandemic hit. This was one reason why Portland's investment opportunities and perception declined, because segments of the market were beginning to be overbuilt.

Now, today the vacancy rate is declining and rents are rising. There are underlying market fundamentals supporting more construction. This points toward an ongoing economic recovery and increase in investments. Given housing affordability is a key concern our office has in terms of the ability to attract and retain workers, the regional economy needs more new construction.

Bottom Line: Ultimately people vote with their feet and their wallet. Expectations are that Portland, and Oregon more broadly will remain an attractive place to live. Most households move for quality of life, job opportunities, and/or housing reasons. As such, the regional economy is likely to experience above-average growth in the years ahead. The outlook is bright. Already the region has caught up economically to other large metro areas despite local social challenges and public perception. However, the key question is whether or not Portland will reclaim its perch among the highest fliers around the country, which remains to be seen.

Regional Comparison

Employment

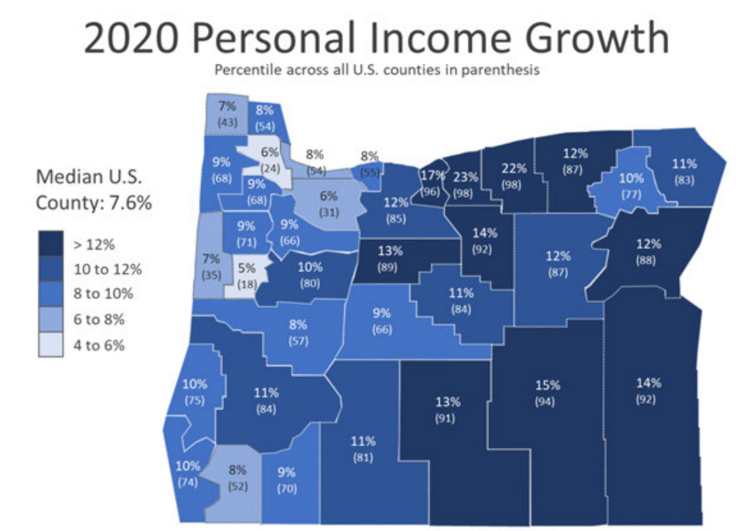
Oregon's regional economies continue to recover, albeit unevenly. Initial job losses in the pandemic, while severe everywhere, were largest in urban areas, and those more reliant upon travel and tourism. However as leisure travel has rebounded, regions like the North Coast, Gorge, and Central Oregon have similarly seen strong employment growth in the past year and a half. These regions have regained 80 percent of their initial job losses.

Conversely, as discussed in depth in the previous sector, Portland is growing and the outlook is brighter than the conventional wisdom suggests, but remains the worst performing regional economy in the state to date.

Many rural regions, particularly those east of the Cascades, are outperforming. Much of this has more to do with a stronger initial rebound from initial wave of the pandemic. Since then, however, job growth has slowed noticeably, even as their current relative positions over the entire cycle to date are stronger than the state average.

Personal Income

Thanks to the large federal fiscal policy response to the pandemic, incomes grew in 2020 despite a severe recession. Nationwide, 98 percent of all U.S. counties saw total personal income growth, including all 36 counties here in Oregon.



Incomes in rural America grew 7.6 percent overall last year, compared with 6.4 percent in urban America. A similar pattern is seen in Oregon. Income in much of eastern Oregon grew twice the national rate last year. Such gains (dark blue counties) are stronger than those seen in more than 90 percent of all U.S. counties.

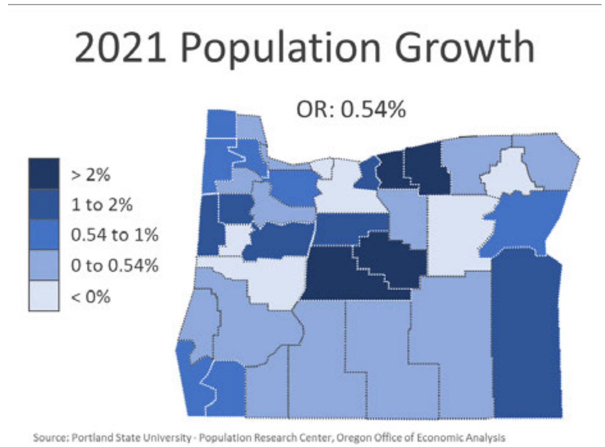
Western, and more urban counties in Oregon saw income growth that was more in line with the rest of the country. Only Benton and Washington counties saw income growth that was noticeably slower than elsewhere in the country, although both saw gains and not losses.

Population

Total population is a driver for overall economic activity as more households create local demand for housing, food, entertainment, and the like. Working-age population is the key for local economic growth as it provides the labor force from which local businesses – both local and traded sector – can hire and expand. Population growth tends to be pro-cylclical. Migration slows in recessions as job opportunities dry up and accelerates during expansions as households seek out the more-plentiful, and better-paying opportunities.

Population growth in 2020 was slower than in the years leading up to the pandemic and 2021 was largely more of the same. Oregon's population increased 0.5 percent this year. These continued slow population gains were built into our office's forecasts, and do run counter to the conventional wisdom that there was some great pandemic-related migration boom. The full details of the newly released estimates are not yet available, nor are official historical revisions to the 2010s estimates that take into account the 2020 Decennial Census data. Our office has adjusted the intercensal years in this forecast, even as we await the Census and Portland State revisions in the months ahead.

Even so, the estimates indicate that 30 out of Oregon's 36 counties saw population growth in the past year. The fastest growing counties were Morrow (3.4%), Crook (2.5%), Gilliam (2.2%), and Deschutes (2.1%).



At the regional level every region in the state added residents, except the Gorge where slight estimated population declines in both Hood River and Wasco offset the gains elsewhere. Overall the region is estimated to have lost 40 residents, which for all intents and purposes is a stable population, albeit one with a negative sign in front.

Due to the strong gains in Crook, Deschutes, and Jefferson (1.4%), the East Cascades region once again led overall population growth. Now, if there were any pandemic-related migration booms in the state, Central Oregon is the place the data indicate it did occur. The other counties in the East Cascades region – Klamath and Lake – did see slower, but positive gains.

All three counties in the North Coast Region – Clatsop, Lincoln, Tillamook – grew at above-average rates last year. Portland grew slightly faster than the rest of the state while the rural eastern and southwestern regions of Oregon saw slightly slower increases.

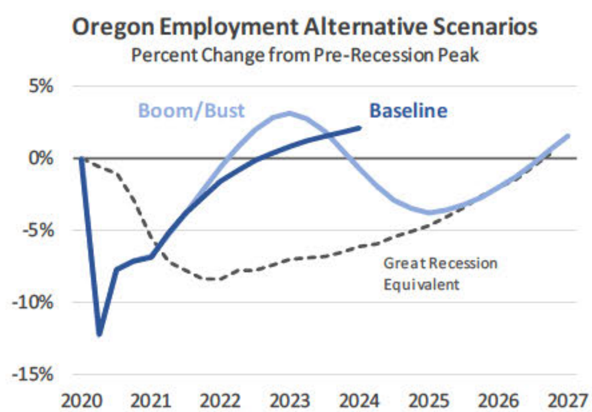
Given the employment strength seen in both the Rogue and Willamette Valley regions of the state, the slower population gains are somewhat of a surprise.

As more details on births, deaths, and migration become available, as do any breakdowns by age, and race and ethnicity, our office will continue to analyze the data for its implications of the current and future state of the regional economies.

Alternative Scenarios

The baseline forecast is our outlook of the most likely path for the Oregon economy. As with any forecast, however, many other scenarios are possible. Given the current economic dynamics and potential for inflation to run hotter, for longer, our office's standard optimistic and pessimistic scenarios are excluded this forecast in lieu of a boom/bust scenario.

Alternative Scenario **Dec 2021**



	2021	2022	2023	2024	2025	2026
Employment						
Baseline	2.3%	4.3%	1.9%	1.1%	0.8%	0.7%
Boom/Bust	2.4%	6.1%	0.8%	-4.3%	-1.1%	2.7%
Unemployment Rate						
Baseline	5.6%	4.4%	3.9%	3.9%	4.0%	4.1%
Boom/Bust	5.5%	3.1%	4.0%	8.2%	9.0%	7.2%
Personal Income						
Baseline	6.7%	0.6%	5.6%	5.5%	5.5%	5.5%
Boom/Bust	7.0%	2.2%	3.1%	1.2%	6.0%	7.3%
Consumer Spending						
Baseline	11.7%	6.3%	4.4%	5.0%	5.3%	5.4%
Boom/Bust	12.4%	8.5%	-0.7%	1.4%	7.5%	7.9%

Boom/Bust Scenario:

The inflationary boom continues. By the middle of 2022, employment, income, and spending are all 2-3 percentage points higher than the baseline. The unemployment rate drops to below 3 percent by late summer or early fall next year. Inflation cools from today's highs but remains closer to 4 percent. The Federal Reserve raises interest rates beginning in mid-2022, or six to nine months earlier than in the baseline outlook as a result. The policy goal is to cool the economy and bring inflation under control. However the end result of rising interest rates is to send the economy back into recession beginning in 2023. All told, Oregon loses more than 130,000 jobs and the unemployment rises to more than 9 percent due to the relatively long-lasting recession. Growth resumes in early 2025 and the recovery is strong compared to the aftermath of either the dotcom bust or Great Recession. Oregon's economy regains full employment in 2028.

REVENUE OUTLOOK

Revenue Summary

Oregon's primary sources of state tax revenues continue to outstrip expectations. Since the September forecast was released, daily collection records have been set for both personal income tax withholdings and corporate tax collections. In addition, Lottery sales continue to set records for this time of year.

Recent forecasts have called for tax collections to return to earth. Federal aid has expired, and economic activity is beginning to return to normal with workers reentering the labor force, returning to offices and spending more on services. Instead of normalizing, however, revenue growth has accelerated further.

The revenue boom is being supported by a wide range of income sources. Most importantly, healthy gains in labor income are generating personal income tax payments. Despite Oregon having lost more than 70,000 jobs relative to pre-pandemic levels, taxable wages and salaries are far above pre-pandemic trends. A persistently tight labor market is putting upward pressure on wages, leading to significant payroll growth despite the job losses.

The return of inflation after a 30-year hiatus is also generating additional revenue across a range of tax instruments. With demand so strong across the economy, businesses currently have a considerable amount of pricing power, and have been able to pass most of their cost increases along to consumers. As a result, profits and other taxable business incomes are booming. In addition to the direct boost to tax collections, healthy business earnings are supporting equity markets and other forms of investment income.

Inflation is also generating additional Corporate Activity Tax collections. Business sales are taxed by value, not by the quantity sold. As a result, tax liability has risen along with prices, and is expected to remain higher throughout the forecast horizon.

The recent revenue boom, together with an improving outlook for labor earnings, have led to a significant upward revision to the outlook for personal and corporate income tax collections. The current forecast now projects both a $558 million personal income tax kicker, and a $250 million corporate kicker as the forecasts have been raised more than 2 percent since the Close of Session. However, considerable uncertainty remains. Although the baseline outlook calls for continued growth, overheating remains a real possibility. Inflationary booms of the sort we are experiencing today traditionally do not end well, putting recent revenue gains at risk going forward.

Longer term, revenue growth in Oregon and other states will face considerable downward pressure over the 10-year extended forecast horizon. As the baby boom population cohort works less and spends less, traditional state tax instruments such as personal income taxes and general sales taxes will become less effective, and revenue growth will fail to match the pace seen in the past.

2019-21 General Fund Revenues

Gross General Fund revenues for the 2021-23 biennium are expected to reach $24,134 million. This represents an increase of $710 million from the September 2021 forecast, and an increase of $807 million relative to the Close of Session forecast. Personal and corporate income tax collections continue to set records. Among non-General Fund sources, revenues tied to consumer spending including lottery sales and the new Corporate Activity Tax are outstripping expectations as well.

Table R.1

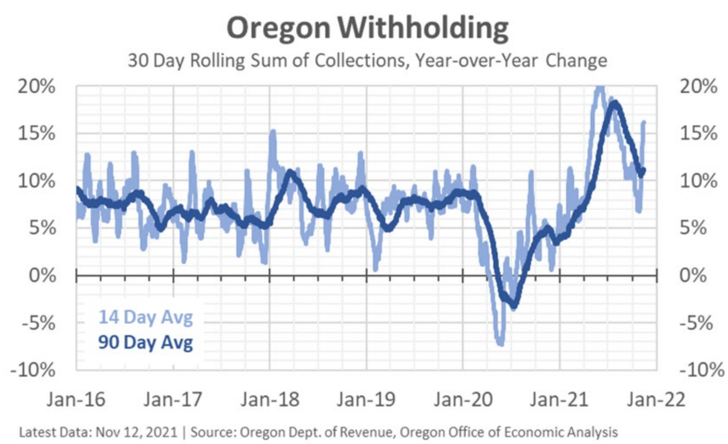
2021-23 General Fund Forecast Summary

(Millions)	2021 COS Forecast	September 2021 Forecast	December 2021 Forecast	Change from Prior Forecast	Change from COS Forecast
Structural Revenues					
Personal Income Tax	$20,628.1	$20,657.0	$21,159.1	$502.1	$531.1
Corporate Income Tax	$1,344.0	$1,410.0	$1,594.2	$184.3	$250.3
All Other Revenues	$1,353.5	$1,357.4	$1,380.7	$23.3	$27.3
Gross GF Revenues	$23,325.5	$23,424.4	$24,134.1	$709.7	$808.6
Offsets and Transfers	-$171.5	-$174.2	-$180.9	-$6.7	-$9.4
Administrative Actions[1]	-$21.5	-$21.5	-$21.5	$0.0	$0.0
Legislative Actions	-$224.6	-$224.6	-$224.6	$0.0	$0.0
Net Available Resources	$26,008.4	$26,783.3	$27,486.3	$703.0	$1,477.9
Confidence Intervals					
67% Confidence	+/- 7.3%		$1,763.6	$22.37B to $25.90B	
95% Confidence	+/- 14.6%		$3,527.1	$20.61B to $27.66B	

1 Reflects cost of cashflow management actions, exclusive of internal borrowing.

Personal Income Tax

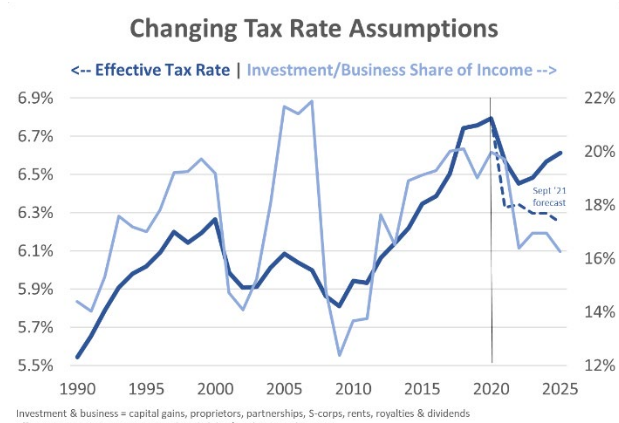
Strong personal income tax collections have come from a range of sources, including a boom in withholdings. Personal income tax withholdings are driven primarily by wages and salaries in the labor market. Along with strong growth in employment and wages, withholdings are expanding at a double-digit rate. In addition to larger paychecks, growth in retirement income and the expanded unemployment insurance benefits have also supported withholdings.



In addition to withholdings, estimated tax payments and payments with returns are posting large gains as well. The extension filing season has just come to a close, and brought with it an unusual amount of tax collections. Although extension filers must pay their bill at the April deadline (July this year), this season extension filers discovered significantly more taxable income after their returns were complete.

Extension filers include many of the most complicated tax returns, and those with the highest reported income. High-income filers did particularly well in 2020, with business and investment income strong despite the pandemic-related downturn. When high-income filers do well, the support to tax collections becomes supercharged. In this environment, aggregate tax liability grows even faster than underlying income gains. As a larger share of income is taxed at Oregon's top rate, the average tax rate increases. The opposite dynamic holds during periods when investments and business income lose value. During downturns, Oregon's revenues fall faster than underlying income levels.

Every 100 basis point change in Oregon's average tax rate translates to roughly $130 million in additional revenues. As such, if the average tax rate matched what we saw in 2015, annual revenues would be around $1 billion lower.

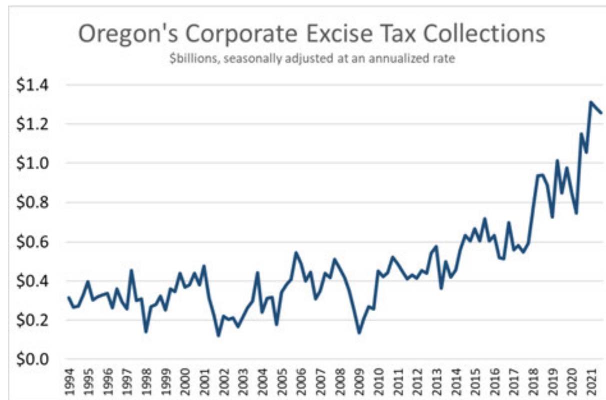


Investment & business = capital gains, proprietors, partnerships, S-corps, rents, royalties & dividends
Effective tax rate = Oregon personal tax liability/total reported income

This volatility is apparent in recent collections of personal income taxes and other General Fund sources. According to the December forecast, the outlook for the current biennium is now 2.5% higher than the Close of Session forecast, slightly above the kicker threshold. With two tax filing seasons left in the biennium, much uncertainty remains. However, if the current outlook holds, a kicker of $558 million would be paid out when taxes are filed in 2024.

Corporate Excise Tax

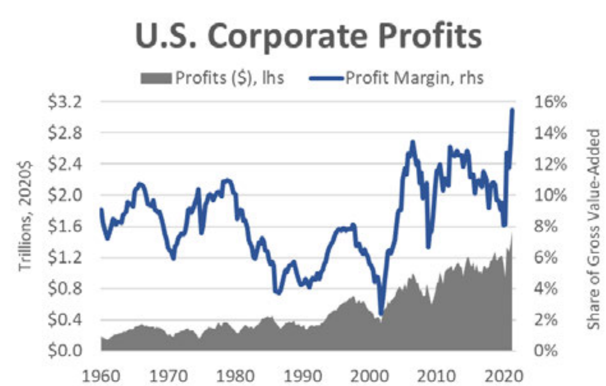
Corporate excise tax collections have yet to weaken at all. After a temporary drop at the beginning of the recession, corporate tax collections immediately bounced back and continue to set new records. This stands in stark contrast to the last two recessions when corporate tax collections were cut in half. In fiscal year 2021, corporate collections rose by 44%. When return data becomes available, it will be interesting to see if some of this growth has been fueled by new corporations. The number of C-corporations filing Oregon tax returns has been stuck around 30,000 for several years.



The strong performance of corporate taxes is particularly surprising given that they were expected to come back down to earth even before the recession began. The subtraction for taxes paid under Oregon's new Corporate Activity Tax is reducing traditional liability, as is the subtraction for expenditures funded by forgiven Payroll Protection Program loans. Even so, collections have doubled over the last two budget periods.

The current inflationary environment is one factor supporting corporate tax collections. With underlying demand so strong, businesses have largely been able to pass cost increases along to their customers. As a result, profits and earnings have skyrocketed.

While some of this increase likely reflects a permanent increase in the tax base, a significant amount of the growth is expected to be temporary. As with business and investment income on personal tax returns, corporate taxpayers are pulling income forward in advance of possible federal tax legislation.



Profit margin defined as after-tax profits as share of gross value-added for nonfinancial corporate businesses
Source: BEA, Oregon Office of Economic Analysis

Although there is a very long way to go, a $250 million kicker is currently estimated for the next biennium. According to statute, this would lead to additional funding for K-12 education during the 2023-25 budget period.

Other Sources of Revenue

Non-personal and non-corporate revenues in the General Fund usually account for approximately 6 or 7 percent of the total. The largest such source are estate taxes, followed by liquor revenues, and judicial revenues.

Relative to the previous forecast, the current outlook for these revenues in 2021-23 is raised by $23.3 million (+1.8%). The increases are primarily due to estate taxes (+$13 million) and interest earnings (+$10 million) coming in above expectations. Additional changes are made to the insurance taxes (+$0.1 million), and securities fees (-$0.3 million) forecasts, with a slight upward revision to tobacco revenues (+$0.6 million). Total tobacco revenues are increased by a larger $12.9 million however most of these revenues are not in the General Fund. In particular inhalant delivery revenues, a new tax in 2021, continue to come in significantly above initial expectations. The current 2021-23 forecast is raised $5.9 million due to recent collections, while no longer-term forecast adjustments have been made yet given the newness of the tax. Our office will continue to monitor these revenues and quarterly tax returns filed by Oregon businesses and adjust the forecast as we learn more. See Table B.6 in Appendix B for the full details on tobacco revenue distributions.

Extended General Fund Outlook

Table R.2 exhibits the long-run forecast for General Fund revenues through the 2029-31 biennium. Users should note that the potential for error in the forecast increases substantially the further ahead we look.

Table R.2

General Fund Revenue Forecast Summary (Millions of Dollars, Current Law)

Revenue Source	Forecast 2019-21 Biennium	% Chg	Forecast 2021-23 Biennium	% Chg	Forecast 2023-25 Biennium	% Chg	Forecast 2025-27 Biennium	% Chg	Forecast 2027-29 Biennium	% Chg	Forecast 2029-31 Biennium	% Chg
Personal Income Taxes	20,047.0	6.5%	20,657.0	3.0%	24,408.9	18.2%	26,596.6	9.0%	29,610.9	11.3%	33,216.3	12.2%
Corporate Income Taxes	2,041.4	16.5%	1,410.0	-30.9%	1,622.4	15.1%	2,004.4	23.5%	2,228.0	11.2%	2,497.9	12.1%
All Others	1,681.1	25.5%	1,432.3	-14.8%	1,433.8	0.1%	1,505.1	5.0%	1,613.5	7.2%	1,686.8	4.5%
Gross General Fund	23,769.5	8.5%	23,499.3	-1.1%	27,465.1	16.9%	30,106.2	9.6%	33,452.4	11.1%	37,401.1	11.8%
Offsets and Transfers	*(114.8)*		*(174.2)*		*(106.7)*		*(83.4)*		*(92.7)*		*(103.9)*	
Net Revenue	23,654.7	8.6%	23,325.0	-1.4%	27,358.5	17.3%	30,022.8	9.7%	33,359.7	11.1%	37,297.2	11.8%

Revenue growth in Oregon and other states will face considerable downward pressure over the 10-year extended forecast horizon. As the baby boom population cohort works less and spends less, traditional state tax instruments such as personal income taxes and general sales taxes will become less effective, and revenue growth will fail to match the pace seen in the past.

Tax Law Assumptions

The revenue forecast is based on existing law, including measures and actions signed into law during the 2021 Oregon Legislative Session. OEA makes routine adjustments to the forecast to account for legislative and other actions not factored into the personal and corporate income tax models. These adjustments can include expected kicker refunds, when applicable, as well as any tax law changes not yet present in the historical data. A summary of actions taken during the 2021 Legislative Session can be found in Appendix B Table B.3. For a detailed treatment of the components of the 2021 Legislatively Enacted Budget, see:

Legislative Fiscal Office's 2021-23 Budget Summary

Although based on current law, many of the tax policies that impact the revenue forecast are not set in stone. In particular, sunset dates for many large tax credits have been scheduled. As credits are allowed to disappear, considerable support is lent to the revenue outlook in the outer years of the forecast. To the extent that tax credits are extended and not allowed to expire when their sunset dates arrive, the outlook for revenue growth will be reduced. The current forecast relies on estimates taken from the Oregon Department of Revenue's 2021-23 Tax Expenditure Report together with more timely updates produced by the Legislative Revenue Office.

General Fund Alternative Scenarios

The latest revenue forecast for the current biennium represents the most probable outcome given available information. Our office feels that it is important that anyone using this forecast for decision-making purposes recognize the potential for actual revenues to depart significantly from this projection.

Table R.2b - General Fund Forecast (December 2021) - BoomBust Scenario

Personal Income Tax	2021-23	2023-25	2025-27	2027-29	2029-31
Baseline	$21,159.1	$24,889.8	$27,564.3	$30,992.9	$35,165.7
BoomBust	$21,484.9	$24,369.0	$26,794.1	$31,046.6	$35,693.5
Difference	*$325.8*	*-$520.8*	*-$770.2*	*$53.7*	*$527.8*
Corporate Income Tax	**2021-23**	**2023-25**	**2025-27**	**2027-29**	**2029-31**
Baseline	$1,594.2	$1,601.8	$1,934.9	$2,168.1	$2,478.0
BoomBust	$1,568.8	$1,521.4	$1,826.1	$2,108.4	$2,441.6
Difference	*-$25.4*	*-$80.4*	*-$108.8*	*-$59.8*	*-$36.4*
Other General Fund	**2021-23**	**2023-25**	**2025-27**	**2027-29**	**2029-31**
Baseline	$1,455.6	$1,447.9	$1,529.7	$1,617.0	$1,686.5
BoomBust	$1,434.1	$1,375.8	$1,443.3	$1,572.2	$1,661.7
Difference	*-$21.6*	*-$72.1*	*-$86.4*	*-$44.7*	*-$24.9*
Total General Fund	**2021-23**	**2023-25**	**2025-27**	**2027-29**	**2029-31**
Baseline	$24,209.0	$27,939.5	$31,028.9	$34,778.0	$39,330.2
BoomBust	$24,487.8	$27,266.3	$30,063.5	$34,727.2	$39,796.8
Difference	*$278.8*	*-$673.3*	*-$965.4*	*-$50.8*	*$466.6*

Table R.2b shows the revenue implications of the Boom/Bust economic scenario described on page 15. In this scenario, revenues continue to boom this biennium, resulting in a larger projected kicker. The ensuring recession after the Federal Reserve hikes interest rates to head off inflation takes a toll on state resources. Revenues in both 2023-25 and 2025-27 are considerably below the baseline outlook. '

Corporate Activity Tax

HB 3427 (2019) created a new state revenue source by implementing a corporate activity tax (CAT) that went into effect January 2020. Collections related to the 2020 tax year are now expected to total approximately $1,054.0 million, which is somewhat lower that projected at the September forecast due to greater-than-expected refunds in October. At the same time, significantly higher estimated payments for the third quarter of tax year 2021 than previously predicted have increased the projection for collections related to this tax year. As a result, the forecast for revenues in the 2021-23 biennium have risen to $2,392.7 million. Given little change in the economic outlook, the forecast for CAT revenues in future biennia has also increase substantially.

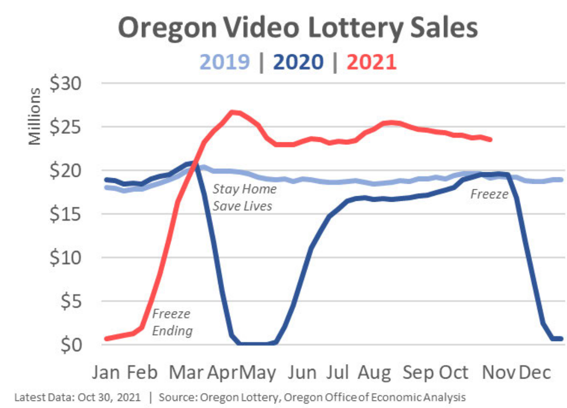
These revenues are dedicated to spending on education. The legislation also included personal income tax rate reductions, reducing General Fund revenues. The net impact of HB 3427 was designed to generate approximately $1 billion per year in new state resources, or $2 billion per biennium.

In terms the macroeconomic effects of a major new tax, the Office of Economic Analysis starts with the Legislative Revenue Office's (LRO) impact statement and any Oregon Tax Incidence Model (OTIM) results LRO found. At the top line, OTIM results find minimal macroeconomic impacts across Oregon due to the new tax. Personal income, employment, population, investment and the like are less than one-tenth of a percent different under the new tax relative to the baseline. The model results also show that price levels (inflation) will increase above the baseline as some of the CAT is pushed forward onto consumers. Of course these top line, statewide numbers mask the varying experiences that individual firms and different industries will experience. There are likely to be some businesses or sectors that experience large impacts from the CAT, or where pyramiding increases prices to a larger degree, while other businesses or sectors see relatively few impacts.

Table B.12 in Appendix B has details on 10 year forecast and the allocation of resources, while the personal income tax reductions are built into the General Fund forecasts shown in Tables B.1 and B.2.

Lottery Earnings

Video lottery sales continue to be strong. Sales have slowed some since the summer, as expected, but remain considerably higher than at any other point in history for this time of year. This strength is now expected to continue through the fall and into the winter, as sales slowly taper to be in line with their pre-pandemic share of income and consumer spending.

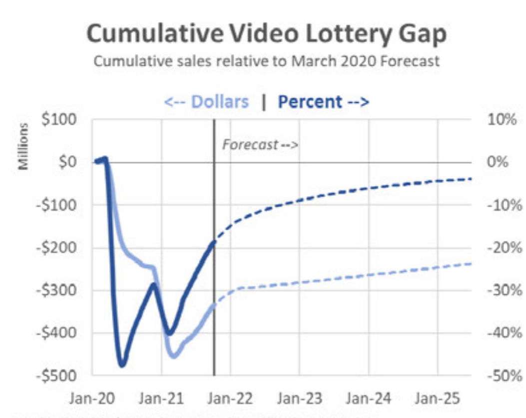


The upshot is lottery revenues for the current 2021-23 biennium are raised $22.4 million (+1.3%) compared to the previous forecast. 2021-23 revenues are now $70.9 million (+4.3%) above Close of Session estimates. Longer-term forecasts are adjusted somewhat higher due to a stronger economic outlook. Revenues for each biennium from 2023-25 through 2029-31 are increased by about 0.5 percent, or $8-9 million.

In terms of the near-term video lottery sales outlook, the key question is whether sales more closely follow current income, or track cumulative changes since the start of the pandemic. The answer matters considerably for just how long record-setting sales are likely to last.

On the one hand, current income growth is slowing as the federal aid is gone. Labor income is booming, but that is essentially offsetting the fading federal impacts. The nature of our previous forecast was sales would slow this fall as a result, that some or much of the record sales was due to households having extra money and limited entertainment options. It remains our office's view that current spending is predominantly determined by current income.

However, on the other hand, cumulative video lottery sales since the start of the pandemic are $334 million (-19%) below pre-pandemic expectations. Record sales in recent weeks are not yet enough to offset the revenue declines during the two rounds of shutdowns. Conversely, incomes are noticeably higher than pre-pandemic expectations. Households have considerable excess savings they can use to spend, if they want to.



Today, both factors – current income and cumulative effects of the pandemic – are likely impacting sales. Pent-up demand is real given players were unable to game during the shutdown periods, and some were more hesitant to venture out during a global pandemic.

However, the forecast expects some normalization in the months ahead for at least three key reasons. First, given the limited, available information it is more likely that the current level of sales is existing players gaming more, than it is an underlying increase in the number of Oregonians playing. Second, following this is the likely fading impact of both federal aid on incomes, and pent-up demand from shutdowns that are now nearly one and two years ago. Spending will become increasingly reliant on current incomes moving forward. Third, there will be increased competition for entertainment dollars as Oregonians go on vacations, to sporting events, movie theaters and the like in greater numbers moving forward.

All told the outlook for video lottery is raised in the near-term. Record-setting sales, while tapering in the months ahead, are expected to continue into the beginning of next year. Risks to the outlook are slightly weighted toward the upside, and especially so in sales or dollar terms. First, on the downside, the adjustment of sales to current income growth may prove quicker than anticipated. Such a development would reduce current 2021-23 revenues a little – likely half of the increase this forecast is raised – but leave the longer-run forecast unchanged.

However, on the upside, given we are now nearly two years into the pandemic, it is likely some permanent behavioral changes have been made. One of those could be permanently higher video lottery sales. To the extent that sales are a permanently higher share of income, or that the excess savings maintains these level of sales for years to come, the current outlook is noticeably conservative.

Big picture changes, like permanently higher sales will take time to fully realize. This is especially true today given the unprecedented public health and economic times we find ourselves in. Furthermore, the ultimate impact of unprecedented federal policy is also not fully understood today. Our office will continue to analyze gaming trends here in Oregon and across the country, and to what extent there are permanent shifts once the economy, and society more broadly return to something more approaching the pre-pandemic normal.

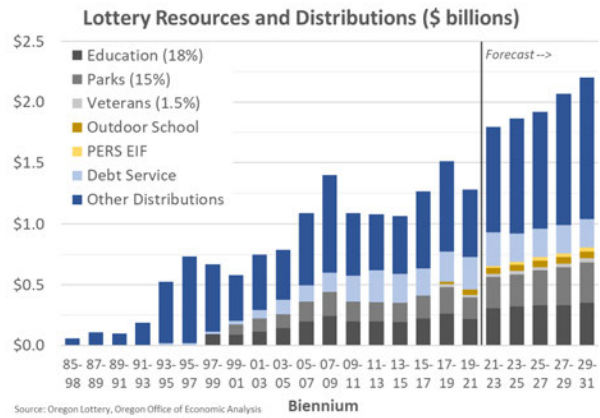
Finally, one additional risk to the outlook is the potential for increased gaming competition within Oregon. Specifically a new gaming facility in Grants Pass in southern Oregon would result in lower video lottery sales in the region. For example, a study from ECONorthwest[2] found that the impact of facility could be a $13 million reduction in video lottery sales. One broader issue raised is the potential for other such gaming facilities at the other three horse betting tracks in the state. No decisions have been in granting or denying the proposal, as such no impact is built into the outlook.

Lottery Outlook and Distributions

Big picture issues to watch include broader national trends in gaming markets, demographic preferences for recreational activities, and to what extent consumers decrease the share of their incomes spent on gaming. Last expansion consumers remained cautious with their disposable income until late in the cycle. Increases in spending on gaming had largely matched income growth.

[2] https://cdn.kobi5.com/wp-content/uploads/2021/10/Historical-Horse-Race-Impacts-FINAL-Sept-17-2021-.pdf?x47684

Over the long run our office expects increased competition for household entertainment dollars, increased competition within the gaming industry, and potentially shifts in generational preferences and tastes when it comes to gaming. As such, our outlook for video lottery sales is continued growth, however at a rate that is slightly slower than overall personal income growth. Lottery sales will continue to increase as Oregon's population and economy grows, however video lottery sales will likely be a slightly smaller slice of the overall pie.



The full extended outlook for lottery earnings can be found in Table B.9 in Appendix B.

Budgetary Reserves

The state currently administers two general reserve accounts, the Oregon Rainy Day Fund[3] (ORDF) and the Education Stability Fund[4] (ESF). This section updates balances and recalculates the outlook for these funds based on the September revenue forecast.

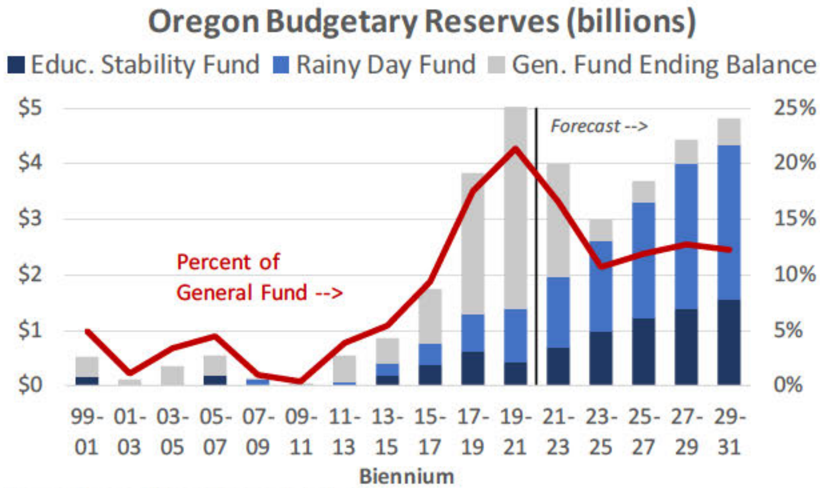
As of this forecast the two reserve funds currently total a combined $1.42 billion. At the end of the current 2021-23 biennium, they will total $1.96 billion. Including the currently projected $2.04 billion ending balance in the General Fund, the total effective reserves at the end of the current 2021-23 biennium are projected to be $4.0 billion, or 16.5% of current revenues.

The forecast for the ORDF includes two deposits for this biennium relating to the General Fund ending balance from the previous biennium (2019-21). A deposit of $224.6 million is expected to be made in early 2022 after the accountants close the books. Additionally a $64.9 million deposit relating to the increased corporate taxes from Measure 67 is expected at the end of the biennium in June 2023. This exact transfer amount is subject to some revision as corporate filings are processed, however the transfer itself will occur. At the end of 2021-23 the ORDF will total $1.27 billion.

Looking ahead to the 2023-25 biennium, the ORDF is expected to receive two transfers as well. This includes a projected $254.5 million related to the General Fund ending balance from 2021-23, and $66.6 million related to the increase in corporate taxes. The ORDF is not projected to hit its cap of 7.5% of revenues until FY2029.

[3] The ORDF is funded from ending balances each biennium, up to one percent of appropriations. The Legislature can deposit additional funds, as it did in first populating the ORDF with surplus corporate income tax revenues from the 2005-07 biennium. The ORDF also retains interest earnings. Withdrawals from the ORDF require one of three triggers, including a decline in employment, a projected budgetary shortfall, or declaration of a state of emergency, plus a three-fifths vote. Withdrawals are capped at two-thirds of the balance as of the beginning of the biennium in question. Fund balances are capped at 7.5 percent of General Fund revenues in the prior biennium.

[4] The ESF gained its current reserve structure and mechanics via constitutional amendment in 2002. The ESF receives 18 percent of lottery earnings, deposited on a quarterly basis – 10% of which are deposited in the Oregon Growth sub-account. The ESF does not retain interest earnings. The ESF has similar triggers as the ORDF, but does not have the two-thirds cap on withdrawals. The ESF balance is capped at five percent of General Fund revenues collected in the prior biennium.



Source: Oregon Office of Economic Analysis

Effective Reserves ($ millions)

	Current Nov-21	*End 2021-23*
ESF	$451	$693
RDF	$964	$1,265
Reserves	$1,415	$1,958
Ending Balance	$2,040	$2,040
Total	**$3,456**	**$3,999**
% of GF	14.5%	16.5%

The ESF will receive an expected $279 million in deposits in the current 2021-23 biennium based on the current lottery forecast. At the end of current 2021-23 biennium the ESF will stand at $693.4 million. The ESF is not projected to hit its cap of 5% of revenues until FY2027, when the deposits will then accrue to the Capital Matching Account.

Together, the ORDF and ESF are projected to have a combined balance of $1.96 billion at the close of the 2021-23 biennium, or 8.2 percent of current revenues. At the close of 2023-25 the combined balance will be $2.61 billion, or 9.4 percent of revenues. Such levels of reserve balances are larger than Oregon has been able to accumulate in past cycles, and should help stabilize the budget when the next recession hits.

B.10 in Appendix B provides more details for Oregon's budgetary reserves.

Recreational Marijuana Tax Collections

Marijuana sales continue to track the forecast closely. No fundamental changes are made to the outlook, other than updating for the most recent few months of sales, which are $3.1 million (+0.3%) above expectations.

In the near-term, sales are expected to slow as the pandemic improves and Oregonians continue to return to their pre-COVID lives. This includes white collar workers returning to the office a bit more, and other entertainment options opening up and being frequented more often. Some of the pandemic-related increase in marijuana sales is likely to come off, even as most sticks.

Latest Data: 2021q3 | Source: OLCC, Oregon Dept of Revenue, Oregon Office of Economic Analysis

Over the medium- and long-term, sales are expected to increase as Oregon's population, income, and spending grow. However at this point our office does not have a further increase in marijuana usage rates built into the outlook. As such, the risks lie primarily to the upside should usage and broader social acceptance continue to increase. The next National Survey on Drug Use and Health should be released in early 2022 providing an update on usage trends by age and across states in the past year. In consultation with our advisors, should we expect usage rates to increase further in the years ahead, the longer-run forecast would be adjusted accordingly.

See Table B.11 in Appendix B for a full breakdown of revenues, including the newly added medical marijuana revenue, and associated distributions to recipient programs.

POPULATION AND DEMOGRAPHIC OUTLOOK

Population and Demographic Summary

Oregon's resident population count on April 1, 2020 was 4,237,256. This is from the newly released decennial census data administered by the U.S. Census Bureau. During the past decade, Oregon gained 406,182 residents or 10.6 percent. The gain was substantial enough that yielded one additional congressional seat for the state. Oregon will have a total of six members in the House of Representatives. We have been predicting this rare gain for a long time. This is rare because only five states gained one additional seat each and Texas gained two seats.

In historical context, Oregon's population growth between 2010 and 2020 censuses was the second lowest since the first census count in Oregon in 1850. The lowest growth rate was recorded between the 1980 and 1990 censuses, a decade characterized by a major recession. Oregon's population increased by 441 percent in a century. The gain of 406,182 persons in the last decade alone was nearly the same as the total population count of Oregon in the year 1900 when state's population was 403,536. Oregon's population growth of 10.6 percent in the last decade was 11th highest in the nation, excluding Washington D.C. Still, our growth rate for the decade lagged behind all our neighboring states, except California. The prior decade between 2000 and 2010, Oregon's population growth rate ranked 18th highest in the nation when Oregon was hit hard by the double recessions during the decade. As a result of such economic downturn during the Great Recession and sluggish recovery that followed, Oregon's population increased at a slow pace between 2000 and 2010 decade. However, Oregon's population was showing moderately strong growth as a consequence of state's strong economic recovery. The current COVID-19 pandemic has caused dire economic and employment situations and has caused slow population growth. The population growth is expected to rebound after 2021. Based on the current forecast, Oregon's population is expected to reach 4.589 million in the year 2029 with an annual rate of growth of 0.81 percent between 2021 and 2029. The projected population of 2029 is 59,600 less than our March 2020 forecast released just before the COVID hit. The lower projection is due to the lingering COVID-19 effect resulting in higher deaths, lower births, and fewer net-migration, and 2020 Census count coming lower than expected based on the estimates by Population Research Center, Portland State University.

Oregon's economic condition heavily influences the state's population growth. Its economy determines the ability to retain existing work force as well as attract job seekers from national and international labor market. As Oregon's total fertility rate remains well below the replacement level and number of deaths continue to rise due to aging population, long-term growth comes mainly from net in-migration. The COVID-19 pandemic has left noticeable impact on demographic processes. Due to the declining births and rising deaths, we were expecting natural increase (births minus deaths) to turn negative after the year 2025. However, Oregon's natural increase has already turned negative because of the COVID effect. Even during this pandemic, Oregon has gained people through net-migration as the worker are able to work from home in many sectors. Working-age adults come to Oregon as long as we have favorable economic conditions and offers better quality of life. During the 1980s, which included a major recession and a net loss of population during the early years, net migration contributed to 22 percent of the population change. On the other extreme of the economic cycle, net migration accounted for 76 percent of the population change during the booming economy of early 1990s. This share of migration to population change declined to 32 percent in 2010 as a result of economic recession, lowest since early 1980s when we actually had negative net migration for several years. As a sign of slow to modest economic gain and declining natural increase (births minus deaths), the ratio of net migration-to-population change has registered at 89 percent in 2020. As a result of sudden rise in the number of deaths and fall in the number of births due to the COVID-19 pandemic, the natural increase will turn negative beyond the year 2020 through 2029 and beyond. So, in the future, all of Oregon's population growth and more will come from the net migration due to the combination of continued positive net migration, well below replacement level fertility, and the rise in the number of deaths associated with the increase in the elderly population. Thus, migration will be solely responsible for Oregon's population growth.

Age structure and its change affect employment, state revenue, and expenditure as the demand for services varies by age groups. Demographics are the major budget drivers, which are modified by policy choices on service coverage and delivery. Births, deaths, and migration history of over 100 years do impact the current age-sex structure. Growth in many age groups will show the effects of the baby-boom and their echo generations during the forecast period of 2021-2029. It will also reflect demographics impacted by the depression era birth cohort combined with changing migration of working age population and elderly retirees through history. After a period of relatively slow growth during the 1990s and early 2000s, the elderly population (65+) has picked up a faster pace of growth since 2005. This population group will maintain the high growth as the second half of the baby-boom generation continue to enter this age group combined with the attrition of small depression era birth cohort due to death. This age cohort, however, has hit the plateau of high growth rates exceeding 4 percent annually between 2011 and 2019. The group will experience continued high but diminishing rate of growth. The average annual growth of the elderly population will be 2.5 percent during the 2021-2029 forecast period. Different age groups among the elderly population show quite varied and fascinating growth trends. The youngest elderly (aged 65-74), which has been growing at an extremely fast pace in the recent past averaging 5.1 percent annually between 2010 and 2020 due to the direct impact of the baby-boom generation entering and smaller pre-baby boom cohort exiting this 65-74 age group. This fast paced growth rate will taper off to negative growth by the end of the forecast period as a sign of the end of the baby-boom generation transitioning to elderly age group. This high growth transitioning into a net loss of this youngest elderly population result in 0.5 percent annual average growth rate in the next eight years. The next older generation of population aged 75-84 has seen reversal of several years of slow growth and a period of shrinking years. The elderly aged 75-84 started to show a positive growth as the effect of depression era birth-cohort has dissipated. An unprecedented fast pace of growth of population in this age group has started as the baby-boom generation is starting to mature from the youngest elderly into this 75-84 age group. Annual growth rate during the forecast period of 2021-2029 is expected to be unusually high 5.5 percent. After a period of slow growth, the oldest elderly (aged 85+) will continue to grow at a strong rate but steadily gaining growth momentum due to the combination of cohort change, continued positive net migration, and improving longevity. The average annual rate of growth for this oldest elderly over the forecast horizon will be 3.6 percent. An unprecedented growth in oldest elderly will commence near the end of the forecast horizon as the fast growing 75-84 age group population transition into this oldest elderly age cohort. As a sign of massive demographic structural change of Oregon's population, starting in 2023 the number of elderly population will exceed the number of children under the age of 18. To illustrate the contrast, in 1980 elderly population numbered less than half of the number of children in Oregon.

The oldest working age population aged 45-64 also has seen the dramatic demographic impact as the baby-boom generation matures out of oldest working-age cohort which is replaced by smaller baby-bust cohort or Gen X. As the effect of this demographic transition combined with slowing net migration, the once fast-paced growth of population aged 45-64 has gradually tapered off to below zero percent rate of growth by 2012 and has remained and will remain at slow or below zero growth phase for several years. The size of this older working-age population will see only a small increase by the end of the forecast period. The younger working-age population of 25-44 age group has recovered from several years of declining and slow growing trend. The decline was mainly due to the exiting baby-boom cohort. This age group has seen positive but slow growth starting in the year 2004 and has gained steam since 2013. This group will increase by 1.0 percent annual average rate during the forecast horizon mainly because of the exiting smaller birth (baby-bust) cohort being replaced by larger baby-boom echo cohort. The young adult population (aged 18-24) will see only a small change over the forecast period. Although the slow or stagnant growth of college-age population (age 18-24), in general, tend to ease the pressure on public spending on higher education, but college enrollment typically goes up during the time of very competitive job market, high unemployment, and scarcity of well-paying jobs when even the older people flock back to colleges to better position themselves in a tough job market. The growth in K-12 population (aged 5-17) has been very slow or negative in the past and is expected to decline through the forecast years. This will translate into slow growth or even decline in the school enrollments. On average for the forecast period, this school-age population will decline by -0.8 percent annually. The growth rate for children under the age of five has remained near or below zero percent in the recent past and will continue to decline in the near future due to the sharp decline in the number of births. Although the number of children under the age of five declined in the recent years, the demand for child care services and pre-Kindergarten program will be additionally determined by the labor force participation and poverty rates of the parents.

Overall, elderly population over age 65 will increase rapidly whereas the number of children will actually decline over the forecast horizon. The number of working-age adults in general will show slow growth during the forecast horizon. Hence, based solely on demographics of Oregon, demand for public services geared towards children and young adults will likely to decline or increase only at a slower pace, whereas demand for elderly care and services will increase rapidly.

Procedure and Assumptions

Population forecasts by age and sex are developed using the cohort-component projection procedure. The population by single year of age and sex is projected based on the specific assumptions of vital events and migrations. Oregon’s estimated population of July 1, 2020 based on the most recent decennial census is the base for the forecast. To explain the cohort-component projection procedure very briefly, the forecasting model "survives" the initial population distribution by age and sex to the next age-sex category in the following year, and then applies age-sex-specific birth and migration rates to the mid-period population. Further iterations subject the in-and-out migrants to the same mortality and fertility rates.

The U.S. Census Bureau just released apportionment and resident population count of April 1, 2020 for the states. This is the crucial information as the base for all future postcensal population estimates and projections. Also, this 2020 census population is used to determine the error of closure, which is the difference between the actual census enumeration and the estimate based on the previous census of 2010. Again, the error of closure is used to correct and adjust all previous annual postcensal estimates for the time between 2010 and 2020. Since the Bureau has released only the total population, OEA has estimated only the total intercensal population for Oregon based on 2010 and 2020 census counts and postcensal estimates of Population Research Center, Portland State University. Therefore Oregon's intercensal population estimates for the years 2011 through 2020 in this forecast shown in Appendix C are different from prior postcensal numbers. Once the Bureau releases age-sex detail of the census population, OEA will produce readjusted intercensal estimates by age and sex for each of the years from 2011 through 2020. The numbers of births and deaths through 2020 are from Oregon's Center for Health Statistics. All other numbers and age-sex detail are generated by OEA.

Annual numbers of births are determined from the age-specific fertility rates projected based on Oregon's past trends and past and projected national trends. Oregon's total fertility rate is assumed to be 1.4 per woman in 2020 and this rate is projected to remain at similar level through the forecast period which is well below the replacement level of 2.1 children per woman. Oregon's fertility level is tracking below the national level.

Life Table survival rates are developed for the year 2010 and a new life table for 2020 will be developed when all necessary data becomes available. Male and female life expectancies for the 2010-2029 period are projected based on the past three decades of trends and national projected life expectancies. Gradual improvements in life expectancies are expected over the forecast period. At the same time, the difference between the male and female life expectancies will continue to shrink. The male life expectancy at births of 77.4 and the female life expectancy of 81.8 in 2010 are projected to improve to 79.4 years for males and 83.5 years for females by the year 2029. Life expectancy at birth declined during the current pandemic. However, it is expected to recover after 2021.

Estimates and forecasts of the number of net migrations are based on the residuals from the difference between population change and natural increase (births minus deaths) in a given forecast period. The migration forecasting model uses Oregon's employment, unemployment rates, income/wage data from Oregon and neighboring states, and past trends. Distribution of migrants by age and sex is based on detailed data from the American Community Survey. In the recent past, slowdown in Oregon's economy resulted in smaller net migration and slow population growth. Estimated population growth and net migration rates in 2010 and 2011 were the lowest in over two decades. Migration is intrinsically related to economy and employment situation of the state. Still, high unemployment and job loss in the recent past have impacted net migration and population growth, but not to the extent in the early 1980s. Main reason for this is the fact that other states of potential destination for Oregon out-migrants were not faring any better either, limiting the potential destination choices. The role of net migration in Oregon's population growth will get more prominence as the natural increase has begun to turn negative. The increasing excess of deaths over births will continue due to the rapid increase in the number of deaths associated with the aging population and decline in the number of births largely due to the decline in fertility rate associated with life-style choices. Such a trend was expected, but the COVID-19 has hastened the process. The annual net migration is expected to be low in the short run due to the COVID-19 effect. However, the migration is expected to recover after 2021. Between 2021 and 2029 net migration is expected to be in the range of 27,732 to 40,128, averaging 37,234 persons annually.

APPENDIX A: ECONOMIC FORECAST DETAIL

Table A.1 – Employment Forecast Tracking

Total Nonfarm Employment, 3rd quarter 2021
(Employment in thousands, Annualized Percent Change)

	Preliminary Estimate		Forecast		Forecast Error		Y/Y Change
	level	% ch	level	% ch	level	%	% ch
Total Nonfarm	1,887.1	5.9	1,901.8	8.3	(14.7)	(0.8)	4.2
Total Private	1,590.9	3.5	1,605.9	5.8	(15.0)	(0.9)	4.2
Mining and Logging	6.6	(7.0)	6.7	8.2	(0.2)	(2.3)	0.8
Construction	110.2	(1.4)	111.7	2.5	(1.5)	(1.3)	2.5
Manufacturing	187.4	1.7	187.0	3.3	0.3	0.2	2.6
Durable Goods	130.0	5.3	128.3	1.4	1.7	1.3	3.0
Wood Product	23.0	5.0	23.0	6.7	0.0	0.1	6.0
Metals and Machinery	36.5	5.5	35.6	2.6	0.9	2.5	2.6
Computer and Electronic Product	37.8	3.0	37.9	(0.1)	(0.1)	(0.3)	0.2
Transportation Equipment	10.8	(1.1)	10.6	(7.2)	0.2	1.8	1.5
Other Durable Goods	22.0	12.8	21.3	1.0	0.7	3.4	6.3
Nondurable Goods	57.3	(6.0)	58.7	7.5	(1.3)	(2.2)	1.9
Food	28.0	(9.3)	29.6	8.9	(1.6)	(5.3)	1.5
Other Nondurable Goods	29.4	(2.7)	29.1	6.2	0.3	0.9	2.3
Trade, Transportation & Utilities	361.5	(0.2)	361.4	0.4	0.1	0.0	3.5
Retail Trade	205.9	(10.2)	208.8	0.1	(3.0)	(1.4)	2.2
Wholesale Trade	74.8	3.9	74.8	2.4	(0.0)	(0.0)	2.0
Transportation, Warehousing & Utilities	76.3	(3.3)	77.8	(0.5)	(1.5)	(1.9)	1.4
Information	35.3	5.2	34.2	2.1	1.1	3.1	7.5
Financial Activities	103.6	3.3	103.3	1.2	0.3	0.3	2.4
Professional & Business Services	250.5	2.8	257.0	10.7	(6.5)	(2.5)	4.7
Educational & Health Services	301.8	1.7	306.9	7.1	(5.1)	(1.7)	2.5
Educational Services	33.0	3.7	36.3	29.9	(3.3)	(9.0)	7.0
Health Services	266.0	(3.9)	270.6	4.4	(4.6)	(1.7)	0.7
Leisure and Hospitality	180.0	6.2	176.6	13.9	3.5	2.0	15.1
Other Services	59.1	(1.5)	61.0	13.6	(1.9)	(3.2)	3.3
Government	296.2	20.6	295.9	23.6	0.4	0.1	4.2
Federal	28.5	(9.6)	28.4	(9.1)	0.0	0.2	(6.2)
State	42.2	(6.2)	42.9	0.7	(0.6)	(1.5)	2.3
State Education	1.0	63.6	0.8	0.8	0.1	17.6	11.1
Local	225.5	31.6	224.6	34.0	1.0	0.4	6.1
Local Education	132.5	56.4	131.5	55.4	1.0	0.8	9.5

Table A.2 – Short-Term Oregon Economic Summary

Oregon Forecast Summary

	Quarterly					Annual					
	2021:3	**2021:4**	**2022:1**	**2022:2**	**2022:3**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Personal Income ($ billions)											
Nominal Personal Income	251.7	250.5	251.3	254.9	258.5	221.2	238.8	254.9	256.6	270.9	285.6
% change	3.5	(1.8)	1.2	5.8	5.7	4.6	8.0	6.7	0.6	5.6	5.5
Real Personal Income (base year=2012)	216.5	214.1	213.7	215.6	217.5	201.2	214.7	221.2	216.5	224.1	231.6
% change	(1.7)	(4.3)	(0.8)	3.6	3.7	3.1	6.7	3.0	(2.1)	3.5	3.3
Nominal Wages and Salaries	126.5	128.2	130.4	132.2	134.1	112.8	115.3	124.3	133.2	141.0	148.6
% change	13.0	5.4	7.0	5.7	5.8	5.2	2.2	7.9	7.1	5.9	5.3
Other Indicators											
Per Capita Income ($1,000)	58.9	58.6	58.7	59.4	60.1	52.5	56.3	59.8	59.7	62.5	65.4
% change	2.8	(2.4)	0.5	5.0	4.9	3.7	7.2	6.2	(0.1)	4.7	4.6
Average Wage rate ($1,000)	65.9	66.6	67.1	67.5	68.0	57.4	62.7	65.8	67.8	70.5	73.4
% change	2.1	4.6	2.6	2.4	3.3	3.8	9.3	5.0	3.0	3.9	4.2
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.21	4.24	4.27	4.30	4.33	4.37
% change	0.6	0.7	0.8	0.7	0.8	0.9	0.7	0.5	0.7	0.8	0.8
Housing Starts (Thousands)	22.4	21.6	21.2	21.2	21.2	20.7	18.1	21.3	21.1	21.6	22.4
% change	4.0	(13.6)	(7.7)	0.7	0.7	5.6	(12.5)	17.5	(0.6)	2.2	3.5
Unemployment Rate	5.6	5.0	4.7	4.4	4.3	3.7	7.6	5.6	4.4	3.9	3.9
Point Change	(0.2)	(0.6)	(0.3)	(0.3)	(0.1)	(0.3)	3.9	(2.0)	(1.2)	(0.5)	(0.0)
Employment (Thousands)											
Total Nonfarm	1,887.1	1,910.9	1,931.3	1,946.8	1,959.1	1,954.3	1,829.4	1,871.6	1,951.6	1,989.6	2,012.3
% change	5.9	5.1	4.3	3.3	2.5	1.6	(6.4)	2.3	4.3	1.9	1.1
Private Nonfarm	1,590.9	1,612.5	1,630.8	1,646.1	1,657.5	1,655.9	1,544.4	1,583.1	1,650.5	1,686.6	1,707.8
% change	3.5	5.5	4.6	3.8	2.8	1.7	(6.7)	2.5	4.3	2.2	1.3
Construction	110.2	110.8	111.1	111.2	111.4	109.6	108.1	110.4	111.3	111.5	111.9
% change	(1.4)	2.0	1.1	0.5	0.4	3.9	(1.4)	2.2	0.8	0.2	0.4
Manufacturing	187.4	189.0	190.5	191.7	192.9	198.1	185.4	186.7	192.3	195.9	196.4
% change	1.7	3.6	3.2	2.5	2.6	1.5	(6.4)	0.7	3.0	1.9	0.2
Durable Manufacturing	130.0	129.9	130.5	131.0	131.5	137.1	128.3	128.8	131.2	133.2	133.5
% change	5.3	(0.3)	1.8	1.5	1.6	1.1	(6.4)	0.4	1.9	1.5	0.2
Wood Product Manufacturing	23.0	22.9	23.0	22.9	22.9	23.2	22.0	22.8	22.9	22.9	23.0
% change	5.0	(1.0)	0.4	(0.8)	(0.6)	(1.4)	(5.4)	3.7	0.5	0.1	0.6
High Tech Manufacturing	37.8	37.7	37.8	37.8	37.9	38.6	37.9	37.7	37.9	38.1	37.9
% change	3.0	(0.2)	0.3	0.8	0.9	1.8	(1.8)	(0.7)	0.7	0.5	(0.4)
Transportation Equipment	10.8	10.8	11.0	11.3	11.7	12.6	10.9	10.8	11.5	12.3	12.3
% change	(1.1)	(0.5)	7.2	11.9	13.8	3.8	(13.4)	(1.0)	6.3	7.2	0.1
Nondurable Manufacturing	57.3	59.1	60.0	60.7	61.4	61.1	57.1	57.9	61.0	62.7	62.9
% change	(6.0)	12.9	6.2	4.8	4.7	2.4	(6.5)	1.5	5.4	2.7	0.3
Private nonmanufacturing	1,408.7	1,423.5	1,440.3	1,454.4	1,464.6	1,457.6	1,358.9	1,399.4	1,458.2	1,490.7	1,511.4
% change	1.7	4.3	4.8	4.0	2.8	1.7	(6.8)	3.0	4.2	2.2	1.4
Retail Trade	205.9	207.9	208.7	209.8	209.9	210.1	200.6	208.4	209.6	210.2	210.7
% change	(10.2)	4.0	1.5	2.2	0.1	(0.6)	(4.5)	3.8	0.6	0.3	0.2
Wholesale Trade	74.8	75.1	75.4	76.4	77.1	76.6	74.2	74.5	76.6	78.1	78.8
% change	3.9	1.7	1.5	5.7	3.5	1.2	(3.1)	0.5	2.8	1.9	0.9
Information	35.3	35.4	35.5	35.5	35.7	35.1	33.2	34.8	35.6	36.1	36.7
% change	5.2	1.4	0.6	0.7	1.7	2.2	(5.3)	4.8	2.2	1.4	1.7
Professional and Business Services	250.5	253.1	255.4	257.9	260.5	254.7	242.8	249.5	259.3	270.0	276.6
% change	2.8	4.2	3.6	3.9	4.2	2.0	(4.7)	2.8	3.9	4.1	2.4
Health Services	266.0	273.1	279.6	281.8	283.8	275.4	264.7	268.2	282.5	287.0	290.5
% change	(3.9)	11.2	9.8	3.3	2.8	2.4	(3.9)	1.3	5.4	1.6	1.2
Leisure and Hospitality	180.0	185.1	190.5	195.6	198.4	213.8	162.3	172.5	196.4	205.7	210.2
% change	6.2	11.8	12.1	11.1	5.9	1.2	(24.1)	6.3	13.9	4.7	2.2
Government	296.2	298.4	300.4	300.7	301.6	298.4	285.0	288.5	301.2	303.0	304.5
% change	20.6	3.0	2.7	0.3	1.2	1.2	(4.5)	1.3	4.4	0.6	0.5

Table A.3 – Oregon Economic Forecast Change

Oregon Forecast Change (Current vs. Last)

	Quarterly					Annual					
	2021:3	**2021:4**	**2022:1**	**2022:2**	**2022:3**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Personal Income ($ billions)											
Nominal Personal Income	251.7	250.5	251.3	254.9	258.5	221.2	238.8	254.9	256.6	270.9	285.6
% change	0.5	(0.6)	(1.4)	(1.6)	(1.5)	(1.4)	(1.1)	(0.8)	(1.5)	(1.0)	(0.3)
Real Personal Income (base year=2012)	216.5	214.1	213.7	215.6	217.5	201.2	214.7	221.2	216.5	224.1	231.6
% change	(0.3)	(1.7)	(2.5)	(2.8)	(2.8)	(1.5)	(1.2)	(1.3)	(2.7)	(2.4)	(1.8)
Nominal Wages and Salaries	126.5	128.2	130.4	132.2	134.1	112.8	115.3	124.3	133.2	141.0	148.6
% change	2.2	1.7	1.8	1.6	1.4	0.3	1.2	1.3	1.5	1.6	2.0
Other Indicators											
Per Capita Income ($1,000)	58.9	58.6	58.7	59.4	60.1	52.5	56.3	59.8	59.7	62.5	65.4
% change	0.3	(0.9)	(1.6)	(1.8)	(1.8)	(1.5)	(1.2)	(1.0)	(1.7)	(1.3)	(0.6)
Average Wage rate ($1,000)	65.9	66.6	67.1	67.5	68.0	57.4	62.7	65.8	67.8	70.5	73.4
% change	1.9	2.3	2.2	1.8	1.6	0.3	1.0	1.2	1.8	1.7	2.0
Population (Millions)	4.27	4.28	4.28	4.3	4.3	4.21	4.24	4.27	4.30	4.33	4.37
% change	0.2	0.3	0.3	0.3	0.3	0.1	0.1	0.2	0.3	0.3	0.3
Housing Starts (Thousands)	22.4	21.6	21.2	21.2	21.2	20.7	18.1	21.3	21.1	21.6	22.4
% change	8.0	6.5	5.1	5.8	5.1	(0.0)	(0.1)	3.4	4.2	(0.7)	(0.2)
Unemployment Rate	5.6	5.0	4.7	4.4	4.3	3.7	7.6	5.6	4.4	3.9	3.9
Point Change	0.0	(0.6)	(0.7)	(0.9)	(0.7)	0.0	0.0	(0.2)	(0.7)	(0.1)	0.0
Employment (Thousands)											
Total Nonfarm	1,887.1	1,910.9	1,931.3	1,946.8	1,959.1	1,954.3	1,829.4	1,871.6	1,951.6	1,989.6	2,012.3
% change	(0.8)	(0.6)	(0.4)	(0.3)	(0.2)	0.0	0.1	(0.2)	(0.3)	(0.1)	(0.1)
Private Nonfarm	1,590.9	1,612.5	1,630.8	1,646.1	1,657.5	1,655.9	1,544.4	1,583.1	1,650.5	1,686.6	1,707.8
% change	(0.9)	(0.6)	(0.5)	(0.3)	(0.3)	0.0	0.1	(0.3)	(0.3)	(0.2)	(0.1)
Construction	110.2	110.8	111.1	111.2	111.4	109.6	108.1	110.4	111.3	111.5	111.9
% change	(1.3)	(0.8)	(0.4)	(0.2)	(0.0)	0.0	(0.0)	(0.5)	(0.1)	0.1	0.1
Manufacturing	187.4	189.0	190.5	191.7	192.9	198.1	185.4	186.7	192.3	195.9	196.4
% change	0.2	0.5	0.6	0.7	0.7	0.0	0.0	0.4	0.7	0.8	0.7
Durable Manufacturing	130.0	129.9	130.5	131.0	131.5	137.1	128.3	128.8	131.2	133.2	133.5
% change	1.3	1.0	1.1	1.1	1.1	0.0	0.0	0.7	1.0	1.0	0.8
Wood Product Manufacturing	23.0	22.9	23.0	22.9	22.9	23.2	22.0	22.8	22.9	22.9	23.0
% change	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.2	0.1	0.1	0.1
High Tech Manufacturing	37.8	37.7	37.8	37.8	37.9	38.6	37.9	37.7	37.9	38.1	37.9
% change	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	0.0	(0.0)	(0.3)	(0.3)	(0.3)	(0.3)
Transportation Equipment	10.8	10.8	11.0	11.3	11.7	12.6	10.9	10.8	11.5	12.3	12.3
% change	1.8	0.5	0.5	0.5	0.5	0.0	(0.1)	0.4	0.5	0.5	0.5
Nondurable Manufacturing	57.3	59.1	60.0	60.7	61.4	61.1	57.1	57.9	61.0	62.7	62.9
% change	(2.2)	(0.7)	(0.3)	(0.2)	0.1	0.0	0.0	(0.4)	0.0	0.6	0.4
Private nonmanufacturing	1,408.7	1,423.5	1,440.3	1,454.4	1,464.6	1,457.6	1,358.9	1,399.4	1,458.2	1,490.7	1,511.4
% change	(0.7)	(0.8)	(0.6)	(0.4)	(0.4)	(0.0)	0.1	(0.1)	(0.5)	(0.3)	(0.1)
Retail Trade	205.9	207.9	208.7	209.8	209.9	210.1	200.6	208.4	209.6	210.2	210.7
% change	(1.4)	(0.7)	(0.5)	0.0	0.0	0.0	(0.1)	(0.2)	(0.1)	0.0	0.0
Wholesale Trade	74.8	75.1	75.4	76.4	77.1	76.6	74.2	74.5	76.6	78.1	78.8
% change	(0.0)	(0.6)	(1.0)	(0.8)	(0.7)	0.0	(0.1)	(0.2)	(0.8)	(0.6)	0.3
Information	35.3	35.4	35.5	35.5	35.7	35.1	33.2	34.8	35.6	36.1	36.7
% change	3.1	3.1	3.1	2.6	2.2	0.0	0.0	2.6	2.7	2.9	2.6
Professional and Business Services	250.5	253.1	255.4	257.9	260.5	254.7	242.8	249.5	259.3	270.0	276.6
% change	(2.5)	(2.0)	(1.7)	(1.6)	(1.4)	0.0	0.0	(1.2)	(1.5)	(1.0)	(0.9)
Health Services	266.0	273.1	279.6	281.8	283.8	275.4	264.7	268.2	282.5	287.0	290.5
% change	(1.7)	(1.0)	0.7	0.8	0.7	(0.0)	0.0	(0.5)	0.6	0.3	0.2
Leisure and Hospitality	180.0	185.1	190.5	195.6	198.4	213.8	162.3	172.5	196.4	205.7	210.2
% change	2.0	1.4	(0.7)	(0.5)	(0.5)	(0.0)	0.5	2.1	(0.6)	(0.5)	(0.4)
Government	296.2	298.4	300.4	300.7	301.6	298.4	285.0	288.5	301.2	303.0	304.5
% change	0.1	(0.7)	(0.2)	(0.1)	(0.1)	(0.0)	0.1	0.1	(0.1)	(0.0)	(0.0)

Table A.4 – Annual Economic Forecast

Dec 2021 - Personal Income

(Billions of Current Dollars)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Personal Income*												
Oregon	221.2	238.8	254.9	256.6	270.9	285.6	301.3	317.9	335.0	353.0	371.7	390.7
% Ch	4.6	8.0	6.7	0.6	5.6	5.5	5.5	5.5	5.4	5.4	5.3	5.1
U.S.	18,424.4	19,627.6	20,891.7	21,008.2	22,082.0	23,260.4	24,493.7	25,773.8	27,090.3	28,459.2	29,869.5	31,317.5
% Ch	4.1	6.5	6.4	0.6	5.1	5.3	5.3	5.2	5.1	5.1	5.0	4.8
Wage and Salary												
Oregon	112.8	115.3	124.3	133.2	141.0	148.6	156.1	163.7	171.8	180.2	188.9	198.0
% Ch	5.2	2.2	7.9	7.1	5.9	5.3	5.1	4.9	4.9	4.9	4.8	4.8
U.S.	9,323.5	9,444.1	10,199.7	10,948.1	11,573.3	12,161.3	12,757.2	13,372.1	14,012.1	14,676.8	15,372.7	16,104.1
% Ch	4.8	1.3	8.0	7.3	5.7	5.1	4.9	4.8	4.8	4.7	4.7	4.8
Other Labor Income												
Oregon	27.2	27.8	29.7	31.4	33.4	35.3	37.2	39.2	41.2	43.3	45.6	47.9
% Ch	3.5	2.1	7.1	5.7	6.2	5.7	5.5	5.3	5.2	5.1	5.1	5.1
U.S.	1,474.6	1,464.4	1,527.2	1,610.7	1,702.8	1,789.3	1,877.0	1,967.4	2,061.6	2,159.3	2,261.7	2,369.3
% Ch	2.8	(0.7)	4.3	5.5	5.7	5.1	4.9	4.8	4.8	4.7	4.7	4.8
Nonfarm Proprietor's Income												
Oregon	18.7	19.1	19.8	21.4	23.1	24.8	26.4	28.1	29.7	31.4	33.2	35.0
% Ch	0.5	1.9	3.7	8.4	7.8	7.2	6.5	6.6	5.6	5.5	5.9	5.4
U.S.	1,560.5	1,579.9	1,683.5	1,742.4	1,849.6	1,988.6	2,119.9	2,238.8	2,341.3	2,443.8	2,552.4	2,665.0
% Ch	1.2	1.2	6.6	3.5	6.2	7.5	6.6	5.6	4.6	4.4	4.4	4.4
Dividend, Interest and Rent												
Oregon	44.2	44.1	44.6	46.5	49.1	51.6	54.3	57.6	61.1	64.6	68.2	71.7
% Ch	3.9	(0.1)	1.1	4.4	5.5	5.2	5.2	6.0	6.1	5.8	5.6	5.2
U.S.	3,660.1	3,623.7	3,660.0	3,796.8	3,983.2	4,190.4	4,421.5	4,685.0	4,961.9	5,245.2	5,528.9	5,805.8
% Ch	3.1	(1.0)	1.0	3.7	4.9	5.2	5.5	6.0	5.9	5.7	5.4	5.0
Transfer Payments												
Oregon	42.6	56.8	62.6	52.5	54.6	57.5	61.0	64.6	68.4	72.5	76.7	81.0
% Ch	5.7	33.4	10.3	(16.2)	4.1	5.2	6.0	5.9	5.9	6.0	5.9	5.5
U.S.	3,083.1	4,181.3	4,514.1	3,710.1	3,815.3	4,002.8	4,230.8	4,469.1	4,718.5	4,988.0	5,262.3	5,538.2
% Ch	5.4	35.6	8.0	(17.8)	2.8	4.9	5.7	5.6	5.6	5.7	5.5	5.2
Contributions for Social Security												
Oregon	19.5	20.2	21.7	23.1	24.6	26.0	27.3	28.6	30.1	31.6	33.2	34.8
% Ch	4.9	3.4	7.7	6.6	6.4	5.7	4.9	4.8	5.0	5.0	5.0	4.9
U.S.	771.8	795.8	856.9	916.1	959.3	1,000.4	1,043.4	1,090.2	1,141.0	1,195.6	1,255.3	1,316.4
% Ch	4.9	3.1	7.7	6.9	4.7	4.3	4.3	4.5	4.7	4.8	5.0	4.9
Residence Adjustment												
Oregon	(5.2)	(5.5)	(5.9)	(6.2)	(6.5)	(6.8)	(7.1)	(7.5)	(7.8)	(8.2)	(8.5)	(8.9)
% Ch	1.7	5.5	6.3	5.7	5.1	5.0	4.7	4.5	4.5	4.5	4.5	4.5
Farm Proprietor's Income												
Oregon	0.5	1.5	1.5	0.9	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
% Ch	103.8	209.0	(2.3)	(41.9)	(14.3)	1.7	(0.8)	(2.8)	(0.1)	1.5	0.5	0.6
Per Capita Income (Thousands of $)												
Oregon	52.5	56.3	59.8	59.7	62.5	65.4	68.4	71.6	74.8	78.2	81.6	85.1
% Ch	3.7	7.2	6.2	(0.1)	4.7	4.6	4.6	4.6	4.5	4.5	4.4	4.3
U.S.	55.8	59.2	62.9	63.1	66.0	69.2	72.4	75.8	79.3	82.8	86.5	90.2
% Ch	3.5	6.2	6.3	0.2	4.6	4.8	4.7	4.7	4.5	4.5	4.4	4.3

* Personal Income includes all classes of income minus Contributions for Social Security

Dec 2021 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Total Nonfarm												
Oregon	1,954.3	1,829.4	1,871.6	1,951.6	1,989.6	2,012.3	2,029.1	2,043.1	2,059.2	2,076.0	2,090.5	2,104.1
% Ch	1.6	(6.4)	2.3	4.3	1.9	1.1	0.8	0.7	0.8	0.8	0.7	0.7
U.S.	150.9	142.3	146.0	151.3	154.2	155.7	156.6	157.3	158.1	158.8	159.6	160.4
% Ch	1.3	(5.7)	2.6	3.6	1.9	1.0	0.6	0.5	0.5	0.5	0.5	0.5
Private Nonfarm												
Oregon	1,655.9	1,544.4	1,583.1	1,650.5	1,686.6	1,707.8	1,723.2	1,735.9	1,750.3	1,765.7	1,778.8	1,790.5
% Ch	1.7	(6.7)	2.5	4.3	2.2	1.3	0.9	0.7	0.8	0.9	0.7	0.7
U.S.	128.3	120.3	124.1	128.7	131.3	132.7	133.5	134.1	134.8	135.4	136.0	136.7
% Ch	1.5	(6.2)	3.1	3.7	2.1	1.0	0.6	0.5	0.5	0.5	0.5	0.5
Mining and Logging												
Oregon	6.9	6.6	6.7	6.7	6.7	6.8	6.9	7.0	7.0	7.0	7.0	7.0
% Ch	(4.4)	(4.7)	1.4	1.0	(0.2)	1.0	1.2	1.1	0.7	0.2	0.3	0.1
U.S.	0.7	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
% Ch	0.0	(14.7)	2.0	6.7	1.6	1.4	0.4	0.5	0.4	1.0	1.6	1.1
Construction												
Oregon	109.6	108.1	110.4	111.3	111.5	111.9	112.5	113.0	113.6	114.1	114.6	115.1
% Ch	3.9	(1.4)	2.2	0.8	0.2	0.4	0.5	0.4	0.5	0.4	0.4	0.4
U.S.	7.5	7.3	7.4	7.5	7.5	7.5	7.6	7.6	7.7	7.7	7.7	7.8
% Ch	2.8	(2.9)	2.0	0.4	0.8	0.1	0.5	0.8	0.4	0.4	0.8	0.8
Manufacturing												
Oregon	198.1	185.4	186.7	192.3	195.9	196.4	195.7	195.2	195.3	195.9	196.4	196.6
% Ch	1.5	(6.4)	0.7	3.0	1.9	0.2	(0.3)	(0.3)	0.0	0.3	0.3	0.1
U.S.	12.8	12.2	12.4	12.5	12.6	12.6	12.4	12.3	12.3	12.2	12.1	12.0
% Ch	1.0	(4.9)	1.5	1.4	0.8	(0.5)	(1.1)	(1.0)	(0.5)	(0.6)	(0.6)	(0.6)
Durable Manufacturing												
Oregon	137.1	128.3	128.8	131.2	133.2	133.5	133.0	132.2	132.0	132.3	132.5	132.5
% Ch	1.1	(6.4)	0.4	1.9	1.5	0.2	(0.4)	(0.6)	(0.1)	0.2	0.1	0.0
U.S.	8.0	7.6	7.7	7.8	7.9	7.9	7.8	7.7	7.7	7.6	7.6	7.6
% Ch	1.2	(5.7)	1.3	1.6	1.3	(0.2)	(1.1)	(1.1)	(0.4)	(0.5)	(0.5)	(0.6)
Wood Products												
Oregon	23.2	22.0	22.8	22.9	22.9	23.0	23.1	23.1	23.2	23.3	23.4	23.4
% Ch	(1.4)	(5.4)	3.7	0.5	0.1	0.6	0.1	0.2	0.3	0.6	0.4	0.1
U.S.	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
% Ch	0.7	(3.3)	2.8	(2.8)	(6.9)	1.7	2.0	0.2	(2.5)	(1.2)	1.1	1.6
Metal and Machinery												
Oregon	40.2	36.6	36.0	36.8	37.2	37.4	37.5	37.4	37.4	37.4	37.5	37.5
% Ch	2.2	(9.0)	(1.5)	2.1	1.2	0.5	0.2	(0.1)	(0.1)	0.1	0.2	0.2
U.S.	3.0	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
% Ch	1.1	(6.3)	1.0	3.1	0.2	(0.3)	(0.4)	(0.1)	0.5	(0.1)	(0.2)	(0.2)
Computer and Electronic Products												
Oregon	38.6	37.9	37.7	37.9	38.1	37.9	37.6	37.4	37.2	37.1	37.1	37.1
% Ch	1.8	(1.8)	(0.7)	0.7	0.5	(0.4)	(0.9)	(0.6)	(0.4)	(0.2)	(0.1)	(0.1)
U.S.	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.0	1.0	1.0
% Ch	2.0	(0.3)	1.1	(1.2)	(1.1)	0.2	(0.0)	(0.6)	(0.6)	(1.1)	(1.3)	(1.1)
Transportation Equipment												
Oregon	12.6	10.9	10.8	11.5	12.3	12.3	12.1	12.1	12.0	12.1	12.0	11.9
% Ch	3.8	(13.4)	(1.0)	6.3	7.2	0.1	(1.5)	(0.6)	(0.2)	0.1	(0.5)	(1.1)
U.S.	1.7	1.6	1.6	1.6	1.8	1.8	1.8	1.7	1.6	1.6	1.6	1.5
% Ch	1.6	(8.6)	0.9	2.4	9.9	0.7	(2.9)	(3.9)	(2.3)	(1.7)	(2.1)	(2.6)
Other Durables												
Oregon	22.4	20.9	21.6	22.2	22.7	22.8	22.7	22.2	22.2	22.4	22.5	22.6
% Ch	(0.7)	(6.6)	3.0	3.0	2.2	0.5	(0.4)	(2.1)	(0.0)	0.7	0.4	0.4
U.S.	2.2	2.1	2.2	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
% Ch	0.6	(5.2)	2.3	0.4	(2.5)	(1.0)	(1.1)	(0.5)	(0.0)	0.2	0.6	0.7
Nondurable Manufacturing												
Oregon	61.1	57.1	57.9	61.0	62.7	62.9	62.8	63.0	63.3	63.6	63.9	64.1
% Ch	2.4	(6.5)	1.5	5.4	2.7	0.3	(0.2)	0.4	0.4	0.5	0.5	0.3
U.S.	4.8	4.6	4.7	4.7	4.7	4.7	4.6	4.6	4.6	4.5	4.5	4.5
% Ch	0.8	(3.7)	1.8	1.0	(0.1)	(0.9)	(0.9)	(0.9)	(0.6)	(0.6)	(0.7)	(0.6)
Food Manufacturing												
Oregon	29.9	28.0	28.6	29.7	30.1	30.2	30.3	30.4	30.4	30.5	30.6	30.7
% Ch	0.1	(6.3)	2.0	4.1	1.4	0.3	0.2	0.3	0.3	0.2	0.5	0.3
U.S.	1.6	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
% Ch	1.5	(1.6)	1.4	0.0	1.1	0.6	0.9	0.8	1.0	0.7	0.5	0.7
Other Nondurable												
Oregon	31.2	29.1	29.4	31.3	32.6	32.7	32.5	32.7	32.8	33.1	33.3	33.3
% Ch	4.7	(6.7)	1.1	6.5	4.0	0.4	(0.6)	0.5	0.5	0.9	0.5	0.2
U.S.	3.1	3.0	3.0	3.1	3.1	3.0	3.0	2.9	2.9	2.8	2.8	2.7
% Ch	0.4	(4.8)	1.9	1.5	(0.7)	(1.7)	(1.9)	(1.8)	(1.5)	(1.4)	(1.4)	(1.3)
Trade, Transportation, and Utilities												
Oregon	357.2	349.6	361.1	364.0	368.9	372.1	374.7	376.8	378.1	378.9	379.2	379.3
% Ch	1.3	(2.1)	3.3	0.8	1.3	0.9	0.7	0.6	0.3	0.2	0.1	0.0
U.S.	27.7	26.6	27.4	27.6	27.4	27.2	27.0	26.9	26.7	26.5	26.4	26.3
% Ch	0.4	(4.1)	2.9	0.9	(0.8)	(0.9)	(0.7)	(0.3)	(0.6)	(0.7)	(0.6)	(0.2)

Dec 2021 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Retail Trade												
Oregon	210.1	200.6	208.4	209.6	210.2	210.7	211.1	211.4	211.8	212.2	212.4	212.6
% Ch	(0.6)	(4.5)	3.8	0.6	0.3	0.2	0.2	0.1	0.2	0.2	0.1	0.1
U.S.	15.6	14.9	15.3	15.0	14.4	13.9	13.4	13.1	12.9	12.8	12.7	12.7
% Ch	(1.0)	(4.9)	3.1	(2.3)	(3.8)	(3.4)	(3.5)	(2.1)	(1.6)	(1.1)	(0.7)	0.1
Wholesale Trade												
Oregon	76.6	74.2	74.5	76.6	78.1	78.8	79.6	80.2	80.7	81.0	81.2	81.2
% Ch	1.2	(3.1)	0.5	2.8	1.9	0.9	1.0	0.9	0.5	0.4	0.2	0.1
U.S.	5.9	5.6	5.7	6.0	6.2	6.4	6.5	6.6	6.7	6.6	6.6	6.5
% Ch	0.8	(4.2)	1.0	5.0	3.9	2.5	2.4	1.4	0.6	(0.4)	(0.7)	(0.7)
Transportation and Warehousing, and Utilities												
Oregon	70.5	74.5	76.9	77.8	80.6	82.6	84.0	85.2	85.7	85.7	85.6	85.5
% Ch	7.4	5.6	3.2	1.2	3.6	2.6	1.7	1.4	0.5	0.0	(0.1)	(0.1)
U.S.	6.2	6.1	6.3	6.7	6.8	6.9	7.0	7.1	7.2	7.1	7.1	7.1
% Ch	3.9	(2.0)	4.0	5.2	1.9	1.2	2.1	1.5	0.3	(0.2)	(0.4)	(0.4)
Information												
Oregon	35.1	33.2	34.8	35.6	36.1	36.7	37.0	37.1	37.3	37.5	37.6	37.8
% Ch	2.2	(5.3)	4.8	2.2	1.4	1.7	0.6	0.5	0.5	0.5	0.5	0.4
U.S.	2.9	2.7	2.7	2.8	2.9	3.0	3.0	3.0	3.0	3.0	3.0	2.9
% Ch	0.9	(5.8)	1.9	3.1	1.6	3.7	1.6	(0.5)	(0.6)	(0.7)	(0.8)	(0.4)
Financial Activities												
Oregon	103.5	101.7	103.0	104.6	104.8	105.2	105.4	105.2	105.4	105.5	105.4	104.9
% Ch	1.3	(1.8)	1.2	1.6	0.2	0.4	0.2	(0.2)	0.1	0.1	(0.1)	(0.4)
U.S.	8.8	8.7	8.8	9.1	9.1	9.2	9.3	9.3	9.2	9.1	9.1	9.0
% Ch	1.9	(0.3)	1.1	3.1	0.6	0.5	0.9	(0.1)	(0.8)	(0.6)	(0.6)	(0.8)
Professional and Business Services												
Oregon	254.7	242.8	249.5	259.3	270.0	276.6	281.9	286.5	292.4	299.0	304.5	309.6
% Ch	2.0	(4.7)	2.8	3.9	4.1	2.4	1.9	1.6	2.1	2.2	1.8	1.7
U.S.	21.3	20.3	20.9	22.4	23.1	23.5	23.9	24.2	24.6	25.0	25.4	25.7
% Ch	1.6	(4.8)	3.4	7.1	2.9	2.0	1.7	1.2	1.6	1.5	1.5	1.3
Education and Health Services												
Oregon	312.1	297.1	302.3	318.0	323.1	326.8	330.4	333.7	336.8	339.9	343.2	346.4
% Ch	2.2	(4.8)	1.8	5.2	1.6	1.2	1.1	1.0	0.9	0.9	1.0	0.9
U.S.	24.2	23.2	23.5	24.3	24.4	24.8	25.1	25.4	25.7	26.0	26.3	26.4
% Ch	2.2	(3.8)	1.3	3.3	0.5	1.4	1.2	1.3	1.2	1.1	0.9	0.7
Educational Services												
Oregon	36.6	32.1	32.9	35.4	36.1	36.3	36.4	36.4	36.4	36.3	36.2	36.1
% Ch	0.3	(12.4)	2.7	7.6	1.8	0.7	0.2	0.0	(0.1)	(0.2)	(0.2)	(0.3)
U.S.	3.7	3.5	3.5	3.8	3.8	3.8	3.8	3.9	3.9	3.9	3.9	3.9
% Ch	0.7	(7.6)	2.3	6.1	0.8	1.1	0.3	0.6	0.9	0.7	0.2	(0.2)
Health Care and Social Assistance												
Oregon	275.4	264.7	268.2	282.5	287.0	290.5	294.0	297.3	300.4	303.7	307.0	310.3
% Ch	2.4	(3.9)	1.3	5.4	1.6	1.2	1.2	1.1	1.1	1.1	1.1	1.1
U.S.	20.4	19.8	20.0	20.6	20.7	21.0	21.2	21.6	21.8	22.1	22.3	22.5
% Ch	2.5	(3.1)	1.1	2.8	0.5	1.4	1.4	1.4	1.3	1.2	1.0	0.8
Leisure and Hospitality												
Oregon	213.8	162.3	172.5	196.4	205.7	210.2	213.1	215.0	217.5	220.5	223.0	225.4
% Ch	1.2	(24.1)	6.3	13.9	4.7	2.2	1.4	0.9	1.2	1.4	1.2	1.1
U.S.	16.6	13.4	14.6	15.8	17.5	18.1	18.2	18.3	18.4	18.5	18.7	19.0
% Ch	1.8	(19.4)	9.5	7.6	10.9	3.5	0.7	0.4	0.5	0.8	1.2	1.2
Other Services												
Oregon	64.8	57.6	59.1	62.2	63.9	65.0	65.7	66.3	66.9	67.4	67.8	68.3
% Ch	0.6	(11.1)	2.6	5.2	2.7	1.8	1.1	0.9	0.9	0.8	0.6	0.6
U.S.	5.9	5.4	5.6	6.0	6.1	6.2	6.3	6.4	6.5	6.6	6.7	6.7
% Ch	1.0	(8.4)	4.6	5.5	2.4	1.7	2.1	1.9	1.4	1.2	0.9	0.6
Government												
Oregon	298.4	285.0	288.5	301.2	303.0	304.5	305.9	307.3	308.8	310.4	311.7	313.6
% Ch	1.2	(4.5)	1.3	4.4	0.6	0.5	0.5	0.5	0.5	0.5	0.4	0.6
U.S.	22.6	21.9	21.9	22.6	22.9	23.0	23.1	23.2	23.3	23.4	23.5	23.7
% Ch	0.7	(3.1)	(0.1)	3.3	1.2	0.5	0.5	0.5	0.5	0.5	0.5	0.8
Federal Government												
Oregon	28.5	29.2	28.8	28.4	28.4	28.3	28.3	28.3	28.3	28.2	28.2	29.0
% Ch	1.4	2.4	(1.4)	(1.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	2.8
U.S.	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0
% Ch	1.1	3.5	(1.5)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.5
State Government, Oregon												
State Total	40.9	41.4	42.5	42.3	42.7	43.4	43.9	44.4	44.9	45.6	46.0	46.4
% Ch	3.6	1.1	2.8	(0.6)	1.1	1.5	1.1	1.1	1.3	1.4	1.0	0.8
State Education	0.9	0.9	0.9	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9
% Ch	7.2	4.1	5.2	3.6	(2.1)	(1.6)	(1.5)	(1.5)	(1.0)	(0.8)	(0.3)	(0.5)
Local Government, Oregon												
Local Total	229.0	214.4	217.3	230.5	231.8	232.8	233.7	234.6	235.6	236.6	237.5	238.2
% Ch	0.8	(6.4)	1.3	6.1	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.3
Local Education	133.2	121.9	124.4	132.8	132.7	132.3	131.9	131.4	131.0	130.6	130.2	129.8
% Ch	0.3	(8.5)	2.1	6.7	(0.1)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)

Dec 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 $)	19,032.7	18,384.7	19,385.0	20,211.2	20,782.9	21,336.5	21,866.7	22,399.5	22,914.6	23,427.9	23,946.6	24,477.0
% Ch	2.3	(3.4)	5.4	4.3	2.8	2.7	2.5	2.4	2.3	2.2	2.2	2.2
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2012=100	112.3	113.7	118.1	121.8	124.4	127.4	130.5	133.7	136.9	140.2	143.5	146.8
% Ch	1.8	1.3	3.9	3.1	2.2	2.4	2.5	2.4	2.4	2.4	2.4	2.3
Personal Consumption Deflator,												
Chain Weight U.S., 2012=100	109.9	111.2	115.3	118.5	120.9	123.3	126.0	128.7	131.5	134.4	137.5	140.5
% Ch	1.5	1.2	3.6	2.8	2.0	2.0	2.1	2.1	2.2	2.2	2.3	2.2
CPI, Urban Consumers,												
1982-84=100												
West Region	270.3	275.1	287.4	298.8	306.0	313.7	321.9	330.5	339.5	349.0	358.8	368.9
% Ch	2.7	1.7	4.5	3.9	2.4	2.5	2.6	2.7	2.7	2.8	2.8	2.8
U.S.	255.7	258.8	270.0	278.1	283.9	289.9	296.5	303.3	310.4	317.9	325.7	333.6
% Ch	1.8	1.2	4.3	3.0	2.1	2.1	2.3	2.3	2.4	2.4	2.4	2.4
Oregon Average Wage												
Rate (Thous $)	57.4	62.7	65.8	67.8	70.5	73.4	76.5	79.7	83.0	86.4	89.9	93.7
% Ch	3.8	9.3	5.0	3.0	3.9	4.2	4.2	4.2	4.1	4.1	4.1	4.2
U.S. Average Wage												
Wage Rate (Thous $)	61.8	66.4	69.9	72.4	75.1	78.1	81.5	85.0	88.6	92.4	96.3	100.4
% Ch	3.4	7.5	5.2	3.6	3.7	4.1	4.3	4.3	4.3	4.3	4.2	4.2
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	438.2	474.3	558.8	607.1	625.1	639.2	654.2	671.1	690.1	712.5	736.7	761.7
% Ch	4.8	8.2	17.8	8.6	3.0	2.3	2.3	2.6	2.8	3.2	3.4	3.4
FHFA National Housing Price Index												
1991 Q1=100	270.9	292.1	341.7	376.7	392.8	401.7	407.5	412.9	419.5	428.3	439.2	450.8
% Ch	5.1	7.8	17.0	10.3	4.3	2.3	1.4	1.3	1.6	2.1	2.6	2.6
Housing Starts												
Oregon (Thous)	20.7	18.1	21.3	21.1	21.6	22.4	22.4	22.3	22.6	22.5	22.6	22.6
% Ch	5.6	(12.5)	17.5	(0.6)	2.2	3.5	0.3	(0.6)	1.2	(0.2)	0.3	(0.2)
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	12.8	(9.1)	(7.0)	(0.2)	(0.0)	(2.7)	(3.1)	(1.5)	(0.6)	(1.3)
Other Indicators												
Unemployment Rate (%)												
Oregon	3.7	7.6	5.6	4.4	3.9	3.9	4.0	4.1	4.1	4.1	4.1	4.1
Point Change	(0.3)	3.9	(2.0)	(1.2)	(0.5)	(0.0)	0.1	0.1	0.0	0.0	0.0	0.0
U.S.	3.7	8.1	5.5	4.1	3.6	3.6	3.7	3.9	4.0	4.1	4.2	4.2
Point Change	(0.2)	4.4	(2.6)	(1.4)	(0.5)	(0.0)	0.1	0.1	0.1	0.1	0.1	0.0
Industrial Production Index												
U.S, 2012 = 100	102.3	95.0	100.4	105.2	108.5	110.7	112.6	114.4	116.0	117.7	119.5	121.4
% Ch	(0.8)	(7.2)	5.7	4.8	3.1	2.1	1.7	1.6	1.4	1.4	1.5	1.6
Prime Rate (Percent)	5.3	3.5	3.3	3.3	3.5	4.1	4.8	5.4	5.6	5.8	5.8	5.8
% Ch	7.7	(32.9)	(8.3)	0.0	8.2	16.6	16.7	12.6	4.7	2.0	0.0	0.0
Population (Millions)												
Oregon	4.21	4.24	4.27	4.30	4.33	4.37	4.40	4.44	4.48	4.52	4.55	4.59
% Ch	0.9	0.7	0.5	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	3,693.2	3,731.8	3,698.4	3,729.4	3,745.9	3,765.3	3,783.4	3,781.4	3,780.2	3,779.0
% Ch	(12.9)	(4.6)	9.3	1.0	(0.9)	0.8	0.4	0.5	0.5	(0.1)	(0.0)	(0.0)

APPENDIX B: REVENUE FORECAST DETAIL

Table B.1 General Fund Revenue Statement

Table B.1
General Fund Revenue Statement -- 2021-23

		Forecasts Dated: 9/1/2021			Forecasts Dated: 12/1/2021			Difference	
	Estimate at COS 2021	2021-22	2022-23	Total 2021-23	2021-22	2022-23	Total 2021-23	12/1/2021 Less 9/1/2021	12/1/2021 Less COS
Taxes									
Personal Income Taxes	20,628,060,000	9,800,035,000	10,857,002,000	20,657,037,000	10,196,097,000	10,963,019,000	21,159,116,000	502,079,000	531,056,000
Film and Video and Transfer to Counties	(40,583,000)	(20,280,000)	(20,803,000)	(41,083,000)	(20,280,000)	(20,803,000)	(41,083,000)	0	(500,000)
Corporate Income Taxes	1,343,966,000	783,581,000	626,377,000	1,409,958,000	938,464,000	655,761,000	1,594,225,000	184,267,000	250,259,000
Transfer to Rainy Day Fund (Minimum Tax)	(56,001,000)	0	(58,238,000)	(58,238,000)	0	(64,922,000)	(64,922,000)	(6,684,000)	(8,921,000)
Insurance Taxes	135,086,000	69,807,000	69,403,000	139,210,000	69,912,000	69,403,000	139,315,000	105,000	4,229,000
Estate Taxes	443,848,000	216,265,000	227,583,000	443,848,000	227,242,000	229,583,000	456,825,000	12,977,000	12,977,000
Transfer to PERS UAL	(74,916,000)	0	(74,916,000)	(74,916,000)	0	(74,916,000)	(74,916,000)	0	0
Cigarette Taxes	44,903,000	22,502,000	22,203,000	44,705,000	22,933,000	22,203,000	45,136,000	431,000	233,000
Other Tobacco Products Taxes	65,129,000	32,465,000	32,664,000	65,129,000	32,634,000	32,664,000	65,298,000	169,000	169,000
Other Taxes	1,786,000	893,000	893,000	1,786,000	893,000	893,000	1,786,000	0	0
Fines and Fees									
State Court Fees	136,147,000	67,165,000	68,982,000	136,147,000	67,165,000	68,982,000	136,147,000	0	0
Secretary of State Fees	82,185,000	41,135,000	41,050,000	82,185,000	41,135,000	41,050,000	82,185,000	0	0
Criminal Fines & Assessments	27,202,000	13,976,000	13,876,000	27,852,000	13,976,000	13,876,000	27,852,000	0	650,000
Securities Fees	26,538,000	13,086,000	13,452,000	26,538,000	12,822,000	13,380,000	26,202,000	(336,000)	(336,000)
Central Service Charges	12,746,000	6,373,000	6,373,000	12,746,000	6,373,000	6,373,000	12,746,000	0	0
Liquor Apportionment	347,137,000	168,764,000	177,703,000	346,467,000	168,764,000	177,703,000	346,467,000	0	(670,000)
Interest Earnings	35,000,000	15,000,000	20,000,000	35,000,000	20,000,000	25,000,000	45,000,000	10,000,000	10,000,000
Miscellaneous Revenues	12,000,000	6,000,000	6,000,000	12,000,000	6,000,000	6,000,000	12,000,000	0	0
One-time Transfers	58,677,000	58,677,000	0	58,677,000	58,677,000	0	58,677,000	0	0
Gross General Fund Revenues	23,400,410,000	11,315,724,000	12,183,561,000	23,499,285,000	11,883,087,000	12,325,890,000	24,208,977,000	709,692,000	808,567,000
Total Transfers	(171,500,000)	(20,280,000)	(153,957,000)	(174,237,000)	(20,280,000)	(160,641,000)	(180,921,000)	(6,684,000)	(9,421,000)
Net General Fund Revenues	23,228,910,000	11,295,444,000	12,029,604,000	23,325,048,000	11,862,807,000	12,165,249,000	24,028,056,000	703,008,000	799,146,000
Plus Beginning Balance	3,025,585,699			3,704,322,241			3,704,322,241	0	678,736,542
Less Anticipated Administrative Actions*	(21,472,000)			(21,472,000)			(21,472,000)	0	0
Less Legislatively Adopted Actions**	(224,612,788)			(224,612,788)			(224,612,788)	0	0
Available Resources	26,008,410,911			26,783,285,453			27,486,293,453	703,008,000	1,477,882,542
Appropriations	25,445,991,039			25,445,991,039			25,445,991,039	0	0
Estimated Ending Balance	562,419,872			1,337,294,414			2,040,302,414	703,008,000	1,477,882,542

Table B.2 General Fund Revenue Forecast by Fiscal Year

TABLE B.2

General Fund Revenue Forecast

December 2021

($Millions)

Fiscal Years	2019-20 Fiscal Year	2020-21 Fiscal Year	2021-22 Fiscal Year	2022-23 Fiscal Year	2023-24 Fiscal Year	2024-25 Fiscal Year	2025-26 Fiscal Year	2026-27 Fiscal Year	2027-28 Fiscal Year	2028-29 Fiscal Year	2029-30 Fiscal Year	2030-31 Fiscal Year
Taxes												
Personal Income	7,212.2	12,834.8	10,196.1	10,963.0	12,419.5	12,470.3	13,468.2	14,096.2	15,029.0	15,963.9	17,101.5	18,064.2
Film and Video & Transfer to Counties	(20.1)	(20.2)	(20.3)	(20.8)	(21.3)	(17.9)	0.0	0.0	0.0	0.0	0.0	0.0
Corporate Excise & Income	488.3	1,553.1	938.5	655.8	774.4	827.4	925.1	1,009.8	1,048.1	1,120.0	1,201.5	1,276.5
Transfer to RDF & PERS UAL	0.0	(74.5)	0.0	(64.9)	0.0	(66.6)	0.0	(80.5)	0.0	(90.2)	0.0	(103.1)
Insurance	75.3	83.9	69.9	69.4	71.0	72.1	74.8	77.9	85.6	88.2	91.2	94.2
Estate	113.8	410.3	227.2	229.6	236.0	239.1	246.3	251.4	258.9	263.2	267.5	272.0
Transfer toPERS UAL	0.0	0.0	0.0	(74.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cigarette	30.5	24.6	22.9	22.2	22.0	21.5	20.9	20.5	20.1	19.8	19.5	19.2
Other Tobacco Products	30.9	30.4	32.6	32.7	32.7	32.9	32.9	33.1	33.1	33.0	32.9	32.9
Other Taxes	0.4	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Other Revenues												
Licenses and Fees	135.3	114.1	135.1	137.3	136.8	137.7	135.6	135.5	135.4	136.0	136.1	136.2
Charges for Services	5.7	5.7	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Liquor Apportionment	162.1	178.8	168.8	177.7	168.2	176.3	185.1	194.2	203.7	213.5	223.8	234.5
Interest Earnings	64.5	28.5	20.0	25.0	35.0	40.0	45.0	50.0	50.0	50.0	50.0	50.0
Others	20.4	165.4	64.7	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Gross General Fund	8,339.4	15,430.1	11,883.1	12,325.9	13,908.9	14,030.7	15,147.1	15,881.8	16,877.1	17,900.9	19,137.4	20,192.8
Net General Fund	8,319.3	15,335.4	11,862.8	12,165.2	13,887.5	13,946.2	15,147.1	15,801.3	16,877.1	17,810.7	19,137.4	20,089.7

Biennial Totals	2019-21 BN	Change (%)	2021-23 BN	Change (%)	2023-25 BN	Change (%)	2025-27 BN	Change (%)	2027-29 BN	Change (%)	2029-31 BN	Change (%)
Taxes												
Personal Income	20,047.0	6.5%	21,159.1	5.5%	24,889.8	17.6%	27,564.3	10.7%	30,992.9	12.4%	35,165.7	13.5%
Corporate Excise & Income	2,041.4	16.5%	1,594.2	-21.9%	1,601.8	0.5%	1,934.9	20.8%	2,168.1	12.1%	2,478.0	14.3%
Insurance	159.2	-0.7%	139.3	-12.5%	143.0	2.7%	152.7	6.8%	173.8	13.8%	185.4	6.6%
Estate Taxes	524.1	37.5%	456.8	-12.8%	475.1	4.0%	497.7	4.7%	522.1	4.9%	539.5	3.3%
Cigarette	55.1	-16.0%	45.1	-18.1%	43.5	-3.6%	41.3	-5.0%	39.9	-3.4%	38.7	-3.1%
Other Tobacco Products	61.3	-3.6%	65.3	6.5%	65.6	0.5%	66.0	0.6%	66.1	0.0%	65.8	-0.4%
Other Taxes	1.0	-49.4%	1.8	78.8%	1.8	0.0%	1.8	0.0%	1.8	0.0%	1.8	0.0%
Other Revenues												
Licenses and Fees	249.4	-3.7%	272.4	9.2%	274.5	0.8%	271.1	-1.2%	271.4	0.1%	272.3	0.3%
Charges for Services	11.5	5.5%	12.7	11.0%	12.7	0.0%	12.7	0.0%	12.7	0.0%	12.7	0.0%
Liquor Apportionment	340.9	15.8%	346.5	1.6%	344.5	-0.6%	379.3	10.1%	417.2	10.0%	458.3	9.9%
Interest Earnings	92.9	6.6%	45.0	-51.6%	75.0	66.7%	95.0	26.7%	100.0	5.3%	100.0	0.0%
Others	185.8	1121.7%	70.7	-62.0%	12.0	-83.0%	12.0	0.0%	12.0	0.0%	12.0	0.0%
Gross General Fund	23,769.5	8.5%	24,209.0	1.8%	27,939.5	15.4%	31,028.9	11.1%	34,778.0	12.1%	39,330.2	13.1%
Net General Fund	23,654.7	8.6%	24,028.1	1.6%	27,833.7	15.8%	30,948.4	11.2%	34,687.8	12.1%	39,227.1	13.1%

Table B.3 Summary of 2021 Legislative Session Adjustments

	21-23	23-25	25-27	Revenue Impact Statement
Personal Income Tax Impacts (millions)				
Tax Expenditure – HB 2433	-$68.5	-$149.5	-$165.1	HB 2433
EITC (Federal Reconnect) – HB 2457	-$13.0	-$0.4	-$0.4	HB 2457
Pass-Through Entity – SB 139	$41.7	$59.9	$64.2	SB 139
Personal Income Tax Total	**-$39.8**	**-$90.1**	**-$101.4**	
Corporate Income Tax Impacts (millions)				
Tax Expenditure – HB 2433	-$1.0	-$6.5	-$9.7	HB 2433
Broadcasters – SB 136	-$1.2	-$1.2	-$1.2	SB 136
Corporate Income Tax Total	**-$2.2**	**-$7.7**	**-$10.9**	
Other Tax/Revenue Impacts (millions)				
Criminal Fine Account, Traffic - HB 2137	-$0.8	-$0.3	$0.0	HB 2137
Criminal Fine Account, Photo Radar – HB 2530	$0.0	$4.8	$7.5	HB 2530
Criminal Fine Account, Filing Fee – SB 397	-$1.2	-$1.2	-$1.2	SB 397
Criminal Fine Account, Juvenile – SB 817	-$3.0	-$0.9	-$0.9	SB 817
Tax Court - HB 2178	-$0.2	-$0.2	-$0.2	HB 2178
Secretary of State Filing Fees – SB 25	$1.5	-$0.6	-$6.3	SB 25
OLCC, Retail Agents – HB 2740	-$7.6	-$8.0	-$8.4	HB 2740
OLCC, Retail Agents – SB 316	-$1.5	-$2.3	-$2.3	SB 316
Other Tax Total	**-$12.7**	**-$8.6**	**-$11.9**	

Table B.4 Oregon Personal Income Tax Revenue Forecast

TABLE B.4 **OREGON PERSONAL INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted **December 2021**

	2009:3	2009:4	2010:1	2010:2	FY 2010	2010:3	2010:4	2011:1	2011:2	FY 2011
WITHHOLDING	1,092,795	1,151,673	1,157,857	1,116,552	4,518,878	1,146,189	1,196,214	1,262,781	1,218,439	4,823,622
%CHYA	-6.0%	-2.6%	2.6%	2.5%	-1.0%	4.9%	3.9%	9.1%	9.1%	6.7%
EST. PAYMENTS	176,110	161,759	186,894	265,703	790,467	179,692	148,589	207,036	284,662	819,978
%CHYA	-33.4%	-7.5%	-14.0%	1.0%	-14.1%	2.0%	-8.1%	10.8%	7.1%	3.7%
FINAL PAYMENTS	63,363	77,013	105,745	515,262	761,383	62,259	81,728	114,877	607,592	866,456
%CHYA	-9.9%	-22.5%	1.6%	-2.8%	-5.3%	-1.7%	6.1%	8.6%	17.9%	13.8%
REFUNDS	96,477	188,704	459,550	380,459	1,125,190	92,291	151,515	432,478	340,652	1,016,937
%CHYA	4.8%	4.6%	2.6%	-5.9%	0.1%	-4.3%	-19.7%	-5.9%	-10.5%	-9.6%
OTHER	(138,521)	-	-	136,193	(2,328)	(136,193)	-	-	165,933	29,740
TOTAL	1,097,271	1,201,740	990,947	1,653,251	4,943,210	1,159,655	1,275,015	1,152,216	1,935,973	5,522,860
%CHYA	-10.2%	-5.9%	-1.2%	2.3%	-3.4%	5.7%	6.1%	16.3%	17.1%	11.7%

	2011:3	2011:4	2012:1	2012:2	FY 2012	2012:3	2012:4	2013:1	2013:2	FY 2013
WITHHOLDING	1,235,508	1,287,030	1,348,171	1,269,562	5,140,271	1,262,589	1,364,547	1,354,116	1,321,413	5,302,666
%CHYA	7.8%	7.6%	6.8%	4.2%	6.6%	2.2%	6.0%	0.4%	4.1%	3.2%
EST. PAYMENTS	194,674	185,239	199,238	299,646	878,797	205,533	159,104	278,341	321,896	964,874
%CHYA	8.3%	24.7%	-3.8%	5.3%	7.2%	5.6%	-14.1%	39.7%	7.4%	9.8%
FINAL PAYMENTS	85,889	87,233	117,628	627,762	918,512	72,224	91,338	123,456	785,542	1,072,560
%CHYA	38.0%	6.7%	2.4%	3.3%	6.0%	-15.9%	4.7%	5.0%	25.1%	16.8%
REFUNDS	64,687	156,272	530,800	360,618	1,112,377	52,211	109,503	536,506	383,176	1,081,397
%CHYA	-29.9%	3.1%	22.7%	5.9%	9.4%	-19.3%	-29.9%	1.1%	6.3%	-2.8%
OTHER	(165,933)	-	-	193,614	27,681	(193,614)	-	-	201,367	7,753
TOTAL	1,285,451	1,403,230	1,134,237	2,029,966	5,852,884	1,294,521	1,505,486	1,219,407	2,247,042	6,266,457
%CHYA	10.8%	10.1%	-1.6%	4.9%	6.0%	0.7%	7.3%	7.5%	10.7%	7.1%

	2013:3	2013:4	2014:1	2014:2	FY 2014	2014:3	2014:4	2015:1	2015:2	FY 2015
WITHHOLDING	1,333,946	1,435,630	1,442,755	1,420,313	5,632,644	1,455,822	1,523,453	1,576,188	1,505,337	6,060,801
%CHYA	5.7%	5.2%	6.5%	7.5%	6.2%	9.1%	6.1%	9.2%	6.0%	7.6%
EST. PAYMENTS	221,695	214,342	247,826	357,218	1,041,080	264,823	236,303	305,582	408,957	1,215,665
%CHYA	7.9%	34.7%	-11.0%	11.0%	7.9%	19.5%	10.2%	23.3%	14.5%	16.8%
FINAL PAYMENTS	83,096	112,495	139,923	730,795	1,066,309	92,647	144,239	156,188	847,330	1,240,403
%CHYA	15.1%	23.2%	13.3%	-7.0%	-0.6%	11.5%	28.2%	11.6%	15.9%	16.3%
REFUNDS	67,098	197,448	472,018	354,437	1,091,001	100,729	173,522	520,272	375,119	1,169,642
%CHYA	28.5%	80.3%	-12.0%	-7.5%	0.9%	50.1%	-12.1%	10.2%	5.8%	7.2%
OTHER	(201,367)	-	-	180,356	(21,011)	(180,356)	-	-	163,398	(16,959)
TOTAL	1,370,272	1,565,018	1,358,485	2,334,246	6,628,021	1,532,207	1,730,473	1,517,685	2,549,903	7,330,268
%CHYA	5.9%	4.0%	11.4%	3.9%	5.8%	11.8%	10.6%	11.7%	9.2%	10.6%

	2015:3	2015:4	2016:1	2016:2	FY 2016	2016:3	2016:4	2017:1	2017:2	FY 2017
WITHHOLDING	1,551,517	1,644,209	1,711,568	1,634,728	6,542,022	1,675,744	1,705,280	1,835,155	1,769,354	6,985,533
%CHYA	6.6%	7.9%	8.6%	8.6%	7.9%	8.0%	3.7%	7.2%	8.2%	6.8%
EST. PAYMENTS	309,470	141,009	327,008	423,839	1,201,325	300,866	319,225	382,445	450,241	1,452,777
%CHYA	16.9%	-40.3%	7.0%	5.7%	-0.5%	-2.8%	126.4%	17.0%	6.2%	20.9%
FINAL PAYMENTS[1]	99,618	321,345	141,818	813,132	1,375,913	103,631	144,248	175,235	919,186	1,342,301
%CHYA	7.5%	122.8%	-9.2%	-4.9%	10.2%	4.0%	-55.1%	23.6%	13.0%	-2.4%
REFUNDS	85,113	203,981	577,546	562,601	1,429,241	138,825	254,851	574,417	454,899	1,422,992
%CHYA	-15.5%	17.6%	11.0%	50.0%	22.2%	63.1%	24.9%	-0.5%	-19.1%	-0.4%
OTHER	(163,398)	-	-	236,108	72,710	(236,108)	-	-	192,251	(43,856)
TOTAL	1,712,094	1,902,583	1,602,848	2,545,205	7,762,729	1,705,308	1,913,902	1,818,419	2,876,134	8,313,763
%CHYA	11.7%	9.9%	5.6%	-0.2%	5.9%	-0.4%	0.6%	13.4%	13.0%	7.1%

	2017:3	2017:4	2018:1	2018:2	FY 2018	2018:3	2018:4	2019:1	2019:2	FY 2019
WITHHOLDING	1,748,844	1,836,249	2,011,564	1,851,177	7,447,834	1,925,880	2,039,120	2,079,900	1,999,015	8,043,914
%CHYA	4.4%	7.7%	9.6%	4.6%	6.6%	10.1%	11.0%	3.4%	8.0%	8.0%
EST. PAYMENTS	321,032	451,037	464,534	512,671	1,749,274	367,772	284,002	321,858	532,273	1,505,905
%CHYA	6.7%	41.3%	21.5%	13.9%	20.4%	14.6%	-37.0%	-30.7%	3.8%	-13.9%
FINAL PAYMENTS[1]	92,364	169,785	174,096	878,587	1,314,832	104,644	156,592	225,515	1,385,562	1,872,312
%CHYA	-10.9%	17.7%	-0.6%	-4.4%	-2.0%	13.3%	-7.8%	29.5%	57.7%	42.4%
REFUNDS	133,143	266,467	686,100	610,486	1,696,196	140,701	335,635	546,225	445,573	1,468,133
%CHYA	-4.1%	4.6%	19.4%	34.2%	19.2%	5.7%	26.0%	-20.4%	-27.0%	-13.4%
OTHER	(192,251)	-	-	237,300	45,049	(237,300)	-	-	222,477	(14,823)
TOTAL	1,836,845	2,190,604	1,964,094	2,869,249	8,860,793	2,020,295	2,144,078	2,081,049	3,693,754	9,939,176
%CHYA	7.7%	14.5%	8.0%	-0.2%	6.6%	10.0%	-2.1%	6.0%	28.7%	12.2%

Note: "Other" includes July withholding accrued to June.
Tax law impacts are reflected in the collections numbers to produce more meaningful projections.

TABLE B.4 **OREGON PERSONAL INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**
Thousands of Dollars - Not Seasonally Adjusted **December 2021**

	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
WITHHOLDING	2,059,715	2,223,410	2,183,444	1,997,661	8,464,230	2,127,124	2,291,161	2,321,603	2,266,779	9,006,667
%CHYA	6.9%	9.0%	5.0%	-0.1%	5.2%	3.3%	3.0%	6.3%	13.5%	6.4%
EST. PAYMENTS	413,316	296,072	376,127	428,769	1,514,284	497,544	292,601	432,742	701,877	1,924,764
%CHYA	12.4%	4.3%	16.9%	-19.4%	0.6%	20.4%	-1.2%	15.1%	63.7%	27.1%
FINAL PAYMENTS[1]	131,560	195,074	159,708	330,328	816,671	758,710	142,228	220,765	1,500,229	2,621,931
%CHYA	25.7%	24.6%	-29.2%	-76.2%	-56.4%	476.7%	-27.1%	38.2%	354.2%	221.1%
REFUNDS	144,251	289,464	1,120,326	735,922	2,289,962	432,836	360,529	558,588	672,421	2,024,375
%CHYA	2.5%	-13.8%	105.1%	65.2%	56.0%	200.1%	24.6%	-50.1%	-8.6%	-11.6%
OTHER	(222,477)	-	-	175,167	(47,310)	(175,167)	-	-	194,880	19,713
TOTAL	2,237,864	2,425,092	1,598,954	2,196,004	8,457,914	2,775,375	2,365,460	2,416,522	3,991,345	11,548,702
%CHYA	10.8%	13.1%	-23.2%	-40.5%	-14.9%	24.0%	-2.5%	51.1%	81.8%	36.5%
	2021:3	**2021:4**	**2022:1**	**2022:2**	**FY 2022**	**2022:3**	**2022:4**	**2023:1**	**2023:2**	**FY 2023**
WITHHOLDING	2,393,970	2,487,374	2,458,838	2,335,696	9,675,878	2,444,333	2,531,169	2,582,518	2,461,502	10,019,522
%CHYA	12.5%	8.6%	5.9%	3.0%	7.4%	2.1%	1.8%	5.0%	5.4%	3.6%
EST. PAYMENTS	486,859	314,543	365,410	701,432	1,868,245	351,636	279,366	368,732	752,694	1,752,429
%CHYA	-2.1%	7.5%	-15.6%	-0.1%	-2.9%	-27.8%	-11.2%	0.9%	7.3%	-6.2%
FINAL PAYMENTS[1]	148,649	205,133	189,422	877,187	1,420,391	100,949	146,619	199,554	1,152,568	1,599,690
%CHYA	-80.4%	44.2%	-14.2%	-41.5%	-45.8%	-32.1%	-28.5%	5.3%	31.4%	12.6%
REFUNDS	165,333	357,103	1,309,225	1,036,805	2,868,465	270,074	499,339	902,041	744,807	2,416,261
%CHYA	-61.8%	-1.0%	134.4%	54.2%	41.7%	63.4%	39.8%	-31.1%	-28.2%	-15.8%
OTHER	(194,880)	-	-	294,928	100,048	(294,928)	-	-	302,568	7,640
TOTAL	2,669,266	2,649,948	1,704,445	3,172,439	10,196,097	2,331,917	2,457,815	2,248,763	3,924,524	10,963,019
%CHYA	-3.8%	12.0%	-29.5%	-20.5%	-11.7%	-12.6%	-7.3%	31.9%	23.7%	7.5%
	2023:3	**2023:4**	**2024:1**	**2024:2**	**FY 2023**	**2024:3**	**2024:4**	**2025:1**	**2025:2**	**FY 2025**
WITHHOLDING	2,602,017	2,694,381	2,736,217	2,603,521	10,636,136	2,724,553	2,821,311	2,870,586	2,732,191	11,148,641
%CHYA	6.5%	6.4%	6.0%	5.8%	6.2%	4.7%	4.7%	4.9%	4.9%	4.8%
EST. PAYMENTS	377,334	299,783	394,898	796,325	1,868,340	399,207	317,160	416,997	830,976	1,964,340
%CHYA	7.3%	7.3%	7.1%	5.8%	6.6%	5.8%	5.8%	5.6%	4.4%	5.1%
FINAL PAYMENTS[1]	135,165	201,467	229,405	1,385,352	1,951,390	135,211	81,648	225,946	1,463,473	1,906,278
%CHYA	33.9%	37.4%	15.0%	20.2%	22.0%	0.0%	-59.5%	-1.5%	5.6%	-2.3%
REFUNDS	157,959	344,812	881,605	689,268	2,073,644	306,117	472,852	964,162	794,081	2,537,213
%CHYA	-41.5%	-30.9%	-2.3%	-7.5%	-14.2%	93.8%	37.1%	9.4%	15.2%	22.4%
OTHER	(302,568)	-	-	339,845	37,278	(339,845)	-	-	328,127	(11,718)
TOTAL	2,653,989	2,850,819	2,478,914	4,435,776	12,419,499	2,613,009	2,747,266	2,549,368	4,560,686	12,470,328
%CHYA	13.8%	16.0%	10.2%	13.0%	13.3%	-1.5%	-3.6%	2.8%	2.8%	0.4%
	2025:3	**2025:4**	**2026:1**	**2026:2**	**FY 2026**	**2026:3**	**2026:4**	**2027:1**	**2027:2**	**FY 2027**
WITHHOLDING	2,859,193	2,960,726	3,005,322	2,859,392	11,684,633	2,992,321	3,098,589	3,168,120	3,017,627	12,276,658
%CHYA	4.9%	4.9%	4.7%	4.7%	4.8%	4.7%	4.7%	5.4%	5.5%	5.1%
EST. PAYMENTS	416,578	330,961	434,286	854,677	2,036,502	428,460	340,400	448,664	908,028	2,125,553
%CHYA	4.4%	4.4%	4.1%	2.9%	3.7%	2.9%	2.9%	3.3%	6.2%	4.4%
FINAL PAYMENTS[1]	146,709	228,134	249,975	1,526,800	2,151,619	160,480	243,054	255,498	1,514,606	2,173,638
%CHYA	8.5%	179.4%	10.6%	4.3%	12.9%	9.4%	6.5%	2.2%	-0.8%	1.0%
REFUNDS	181,872	377,701	1,001,194	790,400	2,351,168	182,569	397,992	1,070,110	844,915	2,495,586
%CHYA	-40.6%	-20.1%	3.8%	-0.5%	-7.3%	0.4%	5.4%	6.9%	6.9%	6.1%
OTHER	(328,127)	-	-	274,737	(53,390)	(274,737)	-	-	290,626	15,889
TOTAL	2,912,481	3,142,119	2,688,389	4,725,206	13,468,195	3,123,955	3,284,052	2,802,172	4,885,973	14,096,151
%CHYA	11.5%	14.4%	5.5%	3.6%	8.0%	7.3%	4.5%	4.2%	3.4%	4.7%
	2027:3	**2027:4**	**2028:1**	**2028:2**	**FY 2028**	**2028:3**	**2028:4**	**2029:1**	**2029:2**	**FY 2028**
WITHHOLDING	3,157,865	3,269,987	3,346,303	3,187,762	12,961,916	3,335,900	3,454,340	3,544,347	3,377,782	13,712,370
%CHYA	5.5%	5.5%	5.6%	5.6%	5.6%	5.6%	5.6%	5.9%	6.0%	5.8%
EST. PAYMENTS	455,205	361,649	476,990	969,345	2,263,189	485,944	386,070	509,177	1,034,482	2,415,674
%CHYA	6.2%	6.2%	6.3%	6.8%	6.5%	6.8%	6.8%	6.7%	6.7%	6.7%
FINAL PAYMENTS1	164,129	245,900	267,522	1,613,124	2,290,675	176,124	262,298	286,257	1,738,521	2,463,200
%CHYA	2.3%	1.2%	4.7%	6.5%	5.4%	7.3%	6.7%	7.0%	7.8%	7.5%
REFUNDS	194,855	425,174	1,093,693	862,363	2,576,086	199,534	434,328	1,118,520	882,102	2,634,483
%CHYA	6.7%	6.8%	2.2%	2.1%	3.2%	2.4%	2.2%	2.3%	2.3%	2.3%
OTHER	(290,626)	-	-	379,908	89,282	(379,908)	-	-	387,066	7,158
TOTAL	3,291,718	3,452,362	2,997,122	5,287,775	15,028,976	3,418,527	3,668,381	3,221,261	5,655,749	15,963,917
%CHYA	5.4%	5.1%	7.0%	8.2%	6.6%	3.9%	6.3%	7.5%	7.0%	6.2%
	2029:3	**2029:4**	**2030:1**	**2030:2**	**FY 2030**	**2030:3**	**2030:4**	**2031:1**	**2031:2**	**FY 2030**
WITHHOLDING	3,534,732	3,660,220	3,754,723	3,578,142	14,527,818	3,744,403	3,877,336	3,970,587	3,782,863	15,375,189
%CHYA	6.0%	6.0%	5.9%	5.9%	5.9%	5.9%	5.9%	5.7%	5.7%	5.8%
EST. PAYMENTS	518,598	412,013	543,021	1,098,592	2,572,225	550,737	437,547	576,852	1,169,261	2,734,397
%CHYA	6.7%	6.7%	6.6%	6.2%	6.5%	6.2%	6.2%	6.2%	6.4%	6.3%
FINAL PAYMENTS1	186,822	279,715	304,631	1,866,998	2,638,166	198,452	298,536	326,784	2,001,767	2,825,539
%CHYA	6.1%	6.6%	6.4%	7.4%	7.1%	6.2%	6.7%	7.3%	7.2%	7.1%
REFUNDS	204,510	444,690	1,160,837	915,933	2,725,970	212,299	461,798	1,227,698	969,157	2,870,950
%CHYA	2.5%	2.4%	3.8%	3.8%	3.5%	3.8%	3.8%	5.8%	5.8%	5.3%
OTHER	(387,066)	-	-	445,917	89,282	(445,917)	-	-	436,423	-
TOTAL	3,648,577	3,907,258	3,441,538	6,073,716	17,101,520	3,835,377	4,151,622	3,646,525	6,421,157	18,064,176
%CHYA	6.7%	6.5%	6.8%	7.4%	7.1%	5.1%	6.3%	6.0%	5.7%	5.6%

Note: "Other" includes July withholding accrued to June. Tax law impacts are reflected in the collections numbers to produce more meaningful projections.

Table B.5 Oregon Corporate Income Tax Revenue Forecast

TABLE B.5 **OREGON CORPORATE INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted **December 2021**

	2009:3	2009:4	2010:1	2010:2	FY 2010	2010:3	2010:4	2011:1	2011:2	FY 2011
ADVANCE PAYMENTS	79,579	163,877	66,451	147,313	457,220	115,286	175,561	76,405	165,354	532,606
%CHYA	-20.9%	12.8%	4.2%	51.3%	12.3%	44.9%	7.1%	15.0%	12.2%	16.5%
FINAL PAYMENTS	20,404	24,009	38,412	45,714	128,539	21,781	21,206	35,770	40,805	119,562
%CHYA	-13.2%	-10.2%	72.1%	109.5%	36.2%	6.8%	-11.7%	-6.9%	-10.7%	-7.0%
REFUNDS	29,072	137,244	40,080	25,774	232,170	23,130	89,877	39,065	31,489	183,562
%CHYA	3.3%	9.9%	-40.6%	-30.7%	-9.9%	-20.4%	-34.5%	-2.5%	22.2%	-20.9%
TOTAL	70,910	50,642	64,784	167,254	353,589	113,936	106,890	73,111	174,670	468,606
%CHYA	-26.1%	7.3%	247.5%	104.0%	45.1%	60.7%	111.1%	12.9%	4.4%	32.5%

	2011:3	2011:4	2012:1	2012:2	FY 2012	2012:3	2012:4	2013:1	2013:2	FY 2013
ADVANCE PAYMENTS	120,766	154,290	86,873	156,652	518,581	130,348	110,207	80,942	282,526	604,023
%CHYA	4.8%	-12.1%	13.7%	-5.3%	-2.6%	7.9%	-28.6%	-6.8%	80.4%	16.5%
FINAL PAYMENTS	19,117	26,841	32,512	33,322	111,792	16,387	21,377	36,660	34,009	108,433
%CHYA	-12.2%	26.6%	-9.1%	-18.3%	-6.5%	-14.3%	-20.4%	12.8%	2.1%	-3.0%
REFUNDS	34,927	91,252	55,051	18,153	199,384	33,212	17,832	25,595	182,929	259,568
%CHYA	51.0%	1.5%	40.9%	-42.4%	8.6%	-4.9%	-80.5%	-53.5%	907.7%	30.2%
TOTAL	104,955	89,878	64,335	171,820	430,989	113,524	113,751	92,007	133,606	452,888
%CHYA	-7.9%	-15.9%	-12.0%	-1.6%	-8.0%	8.2%	26.6%	43.0%	-22.2%	5.1%

	2013:3	2013:4	2014:1	2014:2	FY 2014	2014:3	2014:4	2015:1	2015:2	FY 2015
ADVANCE PAYMENTS	123,591	187,195	150,401	183,348	644,535	193,248	206,088	106,689	183,611	689,637
%CHYA	-5.2%	69.9%	85.8%	-35.1%	6.7%	56.4%	10.1%	-29.1%	0.1%	7.0%
FINAL PAYMENTS	27,794	18,162	32,218	52,283	130,456	28,815	73,552	57,268	71,415	231,051
%CHYA	69.6%	-15.0%	-12.1%	53.7%	20.3%	3.7%	305.0%	77.8%	36.6%	77.1%
REFUNDS	20,123	118,303	109,296	32,511	280,232	49,952	155,439	58,361	35,167	298,918
%CHYA	-39.4%	563.4%	327.0%	-82.2%	8.0%	148.2%	31.4%	-46.6%	8.2%	6.7%
TOTAL	131,262	87,054	73,323	203,120	494,759	172,111	124,202	105,597	219,860	621,770
%CHYA	15.6%	-23.5%	-20.3%	52.0%	9.2%	31.1%	42.7%	44.0%	8.2%	25.7%

	2015:3	2015:4	2016:1	2016:2	FY 2016	2016:3	2016:4	2017:1	2017:2	FY 2017
ADVANCE PAYMENTS	173,329	220,326	118,673	202,813	715,141	136,698	215,677	102,663	195,412	650,449
%CHYA	-10.3%	6.9%	11.2%	10.5%	3.7%	-21.1%	-2.1%	-13.5%	-3.6%	-9.0%
FINAL PAYMENTS	67,305	59,752	63,509	70,433	260,998	44,746	93,441	52,164	81,824	272,175
%CHYA	133.6%	-18.8%	10.9%	-1.4%	13.0%	-33.5%	56.4%	-17.9%	16.2%	4.3%
REFUNDS	42,388	156,984	85,446	81,453	366,271	39,680	166,537	73,066	57,733	337,016
%CHYA	-15.1%	1.0%	46.4%	131.6%	22.5%	-6.4%	6.1%	-14.5%	-29.1%	-8.0%
TOTAL	198,245	123,094	96,736	191,793	609,868	141,764	142,581	81,761	219,503	585,608
%CHYA	15.2%	-0.9%	-8.4%	-12.8%	-1.9%	-28.5%	15.8%	-15.5%	14.4%	-4.0%

	2017:3	2017:4	2018:1	2018:2	FY 2018	2018:3	2018:4	2019:1	2019:2	FY 2019
ADVANCE PAYMENTS	179,603	185,787	182,395	303,835	851,620	222,891	249,768	158,748	264,445	895,852
%CHYA	31.4%	-13.9%	77.7%	55.5%	30.9%	24.1%	34.4%	-13.0%	-13.0%	5.2%
FINAL PAYMENTS	42,600	66,460	46,270	108,539	263,869	74,735	102,942	68,818	174,861	421,356
%CHYA	-4.8%	-28.9%	-11.3%	32.6%	-3.1%	75.4%	54.9%	48.7%	61.1%	59.7%
REFUNDS	72,225	129,963	122,291	54,224	378,703	43,428	167,871	128,586	50,616	390,501
%CHYA	82.0%	-22.0%	67.4%	-6.1%	12.4%	-39.9%	29.2%	5.1%	-6.7%	3.1%
TOTAL	149,978	122,284	106,374	358,150	736,786	254,198	184,839	98,980	388,690	926,707
%CHYA	5.8%	-14.2%	30.1%	63.2%	25.8%	69.5%	51.2%	-7.0%	8.5%	25.8%

TABLE B.5 **OREGON CORPORATE INCOME TAX REVENUE FORECAST - QUARTERLY COLLECTIONS**

Thousands of Dollars - Not Seasonally Adjusted **December 2021**

	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
ADVANCE PAYMENTS	236,341	346,651	137,782	263,138	983,912	260,668	378,192	249,855	381,413	1,270,128
%CHYA	6.0%	38.8%	-13.2%	-0.5%	9.8%	10.3%	9.1%	81.3%	44.9%	29.1%
FINAL PAYMENTS	67,657	105,446	66,346	111,149	350,598	114,684	98,371	78,356	263,524	554,935
%CHYA	-9.5%	2.4%	-3.6%	-36.4%	-16.8%	69.5%	-6.7%	18.1%	137.1%	58.3%
REFUNDS	73,866	247,403	91,312	86,858	499,439	62,538	254,020	154,026	153,392	623,976
%CHYA	70.1%	47.4%	-29.0%	71.6%	27.9%	-15.3%	2.7%	68.7%	76.6%	24.9%
TOTAL	230,132	204,694	112,816	287,429	835,071	312,814	222,543	174,185	491,545	1,201,087
%CHYA	-9.5%	10.7%	14.0%	-26.1%	-9.9%	35.9%	8.7%	54.4%	71.0%	43.8%

	2021:3	2021:4	2022:1	2022:2	FY 2022	2022:3	2022:4	2023:1	2023:2	FY 2023
ADVANCE PAYMENTS	325,648	335,511	174,277	255,017	1,090,452	209,607	256,777	141,647	218,734	826,765
%CHYA	24.9%	-11.3%	-30.2%	-33.1%	-14.1%	-35.6%	-23.5%	-18.7%	-14.2%	-24.2%
FINAL PAYMENTS	58,369	129,153	79,908	153,637	421,067	41,968	172,223	89,844	127,190	431,225
%CHYA	-49.1%	31.3%	2.0%	-41.7%	-24.1%	-28.1%	33.3%	12.4%	-17.2%	2.4%
REFUNDS	49,987	286,030	152,722	84,316	573,055	67,194	286,696	155,396	92,942	602,229
%CHYA	-20.1%	12.6%	-0.8%	-45.0%	-8.2%	34.4%	0.2%	1.8%	10.2%	5.1%
TOTAL	334,029	178,634	101,464	324,337	938,464	184,380	142,304	76,095	252,982	655,761
%CHYA	6.8%	-19.7%	-41.7%	-34.0%	-21.9%	-44.8%	-20.3%	-25.0%	-22.0%	-30.1%

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
ADVANCE PAYMENTS	190,695	243,118	138,544	220,385	792,742	191,492	246,621	143,191	228,829	810,132
%CHYA	-9.0%	-5.3%	-2.2%	0.8%	-4.1%	0.4%	1.4%	3.4%	3.8%	2.2%
FINAL PAYMENTS	100,154	239,740	171,955	209,828	721,677	120,851	295,910	201,345	247,553	865,659
%CHYA	138.6%	39.2%	91.4%	65.0%	67.4%	20.7%	23.4%	17.1%	18.0%	20.0%
REFUNDS	88,716	315,834	203,825	131,628	740,003	103,528	368,582	228,678	147,580	848,368
%CHYA	32.0%	10.2%	31.2%	41.6%	22.9%	16.7%	16.7%	12.2%	12.1%	14.6%
TOTAL	202,132	167,024	106,673	298,586	774,415	208,815	173,949	115,858	328,801	827,423
%CHYA	9.6%	17.4%	40.2%	18.0%	18.1%	3.3%	4.1%	8.6%	10.1%	6.8%

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
ADVANCE PAYMENTS	200,655	258,894	150,305	240,201	850,054	209,337	270,121	156,755	250,461	886,674
%CHYA	4.8%	5.0%	5.0%	5.0%	4.9%	4.3%	4.3%	4.3%	4.3%	4.3%
FINAL PAYMENTS	147,918	348,416	212,042	275,096	983,472	164,471	362,952	221,840	302,849	1,052,112
%CHYA	22.4%	17.7%	5.3%	11.1%	13.6%	11.2%	4.2%	4.6%	10.1%	7.0%
REFUNDS	115,324	410,569	232,512	150,037	908,442	117,953	419,870	237,771	153,423	929,016
%CHYA	11.4%	11.4%	1.7%	1.7%	7.1%	2.3%	2.3%	2.3%	2.3%	2.3%
TOTAL	233,249	196,740	129,835	365,260	925,084	255,856	213,203	140,825	399,886	1,009,769
%CHYA	11.7%	13.1%	12.1%	11.1%	11.8%	9.7%	8.4%	8.5%	9.5%	9.2%

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
ADVANCE PAYMENTS	215,280	277,740	159,339	254,668	907,027	222,429	287,007	163,855	261,963	935,254
%CHYA	2.8%	2.8%	1.6%	1.7%	2.3%	3.3%	3.3%	2.8%	2.9%	3.1%
FINAL PAYMENTS	179,708	373,294	226,383	321,862	1,101,247	195,222	386,506	233,790	342,754	1,158,272
%CHYA	9.3%	2.8%	2.0%	6.3%	4.7%	8.6%	3.5%	3.3%	6.5%	5.2%
REFUNDS	122,266	435,238	244,712	157,949	960,165	123,935	441,259	248,124	160,174	973,492
%CHYA	3.7%	3.7%	2.9%	2.9%	3.4%	1.4%	1.4%	1.4%	1.4%	1.4%
TOTAL	272,722	215,796	141,010	418,581	1,048,110	293,715	232,255	149,521	444,542	1,120,033
%CHYA	6.6%	1.2%	0.1%	4.7%	3.8%	7.7%	7.6%	6.0%	6.2%	6.9%

	2029:3	2029:4	2030:1	2030:2	FY 2030	2030:3	2030:4	2031:1	2031:2	FY 2031
ADVANCE PAYMENTS	229,546	296,243	169,053	270,190	965,032	236,688	305,296	174,172	278,289	994,445
%CHYA	3.2%	3.2%	3.2%	3.1%	3.2%	3.1%	3.1%	3.0%	3.0%	3.0%
FINAL PAYMENTS	209,512	400,109	242,502	366,030	1,218,153	224,423	413,909	251,367	389,579	1,279,277
%CHYA	7.3%	3.5%	3.7%	6.8%	5.2%	7.1%	3.4%	3.7%	6.4%	5.0%
REFUNDS	124,977	445,023	250,174	161,468	981,642	127,004	452,087	254,145	164,024	997,260
%CHYA	0.8%	0.9%	0.8%	0.8%	0.8%	1.6%	1.6%	1.6%	1.6%	1.6%
TOTAL	314,081	251,330	161,381	474,752	1,201,544	334,106	267,119	171,393	503,843	1,276,461
%CHYA	6.9%	8.2%	7.9%	6.8%	7.3%	6.4%	6.3%	6.2%	6.1%	6.2%

Table B.6 Cigarette and Tobacco Tax Distribution

TABLE B.6 — December 2021

Cigarette & Tobacco Tax Distribution (Millions of $)

	Cigarette Tax Distribution*								Other Tobacco Tax Distribution				Inhalent Delivery Distribution		
						Tobacco Use Reduction[2]									
	Total	General Fund	Health Plan	Mental Health	Health Authority[1]	Old	New	Cities, Counties & Public Transit	Total	General Fund	Health Plan	Tobacco Use Reduction	Total	Health Authority	Tobacco Use Reduction
Distribution Forecast															
2019-20	187.2	30.5	121.0	21.2	0.0	4.8	0.0	9.7	57.7	30.9	24.1	2.7	0.0	0.0	0.0
2020-21	292.3	24.6	107.1	18.7	118.9	4.3	10.1	8.5	56.6	30.4	23.6	2.6	10.5	9.5	1.1
2019-21 Biennium	479.5	55.1	228.1	39.9	118.9	9.1	10.1	18.2	114.3	61.3	47.7	5.3	10.5	9.5	1.1
2021-22	348.9	22.9	89.4	15.6	189.4	3.6	20.8	7.1	60.6	32.6	25.2	2.8	15.7	14.2	1.6
2022-23	336.1	22.2	86.5	15.1	181.7	3.5	20.2	6.9	60.7	32.7	25.2	2.8	9.9	8.9	1.0
2021-23 Biennium	684.9	45.1	175.9	30.8	371.0	7.0	41.0	14.0	121.3	65.3	50.4	5.6	25.6	23.1	2.6
2023-24	333.1	22.0	85.8	15.0	180.1	3.4	20.0	6.8	60.8	32.7	25.2	2.8	10.2	9.1	1.0
2024-25	325.3	21.5	83.8	14.7	175.8	3.3	19.5	6.7	61.2	32.9	25.4	2.8	10.3	9.2	1.0
2023-25 Biennium	658.4	43.5	169.5	29.7	355.9	6.8	39.5	13.5	121.9	65.6	50.6	5.6	20.4	18.4	2.0
2025-26	315.9	20.9	81.3	14.2	170.7	3.2	19.0	6.5	61.2	32.9	25.4	2.8	10.3	9.3	1.0
2026-27	309.8	20.5	79.8	14.0	167.5	3.2	18.6	6.4	61.5	33.1	25.5	2.8	10.4	9.4	1.0
2025-27 Biennium	625.7	41.3	161.1	28.2	338.2	6.4	37.6	12.9	122.7	66.0	51.0	5.7	20.8	18.7	2.1
2027-28	304.5	20.1	78.4	13.7	164.6	3.1	18.3	6.3	61.4	33.1	25.5	2.8	10.5	9.5	1.1
2028-29	299.8	19.8	77.2	13.5	162.1	3.1	18.0	6.2	61.3	33.0	25.5	2.8	10.6	9.5	1.1
2027-29 Biennium	604.3	39.9	155.6	27.2	326.7	6.2	36.3	12.4	122.7	66.1	51.0	5.7	21.1	19.0	2.1
2029-30	295.2	19.5	76.0	13.3	159.6	3.0	17.7	6.1	61.2	32.9	25.4	2.8	10.7	9.6	1.1
2030-31	290.6	19.2	74.8	13.1	157.1	3.0	17.5	6.0	61.0	32.9	25.4	2.8	10.8	9.7	1.1
2029-31 Biennium	585.8	38.7	150.8	26.4	316.7	6.0	35.2	12.0	122.2	65.8	50.8	5.6	21.4	19.3	2.1

[1] Includes the cigarette floor tax in FY21 of $27.7 million and FY22 of $1.6 million

[2] Old and New refere to pre- and post-Measure 108 (2020) taxes and programs

Table B.7 Revenue Distribution to Local Governments

TABLE B.7 **December 2021**

Liquor Apportionment and Revenue Distribution to Local Governments (Millions of $)

	Liquor Apportionment Distribution								
					City Revenue				
	Total Liquor Revenue Available	General Fund (56%)	Mental Health[1]	Oregon Wine Board	Revenue Sharing	Regular	Total	Counties	Cigarette Tax Distribution[2]
2019-20	290.649	165.629	9.534	0.338	52.340	36.638	88.979	26.170	9.653
2020-21	314.814	179.338	10.123	0.359	56.815	39.771	96.586	28.408	8.546
2019-21 Biennium	605.463	344.967	19.657	0.697	109.155	76.409	185.564	54.578	18.199
2021-22	295.864	168.764	9.887	0.363	53.114	37.180	90.294	26.557	7.130
2022-23	311.535	177.703	10.410	0.382	55.927	39.149	95.076	27.964	6.903
2021-23 Biennium	607.399	346.467	20.297	0.745	109.041	76.329	185.370	54.521	14.033
2023-24	309.147	168.162	10.633	0.384	59.078	41.353	100.431	29.537	6.843
2024-25	323.442	176.334	10.856	0.395	61.754	43.227	104.981	30.875	6.681
2023-25 Biennium	632.589	344.497	21.489	0.779	120.832	84.580	205.412	60.412	13.524
2025-26	338.695	185.051	11.100	0.407	64.610	45.225	109.835	32.303	6.488
2026-27	354.720	194.204	11.363	0.420	67.608	47.324	114.932	33.801	6.364
2025-27 Biennium	693.414	379.254	22.462	0.828	132.217	92.549	224.766	66.104	12.852
2027-28	371.349	203.701	11.636	0.434	70.719	49.502	120.220	35.357	6.255
2028-29	388.504	213.502	11.914	0.448	73.929	51.749	125.677	36.962	6.158
2027-29 Biennium	759.853	417.203	23.550	0.883	144.647	101.250	245.898	72.319	12.413
2029-30	406.459	223.774	12.200	0.463	77.285	54.098	131.382	38.640	6.063
2030-31	425.250	234.540	12.492	0.478	80.793	56.553	137.346	40.394	5.970
2029-31 Biennium	831.708	458.314	24.692	0.941	158.078	110.651	268.729	79.033	12.033

[1] Mental Health Alcoholism and Drug Services Account, per ORS 471.810

[2] For details on cigarette revenues see TABLE B.6 on previous page

Table B.8 Track Record for the May 2021 Forecast

Table B.8 Track Record for the September 2021 Forecast

(Quarter ending September 30, 2021)

Personal Income Tax

	Forecast Comparison			Year/Year Change	
(Millions of dollars)	Actual Revenues**	Latest Forecast	Percent Difference	Prior Year	Percent Change
Withholding	$2,394.0	$2,285.4	4.7%	$2,127.1	12.5%
Dollar difference		$108.5		$131.0	
Estimated Payments*	$486.9	$440.5	10.5%	$497.5	-2.1%
Dollar difference		$46.3		$131.8	
Final Payments*	$148.6	$149.5	-0.6%	$758.7	-80.4%
Dollar difference		-$0.9		$25.5	
Refunds	-$165.3	-$231.8	-28.7%	-$432.8	-61.8%
Dollar difference		$66.5		$267.5	
Total Personal Income Tax	**$2,864.1**	**$2,643.7**	**8.3%**	**$2,950.5**	**-2.9%**
Dollar difference		$220.4		-$86.4	

Corporate Income Tax

	Forecast Comparison			Year/Year Change	
(Millions of dollars)	Actual Revenues**	Latest Forecast	Percent Difference	Prior Year	Percent Change
Advanced Payments	$325.6	$249.4	30.6%	$260.7	24.9%
Dollar difference		$76.2		$65.0	
Final Payments	$58.4	$108.2	-46.1%	$114.7	-49.1%
Dollar difference		-$49.8		-$56.3	
Refunds	-$50.0	-$76.0	-34.2%	-$62.5	-20.1%
Dollar difference		$26.0		$12.6	
Total Corporate Income Tax	**$334.0**	**$281.7**	**18.6%**	**$312.8**	**6.8%**
Dollar difference		$52.4		$21.2	

Total Income Tax

	Forecast Comparison			Year/Year Change	
(Millions of dollars)	Actual Revenues**	Latest Forecast	Percent Difference	Prior Year	Percent Change
Corporate and Personal Tax	**$3,198.2**	**$2,925.4**	**9.3%**	**$3,263.4**	**-2.0%**
Dollar difference		$272.8		-$65.2	

* Data separating estimated and other personal income tax payments is no longer available. Tracking represents estimates based on banking data.

** The September monthly financial statement was not available at time of publication. September revenues have been estimated.

Table B.9 Summary of Lottery Resources

TABLE B.9
Summary of Lottery Resources

Dec 2021 Forecast

(in millions of dollars)	2021-23 Current Forecast	2021-23 *Change from Sep-21*	2021-23 *Change from COS 2021*	2023-25 Current Forecast	2023-25 *Change from Sep-21*	2025-2027 Current Forecast	2025-2027 *Change from Sep-21*	2027-29 Current Forecast	2027-29 *Change from Sep-21*	2029-31 Current Forecast	2029-31 *Change from Sep-21*
LOTTERY EARNINGS											
Traditional Lottery	160.177	*2.174*	*1.342*	157.937	*0.756*	157.413	0.960	157.970	1.107	158.058	1.102
Video Lottery	1,539.690	*20.267*	*66.402*	1,585.938	*7.813*	1,719.342	7.002	1,864.012	7.375	1,995.986	7.897
Scoreboard (Sports Betting)[1]	22.538	*0.000*	*3.201*	35.952	*0.000*	41.763	0.000	44.911	0.000	48.296	0.000
Administrative Actions	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	0.000
Total Available to Transfer	1,722.405	*22.440*	*70.945*	1,779.826	*8.569*	1,918.519	7.962	2,066.893	8.482	2,202.341	8.999
ECONOMIC DEVELOPMENT FUND											
Beginning Balance	72.370	*0.000*	*0.000*	76.469	*14.698*	0.000	0.000	0.000	0.000	0.000	0.000
Transfers from Lottery	1,722.405	*22.440*	*70.945*	1,779.826	*8.569*	1,918.519	7.962	2,066.893	8.482	2,202.341	8.999
Other Resources[2]	2.000	*0.000*	*0.000*	2.000	*0.000*	2.000	0.000	2.000	0.000	2.000	0.000
Total Available Resources	1,796.775	*22.440*	*70.945*	1,858.295	*23.267*	1,920.519	7.962	2,068.893	8.482	2,204.341	8.999
ALLOCATION OF RESOURCES											
Constitutional Distributions											
Education Stability Fund[3]	310.033	*4.039*	*12.770*	320.108	1.542	255.681	1.056	183.063	46.844	194.916	49.864
Oregon Capital Matching Fund[3]	0.000	*0.000*	*0.000*	0.000	0.000	74.631	0.315	157.414	(37.764)	167.606	(40.204)
Parks and Natural Resources Fund[4]	258.361	*3.366*	*10.642*	266.974	1.285	287.778	1.194	310.034	1.272	330.351	1.350
Veterans' Services Fund[5]	25.836	*0.337*	*1.064*	26.697	0.129	28.778	0.119	31.003	0.127	33.035	0.135
Other Distributions											
Outdoor School Education Fund[6]	49.419	*0.000*	*0.000*	51.222	0.000	53.394	0.000	55.658	0.000	58.019	0.000
County Economic Development	54.210	*0.000*	*0.000*	60.805	0.300	65.920	0.268	71.466	0.283	76.526	0.303
HECC Collegiate Athletic & Scholarships[7]	16.515	*0.000*	*0.000*	17.798	0.086	19.185	0.080	20.669	0.085	22.023	0.090
Gambling Addiction [7]	16.515	*0.000*	*0.000*	17.798	0.086	19.185	0.080	20.669	0.085	22.023	0.090
County Fairs	3.828	*0.000*	*0.000*	3.828	0.000	3.828	0.000	3.828	0.000	3.828	0.000
Other Legislatively Adopted Allocations[8]	972.925	*0.000*	*0.000*	234.300	0.000	234.300	0.000	234.300	0.000	234.300	0.000
Employer Incentive Fund (PERS)[1]	12.666	*0.000*	*0.000*	23.554	(0.000)	27.682	0.000	30.103	(0.168)	32.377	(0.180)
Total Distributions	1,720.306	*7.742*	*24.476*	1,023.084	3.427	1,070.362	3.112	1,118.207	10.764	1,175.004	11.447
Ending Balance/Discretionary Resources	76.469	*14.698*	*46.469*	835.211	19.840	850.157	4.850	950.686	(2.282)	1,029.336	(2.449)

Note: Some totals may not foot due to rounding.

1. Sports Betting revenues are transferred to Economic Development Fund making them subject to the constitutional distributions, after which the remainder is transferred to the Employer Incentive Fund
2. Includes reversions (unspent allocations from previous biennium) and interest earnings on Economic Development Fund.
3. Eighteen percent of proceeds accrue to the Ed. Stability Fund, until the balance equals 5% of GF Revenues. Thereafter, 15% of proceeds accrue to the School Capital Matching Fund.
4. The Parks and Natural Resources Fund Constitutional amendment requires 15% of net proceeds be transferred to this fund.
5. Per Ballot Measure 96 (2016), 1.5% of net lottery proceeds are dedicated to the Veterans' Services Fund
6. Per Ballot Measure 99 (2016), the lesser of 4% of Lottery transfers or $22 million per year is transferred to the Outdoor Education Account. Adjusted annually for inflation.
7. Approximately one percent of net lottery proceeds are dedicated to each program. Certain limits are imposed by the Legislature.
8. Includes Debt Service Allocations, Allocations to State School Fund and Other Agency Allocations

Table B.10 Budgetary Reserve Summary and Outlook

Table B.10: Budgetary Reserve Summary and Outlook **Dec 2021**

Rainy Day Fund

(Millions)	2019-21	2021-23	2023-25	2025-27	2027-29
Beginning Balance	$666.6	$962.2	$1,265.1	$1,625.7	$2,088.6
Interest Earnings	$22.8	$13.3	$39.5	$89.9	$129.8
Deposits[1]	$272.8	$289.5	$321.1	$373.0	$396.6
Triggered Withdrawals	$0.0	$0.0	$0.0	$0.0	$0.0
Ending Balance[2]	**$962.2**	**$1,265.0**	**$1,625.7**	**$2,088.6**	**$2,614.9**

Education Stability Fund[3]

(Millions)	2019-21	2021-23	2023-25	2025-27	2027-29
Beginning Balance	$621.1	$414.6	$693.4	$981.5	$1,211.6
Interest Earnings[4]	$20.1	$6.9	$23.7	$56.6	$76.4
Deposits[5]	$194.7	$279.0	$288.1	$230.1	$164.8
Distributions	$419.9	$7.1	$23.7	$56.6	$76.4
Oregon Education Fund	$0.0	$0.0	$0.0	$0.0	$0.0
Oregon Opportunity Grant	$19.9	$7.1	$23.7	$56.6	$76.4
Withdrawals	$400.0	$0.0	$0.0	$0.0	$0.0
Ending Balance	**$414.6**	**$693.4**	**$981.5**	**$1,211.6**	**$1,376.3**

Total Reserves

(Millions)	2019-21	2021-23	2023-25	2025-27	2027-29
Ending Balances	**$1,376.8**	**$1,958.4**	**$2,607.1**	**$3,300.2**	**$3,991.3**
Percent of General Fund Revenues	5.8%	8.2%	9.4%	10.7%	11.5%

Footnotes:
1. Includes transfer of ending General Fund balances up to 1% of budgeted appropriations as well as private donations. Assumes future appropriations equal to 98.75 percent of available resources. Includes forecast for corporate income taxes above rate of 6.6% for the biennium are deposited on or before Jun 30 of each odd-numbered year.
2. Available funds in a given biennium equal 2/3rds of the beginning balance under current law.
3. Excludes funds in the Oregon Growth and the Oregon Resource and Technology Development subaccounts.
4. Interest earnings are distributed to the Oregon Education Funds (75%) and the State Scholarship Fund (25%), provided there remains debt outstanding. In the event that debt is paid off, all interest earnings distributed to the State Scholarship Fund.
5. Contributions to the ESF are capped at 5% of the prior biennium's General Fund revenue total. Quarterly contributions are made until the balance exceeds the cap.

Table B.11 Recreational Marijuana Resources and Distributions

TABLE B.11
Summary of Marijuana Resources
Dec 2021

(in millions of dollars)	2021-23 Current Forecast	2021-23 Change from Sep-21	2021-23 Change from COS 2021	2023-25 Current Forecast	2023-25 Change from Sep-21	2025-27 Current Forecast	2025-27 Change from Sep-21	2027-29 Current Forecast	2027-29 Change from Sep-21	2029-31 Current Forecast	2029-31 Change from Sep-21
MARIJUANA EARNINGS											
+ Tax Revenue [1]	355.461	*3.058*	*1.074*	377.204	*0.000*	417.310	0.000	462.371	0.000	512.390	NA
+ Medical Marijuana Tax Revenue [2]	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	0.000	31.896	0.000	44.041	NA
- Administrative Costs [3]	15.026	*0.000*	*0.000*	15.374	*0.000*	15.746	0.000	16.144	0.000	16.571	NA
Net Available to Transfer	340.434	*3.058*	*1.074*	361.830	*0.000*	401.564	*0.000*	446.227	*0.000*	495.819	*NA*
OREGON MARIJUANA ACCOUNT											
Beginning Balance	0.000	*0.000*	*(0.000)*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	NA
Revenue Transfers	340.434	*3.058*	*1.074*	361.830	*0.000*	401.564	0.000	478.123	0.000	539.860	NA
Other Resources	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	NA
Total Available Resources	340.434	*3.058*	*1.074*	361.830	*0.000*	401.564	*0.000*	478.123	*0.000*	539.860	*NA*
ALLOCATION OF RESOURCES [4]											
Drug Treatment & Recovery	250.434	*3.058*	*1.074*	271.830	*0.000*	311.564	0.000	388.123	0.000	449.860	NA
State School Fund	36.000	*0.000*	*0.000*	36.000	*0.000*	36.000	0.000	36.000	0.000	36.000	NA
Mental Health, Alcoholism, & Drug Services	18.000	*0.000*	*0.000*	18.000	*0.000*	18.000	0.000	18.000	0.000	18.000	NA
State Police	13.500	*0.000*	*0.000*	13.500	*0.000*	13.500	0.000	13.500	0.000	13.500	NA
Cities	9.000	*0.000*	*0.000*	9.000	*0.000*	9.000	0.000	9.000	0.000	9.000	NA
Counties	9.000	*0.000*	*0.000*	9.000	*0.000*	9.000	0.000	9.000	0.000	9.000	NA
Alcohol & Drug Abuse Prevention, Intervention & Treatment	4.500	*0.000*	*0.000*	4.500	*0.000*	4.500	0.000	4.500	0.000	4.500	NA
Total Distributions	340.434	*3.058*	*1.074*	361.830	*0.000*	401.564	*0.000*	478.123	*0.000*	539.860	*NA*
Ending Balance	0.000	*0.000*	*0.000*	0.000	*0.000*	0.000	0.000	0.000	0.000	0.000	NA

Note: Some totals may not foot due to rounding.

1. Retailers pay taxes monthly, however taxes are not available for distribution to recepient programs until the Department of Revenue receives and processes retailers' quarterly tax returns. As such, there is a one to two quarter lag between when the initial monthly payments are made and when monies be come available to distribute.

2. Medical marijuana being exempt from tax is an explicit tax expenditure per HB 2433 (2021). Tax expenditures sunset after 6 years, although they may be renewed at that time. Current law is that medical marijuana sales will be taxed beginning January 1, 2028.

3. Administrative Costs reflect monthly collection costs for the Department of Revenue in addition to distributions to the Criminal Justice Commission and OLCC per SB 1544 (2018)

4. Per Measure 110 (2020), the first $11.25 million per quarter ($45m per year) is distributed via forumula to the initial recipient programs. All revenues above $11.25 million go to the Drug Treatment & Recovery Fund.

Table B.12 Fund for Student Success (Corporate Activity Tax)

TABLE B.12 **Dec 2021**

Summary of Corporate Activity Tax Resources

(in millions of dollars)	2021-23 Current Forecast	2021-23 *Change from Sep-21*	2021-23 *Change from COS 2021*	2023-25 Current Forecast	2023-25 *Change from Sep-21*	2025-27 Current Forecast	2025-27 *Change from Sep-21*	2027-29 Current Forecast	2027-29 *Change from Sep-21*	2029-31 Current Forecast	2029-31 *Change from Sep-21*
Corporate Activity Tax											
+ Tax Revenue	2,392.736	15.968	*24.440*	2,719.803	*122.496*	3,021.593	*142.852*	3,350.442	*146.023*	3,701.875	*N/A*
- Administrative Costs	19.200	0.000	*0.000*	21.312	*0.000*	23.656	*0.000*	26.259	*0.000*	28.689	*N/A*
Net Available to Transfer	2,373.536	15.968	24.440	2,698.491	122.496	2,997.936	142.852	3,324.184	146.023	3,673.186	N/A
Fund for Student Success											
Beginning Balance	168.800	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*	0.000	*N/A*
Revenue Transfers	2,373.536	15.968	*24.440*	2,698.491	*122.496*	2,997.936	*142.852*	3,324.184	*146.023*	3,673.186	*N/A*
Other Resources	0.000	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*	0.000	*0.000*	0.000	*N/A*
Total Available Resources	2,542.337	15.968	24.440	2,698.491	122.496	2,997.936	142.852	3,324.184	146.023	3,673.186	N/A
ALLOCATION OF RESOURCES											
State School Fund	685.678	(7.447)	*0.000*	764.379	*0.000*	833.183	*0.000*	909.194	*0.000*	986.167	*N/A*
Student Investment Account	892.277	(24.345)	*0.000*	967.056	*61.248*	1,082.377	*71.426*	1,207.495	*73.012*	1,343.509	*N/A*
Statewide Education Initiative Account	372.901	(177.072)	*0.000*	580.234	*36.749*	649.426	*42.856*	724.497	*43.807*	806.106	*N/A*
Early Learning Account	436.107	69.458	*0.000*	386.822	*24.499*	432.951	*28.570*	482.998	*29.205*	537.404	*N/A*
Total Distributions	2,386.963	(139.406)	0.000	2,698.491	122.496	2,997.936	142.852	3,324.184	146.023	3,673.186	N/A
Ending Balance	155.374	155.374	24.440	0.000	0.000	0.000	0.000	0.000	0.000	0.000	N/A

Note: Some totals may not foot due to rounding.

Table B.13 Fund for Student Success Quarterly Revenues (Corporate Activity Tax)

Table B.13 **Corporate Activity Tax Collections By Quarter** **Dec-21**

(thousands)	2019:3	2019:4	2020:1	2020:2	FY 2020	2020:3	2020:4	2021:1	2021:2	FY 2021
Estimated Payments	$0	$0	$4,022.75	$222,495	$226,518	$224,973	$254,387	$223,550	$270,784	$973,693
Final Payments	$0	$0	$0	$0	$0	$0	$0	$26,911	$163,436	$190,348
Refunds (-)	$0	$0	$0	$0	$0	$0	$0	$997.05	$14,657	$15,654
Total	$0	$0	$4,023	$222,495	$226,518	$224,973	$254,387	$249,464	$419,563	$1,148,387

	2021:3	2021:4	2022:1	2022:2	FY 2022	2022:3	2022:4	2023:1	2023:2	FY 2023
Estimated Payments	$313,979	$275,068	$234,430	$271,147	$1,094,624	$316,064	$276,894	$247,629	$286,413	$1,127,001
Final Payments	$15,149	$27,967	$23,507	$94,030	$160,653	$58,769	$58,769	$45,662	$79,908	$243,108
Refunds (-)	$13,051	$74,290	$15,895	$15,895	$119,132	$15,895	$58,283	$24,587	$14,752	$113,517
Total	$316,077	$228,745	$242,042	$349,281	$1,136,145	$358,937	$277,380	$268,704	$351,570	$1,256,591

	2023:3	2023:4	2024:1	2024:2	FY 2024	2024:3	2024:4	2025:1	2025:2	FY 2025
Estimated Payments	$333,859	$292,484	$261,023	$301,905	$1,189,271	$351,917	$308,304	$275,100	$318,186	$1,253,507
Final Payments	$45,662	$57,077	$48,233	$84,407	$235,380	$48,233	$60,291	$50,842	$88,973	$248,338
Refunds (-)	$14,752	$44,256	$25,971	$15,583	$100,562	$15,583	$46,748	$27,376	$16,425	$106,131
Total	$364,769	$305,306	$283,285	$370,730	$1,324,089	$384,567	$321,848	$298,566	$390,734	$1,395,714

	2025:3	2025:4	2026:1	2026:2	FY 2026	2026:3	2026:4	2027:1	2027:2	FY 2027
Estimated Payments	$370,896	$324,931	$290,076	$335,508	$1,321,411	$391,087	$342,620	$305,372	$353,200	$1,392,280
Final Payments	$50,842	$63,552	$53,584	$93,771	$261,748	$53,584	$66,979	$56,501	$98,876	$275,940
Refunds (-)	$16,425	$49,276	$28,852	$17,311	$111,865	$17,311	$51,934	$30,423	$18,254	$117,921
Total	$405,312	$339,207	$314,808	$411,968	$1,471,295	$427,360	$357,666	$331,450	$433,822	$1,550,298

	2027:3	2027:4	2028:1	2028:2	FY 2028	2028:3	2028:4	2029:1	2029:2	FY 2029
Estimated Payments	$411,709	$360,687	$321,607	$371,977	$1,465,980	$433,597	$379,862	$338,168	$391,133	$1,542,760
Final Payments	$56,501	$70,626	$59,480	$104,090	$290,696	$59,480	$74,350	$62,642	$109,624	$306,096
Refunds (-)	$18,254	$54,761	$32,027	$19,216	$124,258	$19,216	$57,649	$33,730	$20,238	$130,832
Total	$449,956	$376,552	$349,060	$456,851	$1,632,419	$473,861	$396,564	$367,081	$480,518	$1,718,024

	2029:3	2029:4	2030:1	2030:2	FY 2030	2030:3	2030:4	2031:1	2031:2	FY 2031
Estimated Payments	$455,926	$399,424	$355,002	$410,603	$1,620,954	$478,621	$419,306	$373,243	$431,701	$1,702,871
Final Payments	$62,642	$78,303	$65,868	$115,269	$322,081	$65,868	$82,335	$69,147	$121,007	$338,356
Refunds (-)	$20,238	$60,713	$35,467	$21,280	$137,698	$21,280	$63,840	$37,232	$22,339	$144,691
Total	$498,330	$417,013	$385,403	$504,592	$1,805,338	$523,209	$437,802	$405,158	$530,368	$1,896,537

APPENDIX C: POPULATION FORECASTS BY AGE AND SEX

Table C.1 Oregon's Population Forecasts and Component of Change 1990-2029

Year		Population Change		Births		Deaths		Natural	Net Migration	
(July 1)	Population	Number	Percent	Number	Rate/1000	Number	Rate/1000	Increase	Number	Rate/1000
1990	2,860,400	69,800	2.50	42,008	14.87	24,763	8.76	17,245	52,555	18.60
1991	2,928,500	68,100	2.38	42,682	14.75	24,944	8.62	17,738	50,362	17.40
1992	2,991,800	63,300	2.16	42,427	14.33	25,166	8.50	17,261	46,039	15.55
1993	3,060,400	68,600	2.29	41,442	13.69	26,543	8.77	14,899	53,701	17.75
1994	3,121,300	60,900	1.99	41,487	13.42	27,564	8.92	13,923	46,977	15.20
1995	3,184,400	63,100	2.02	42,426	13.46	27,552	8.74	14,874	48,226	15.30
1990-1995		**324,000**		**210,464**		**131,769**		**78,695**	**245,305**	
1996	3,247,100	62,700	1.97	43,196	13.43	28,768	8.95	14,428	48,272	15.01
1997	3,304,300	57,200	1.76	43,625	13.32	29,201	8.91	14,424	42,776	13.06
1998	3,352,400	48,100	1.46	44,696	13.43	28,705	8.62	15,991	32,109	9.65
1999	3,393,900	41,500	1.24	45,188	13.40	29,848	8.85	15,340	26,160	7.76
2000	3,431,100	37,200	1.10	45,534	13.34	28,909	8.47	16,625	20,575	6.03
1995-2000		**246,700**		**222,239**		**145,431**		**76,808**	**169,892**	
2001	3,470,400	39,300	1.15	45,536	13.20	29,934	8.67	15,602	23,698	6.87
2002	3,502,600	32,200	0.93	44,995	12.91	30,828	8.84	14,167	18,033	5.17
2003	3,538,600	36,000	1.03	45,686	12.98	30,604	8.69	15,082	20,918	5.94
2004	3,578,900	40,300	1.14	45,599	12.81	30,721	8.63	14,878	25,422	7.14
2005	3,626,900	48,000	1.34	45,892	12.74	30,717	8.53	15,175	32,825	9.11
2000-2005		**195,800**		**227,708**		**152,804**		**74,904**	**120,896**	
2006	3,685,200	58,300	1.61	46,946	12.84	30,771	8.42	16,175	42,125	11.52
2007	3,739,400	54,200	1.47	49,404	13.31	31,396	8.46	18,008	36,192	9.75
2008	3,784,200	44,800	1.20	49,659	13.20	32,008	8.51	17,651	27,149	7.22
2009	3,815,800	31,600	0.84	47,960	12.62	31,382	8.26	16,578	15,022	3.95
2010	3,837,300	21,500	0.56	46,256	12.09	31,689	8.28	14,567	6,933	1.81
2005-2010		**210,400**		**240,225**		**157,246**		**82,979**	**127,421**	
2011	3,857,625	20,325	0.53	45,381	11.80	32,437	8.43	12,944	7,381	1.92
2012	3,878,877	21,252	0.55	44,897	11.61	32,804	8.48	12,093	9,159	2.37
2013	3,911,943	33,066	0.85	44,969	11.54	33,168	8.51	11,801	21,265	5.46
2014	3,953,356	41,413	1.06	45,447	11.56	33,731	8.58	11,716	29,697	7.55
2015	4,002,145	48,789	1.23	45,660	11.48	35,318	8.88	10,342	38,447	9.67
2010-2015		**164,845**		**226,354**		**167,458**		**58,896**	**105,949**	
2016	4,062,203	60,058	1.50	45,647	11.32	35,339	8.76	10,308	49,750	12.34
2017	4,124,435	62,232	1.53	44,602	10.90	36,773	8.98	7,829	54,403	13.29
2018	4,176,095	51,660	1.25	42,906	10.34	36,268	8.74	6,638	45,022	10.85
2019	4,214,664	38,569	0.92	42,220	10.06	36,622	8.73	5,598	32,971	7.86
2020	4,243,791	29,127	0.69	40,920	9.68	37,821	8.94	3,099	26,028	6.15
2015-2020		**241,646**		**216,295**		**182,823**		**33,472**	**208,174**	
2021	4,266,560	22,769	0.54	39,849	9.36	41,812	9.83	-1,963	24,732	5.81
2022	4,296,800	30,240	0.71	40,021	9.35	41,485	9.69	-1,463	31,703	7.40
2023	4,331,100	34,300	0.80	40,579	9.41	41,192	9.55	-613	34,913	8.09
2024	4,366,900	35,800	0.83	41,235	9.48	42,077	9.68	-842	36,642	8.43
2025	4,404,000	37,100	0.85	41,869	9.55	42,281	9.64	-413	37,513	8.55
2020-2025		**160,209**		**203,553**		**208,847**		**-5,294**	**165,503**	
2026	4,441,400	37,400	0.85	42,039	9.51	42,939	9.71	-900	38,300	8.66
2027	4,478,600	37,200	0.84	42,208	9.46	44,039	9.87	-1,832	39,032	8.75
2028	4,515,600	37,000	0.83	42,396	9.43	45,033	10.01	-2,637	39,637	8.81
2029	4,552,400	36,800	0.81	42,577	9.39	45,906	10.12	-3,328	40,128	8.85
1990-2000		**570,700**		**432,703**		**277,200**		**155,503**	**415,197**	13.10
2000-2010		**406,200**		**467,933**		**310,050**		**157,883**	**248,317**	6.83
2010-2020		**406,491**		**442,649**		**350,281**		**92,368**	**314,123**	7.81
2020-2029		**308,609**		**372,773**		**386,764**		**-13,991**	**322,600**	7.38

Sources: 1990-1999 population - U.S. Census Bureau; 2000-2019 intercensal population estimates by Office of Economic Analysis based on postcensal estimates by Population Research Center, PSU; births and deaths 1990-2020: Oregon Center for Health Statistics.

Table C.2 Population Forecasts by Age and Sex: 2010-2029

		2010			2011			2012			2013			2014	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	122,327	116,130	238,457	120,999	115,034	236,033	119,368	113,272	232,641	118,109	111,740	229,849	117,668	111,372	229,040
5- 9	121,539	116,369	237,908	121,706	115,841	237,547	122,610	116,807	239,417	123,829	117,817	241,646	124,460	117,856	242,316
10-14	124,508	118,732	243,241	124,040	119,003	243,044	123,544	118,207	241,752	123,300	118,084	241,383	123,282	118,295	241,577
15-19	131,126	124,540	255,667	128,969	121,863	250,832	127,353	120,491	247,844	126,427	119,755	246,182	126,589	119,827	246,416
20-24	128,787	124,903	253,689	130,401	126,459	256,860	132,554	128,395	260,949	134,876	130,179	265,055	136,217	131,447	267,664
25-29	134,019	131,816	265,835	133,068	130,550	263,617	132,041	129,412	261,452	131,905	129,647	261,551	133,793	131,873	265,667
30-34	131,489	128,325	259,814	133,348	130,625	263,973	135,368	133,076	268,445	136,827	134,655	271,483	139,247	136,795	276,042
35-39	128,070	123,596	251,665	125,855	121,752	247,606	125,885	122,211	248,097	128,469	124,236	252,705	130,544	126,405	256,949
40-44	125,969	122,843	248,811	128,897	125,300	254,197	130,652	126,513	257,165	131,278	127,313	258,591	130,784	126,505	257,289
45-49	130,825	132,538	263,363	127,727	128,492	256,219	125,313	124,894	250,206	123,689	122,067	245,756	124,077	121,326	245,403
50-54	135,129	141,565	276,693	134,634	140,575	275,210	133,356	139,058	272,414	131,943	137,349	269,292	131,379	135,892	267,271
55-59	133,011	140,802	273,812	133,929	142,260	276,189	134,269	142,897	277,166	134,196	142,517	276,713	133,125	141,747	274,872
60-64	115,236	121,045	236,281	121,356	127,759	249,114	122,764	129,435	252,198	124,690	132,645	257,335	127,440	136,590	264,030
65-69	81,854	87,917	169,771	84,379	90,814	175,193	92,005	98,707	190,711	97,839	104,935	202,774	103,339	110,315	213,653
70-74	56,925	62,949	119,874	59,468	65,626	125,094	62,458	69,084	131,542	67,117	73,850	140,967	71,201	78,399	149,599
75-79	40,932	50,101	91,034	41,536	50,064	91,601	42,634	50,672	93,306	44,196	52,033	96,229	46,407	54,102	100,508
80-84	30,391	42,734	73,126	30,483	42,280	72,763	30,527	41,809	72,336	30,726	41,238	71,964	30,984	40,760	71,745
85+	26,800	51,458	78,258	27,588	52,267	79,855	28,339	52,897	81,235	28,961	53,507	82,467	29,471	53,844	83,315
Total	1,898,938	1,938,362	3,837,300	1,908,385	1,946,562	3,854,947	1,921,040	1,957,837	3,878,877	1,938,377	1,973,566	3,911,943	1,960,005	1,993,351	3,953,356
Mdn. Age	37.2	39.4	38.3	37.4	39.7	38.6	37.6	39.9	38.7	37.8	40.0	38.9	38.0	40.1	39.0

		2015			2016			2017			2018			2019	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	117,860	111,418	229,278	118,852	112,058	230,910	119,352	112,540	231,892	118,419	111,558	229,977	116,341	109,681	226,022
5- 9	125,142	118,090	243,232	125,105	117,846	242,951	124,758	116,968	241,726	124,210	115,861	240,072	123,988	115,573	239,561
10-14	122,812	118,117	240,928	123,591	118,379	241,970	125,277	120,259	245,536	126,884	121,719	248,603	127,626	121,848	249,474
15-19	127,444	120,458	247,903	128,129	121,427	249,556	128,794	121,620	250,413	128,853	121,663	250,516	128,536	121,677	250,213
20-24	136,686	131,964	268,650	136,827	131,897	268,723	137,370	132,538	269,909	137,371	132,702	270,073	137,296	132,232	269,527
25-29	136,997	135,808	272,805	142,502	142,408	284,910	148,053	148,567	296,619	152,587	153,226	305,813	154,142	154,897	309,039
30-34	140,637	137,861	278,499	142,965	139,621	282,586	144,886	141,502	286,388	146,601	143,728	290,329	149,151	146,978	296,129
35-39	134,041	129,570	263,611	137,586	132,763	270,350	141,536	136,476	278,012	144,135	138,715	282,850	147,041	141,179	288,220
40-44	129,724	125,081	254,805	128,681	124,068	252,749	129,777	125,389	255,166	133,049	127,846	260,895	135,248	130,056	265,304
45-49	126,762	123,353	250,116	130,874	126,559	257,433	133,712	128,530	262,242	134,953	129,740	264,693	134,524	128,971	263,495
50-54	129,738	133,279	263,017	127,552	130,298	257,851	126,040	127,481	253,521	124,925	125,074	249,999	125,494	124,296	249,790
55-59	132,989	141,912	274,901	133,507	142,289	275,796	132,932	141,770	274,702	131,963	140,651	272,615	131,363	139,169	270,532
60-64	130,018	139,366	269,383	132,412	142,012	274,424	133,918	143,740	277,658	134,609	144,015	278,624	133,620	143,357	276,978
65-69	109,644	117,322	226,966	116,497	124,661	241,158	118,782	127,109	245,890	121,331	130,754	252,086	124,204	134,715	258,919
70-74	74,718	82,405	157,123	77,506	85,468	162,973	85,146	93,414	178,560	91,054	99,616	190,670	96,403	104,814	201,217
75-79	48,565	56,028	104,593	50,933	58,621	109,553	53,652	61,930	115,582	57,869	66,359	124,228	61,499	70,495	131,995
80-84	31,632	40,772	72,405	32,422	40,887	73,309	33,490	41,505	74,995	34,943	42,714	77,657	36,791	44,462	81,252
85+	30,026	53,904	83,930	30,745	54,255	85,000	31,314	54,308	85,622	32,020	54,376	86,396	32,656	54,342	86,997
Total	1,985,437	2,016,709	4,002,145	2,016,686	2,045,517	4,062,203	2,048,789	2,075,646	4,124,435	2,075,777	2,100,318	4,176,095	2,095,922	2,118,742	4,214,664
Mdn. Age	38.1	40.2	39.1	38.2	40.3	39.2	38.3	40.3	39.3	38.5	40.4	39.4	38.8	40.6	39.6

		2020			2021			2022			2023			2024	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	113,260	106,931	220,192	109,715	103,707	213,423	107,202	101,354	208,555	106,092	100,266	206,358	105,738	99,875	205,614
5- 9	123,931	115,417	239,348	124,184	115,602	239,786	123,894	115,389	239,283	122,447	114,152	236,599	120,301	112,263	232,564
10-14	128,201	121,882	250,083	127,783	121,162	248,946	126,925	119,684	246,609	126,142	118,316	244,457	125,904	118,057	243,960
15-19	127,439	121,122	248,561	127,572	120,945	248,517	128,776	122,446	251,223	130,381	123,855	254,237	131,323	124,036	255,359
20-24	137,175	131,545	268,720	136,447	131,035	267,482	135,951	130,011	265,962	135,722	130,010	265,733	135,637	130,456	266,093
25-29	153,302	153,797	307,100	151,151	150,695	301,846	149,763	149,155	298,919	149,003	148,225	297,229	149,283	148,134	297,417
30-34	151,909	150,900	302,809	155,853	156,135	311,988	160,060	160,995	321,055	163,722	164,407	328,129	165,475	166,033	331,509
35-39	148,252	142,226	290,478	149,579	143,454	293,033	150,405	144,502	294,907	151,427	146,309	297,736	154,017	149,539	303,556
40-44	138,502	132,987	271,489	141,431	135,765	277,196	144,624	138,848	283,472	147,007	140,997	288,005	150,079	143,621	293,700
45-49	133,124	127,339	260,462	131,354	125,880	257,234	131,879	126,729	258,609	134,893	129,018	263,911	137,172	131,272	268,444
50-54	128,077	126,009	254,086	131,639	128,678	260,317	133,892	130,171	264,063	134,765	131,223	265,988	134,317	130,561	264,877
55-59	129,398	136,078	265,475	126,637	132,283	258,920	124,704	128,955	253,659	123,494	126,288	249,782	124,144	125,613	249,757
60-64	133,067	143,221	276,288	132,610	142,810	275,420	131,457	141,758	273,215	130,154	140,293	270,447	129,638	138,861	268,499
65-69	126,505	137,205	263,710	127,943	139,143	267,086	128,827	140,295	269,122	129,113	140,348	269,462	128,154	139,798	267,953
70-74	102,222	111,379	213,602	107,836	117,835	225,671	109,507	119,823	229,330	111,553	123,132	234,685	114,139	126,883	241,023
75-79	64,567	74,042	138,609	66,588	76,494	143,082	73,023	83,466	156,489	78,063	89,063	167,126	82,583	93,777	176,361
80-84	38,526	46,079	84,605	40,020	48,054	88,073	41,957	50,680	92,637	45,201	54,364	99,564	48,038	57,814	105,852
85+	33,582	54,593	88,175	33,942	54,598	88,540	34,650	55,041	89,691	35,661	55,992	91,653	37,009	57,354	94,363
Total	2,111,039	2,132,752	4,243,791	2,122,284	2,144,276	4,266,560	2,137,497	2,159,303	4,296,800	2,154,841	2,176,260	4,331,100	2,172,953	2,193,947	4,366,900
Mdn. Age	39.0	40.8	39.9	39.3	41.0	40.1	39.5	41.3	40.4	39.7	41.5	40.6	40.0	41.7	40.8

		2025			2026			2027			2028			2029	
Age	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total	Male	Female	Total
0-4	106,387	100,434	206,822	107,654	101,584	209,238	108,882	102,707	211,589	109,896	103,634	213,529	110,646	104,316	214,962
5- 9	117,415	109,630	227,044	114,131	106,546	220,677	111,715	104,229	215,945	110,676	103,163	213,838	110,397	102,793	213,190
10-14	125,980	118,095	244,075	126,431	118,521	244,952	126,216	118,413	244,629	124,774	117,199	241,973	122,610	115,294	237,904
15-19	132,192	124,206	256,398	132,026	123,632	255,658	131,271	122,186	253,457	130,528	120,805	251,333	130,319	120,545	250,863
20-24	134,999	130,468	265,467	135,698	130,816	266,514	137,258	132,726	269,984	139,136	134,438	273,574	140,258	134,792	275,050
25-29	150,124	148,653	298,777	150,428	149,532	299,960	150,463	149,145	299,607	150,563	149,618	300,182	150,716	150,478	301,194
30-34	165,510	165,720	331,230	164,399	163,645	328,044	163,521	162,655	326,176	163,063	162,019	325,082	163,650	162,194	325,843
35-39	157,353	153,769	311,122	162,141	159,504	321,645	166,839	164,617	331,456	170,788	168,138	338,926	172,701	169,810	342,510
40-44	151,653	144,927	296,581	153,423	146,436	299,859	154,485	147,636	302,122	155,664	149,555	305,219	158,420	152,903	311,323
45-49	140,781	134,424	275,205	144,171	137,488	281,659	147,649	140,741	288,391	150,221	142,992	293,213	153,464	145,707	299,170
50-54	133,174	129,188	262,361	131,780	128,027	259,807	132,513	129,072	261,585	135,664	131,517	267,180	138,042	133,910	271,952
55-59	126,918	127,667	254,585	130,772	130,778	261,550	133,213	132,533	265,746	134,230	133,758	267,988	133,915	133,207	267,122
60-64	128,078	136,103	264,181	125,882	132,732	258,614	124,272	129,627	253,899	123,272	127,103	250,375	124,109	126,572	250,681
65-69	127,953	139,991	267,945	128,070	140,018	268,089	127,285	139,240	266,525	126,237	137,968	264,204	125,916	136,690	262,606
70-74	116,494	129,454	245,948	118,305	131,641	249,946	119,436	132,962	252,398	119,918	133,186	253,104	119,220	132,814	252,034
75-79	87,622	99,807	187,429	92,713	105,825	198,538	94,457	107,906	202,363	96,457	111,118	207,576	98,916	114,678	213,595
80-84	50,567	60,844	111,411	52,488	63,114	115,602	57,962	69,243	127,206	62,304	74,156	136,460	66,173	78,269	144,442
85+	38,577	58,842	97,419	40,220	60,827	101,047	42,157	63,367	105,524	45,029	66,814	111,843	47,744	70,212	117,956
Total	2,191,778	2,212,222	4,404,000	2,210,733	2,230,667	4,441,400	2,229,595	2,249,006	4,478,600	2,248,420	2,267,180	4,515,600	2,267,217	2,285,183	4,552,400
Mdn. Age	40.2	41.9	41.0	40.4	42.1	41.2	40.6	42.3	41.4	40.8	42.5	41.6	41.0	42.7	41.8

Table C.3 Population of Oregon: 1990-2029

Year (July 1)	Total Population	Change from previous year Number	Percent
1990	2,860,400	-	-
1991	2,928,500	68,100	2.38%
1992	2,991,800	63,300	2.16%
1993	3,060,400	68,600	2.29%
1994	3,121,300	60,900	1.99%
1995	3,184,400	63,100	2.02%
1996	3,247,100	62,700	1.97%
1997	3,304,300	57,200	1.76%
1998	3,352,400	48,100	1.46%
1999	3,393,900	41,500	1.24%
2000	3,431,100	37,200	1.10%
2001	3,470,400	39,300	1.15%
2002	3,502,600	32,200	0.93%
2003	3,538,600	36,000	1.03%
2004	3,578,900	40,300	1.14%
2005	3,626,900	48,000	1.34%
2006	3,685,200	58,300	1.61%
2007	3,739,400	54,200	1.47%
2008	3,784,200	44,800	1.20%
2009	3,815,800	31,600	0.84%
2010	3,837,300	21,500	0.56%
2011	3,854,947	17,647	0.46%
2012	3,878,877	23,930	0.62%
2013	3,911,943	33,066	0.85%
2014	3,953,356	41,413	1.06%
2015	4,002,145	48,789	1.23%
2016	4,062,203	60,058	1.50%
2017	4,124,435	62,232	1.53%
2018	4,176,095	51,660	1.25%
2019	4,214,664	38,569	0.92%
2020	4,243,791	29,127	0.69%
2021	4,266,560	22,770	0.54%
2022	4,296,800	30,239	0.71%
2023	4,331,100	34,301	0.80%
2024	4,366,900	35,800	0.83%
2025	4,404,000	37,100	0.85%
2026	4,441,400	37,400	0.85%
2027	4,478,600	37,200	0.84%
2028	4,515,600	37,000	0.83%
2029	4,552,400	36,800	0.81%

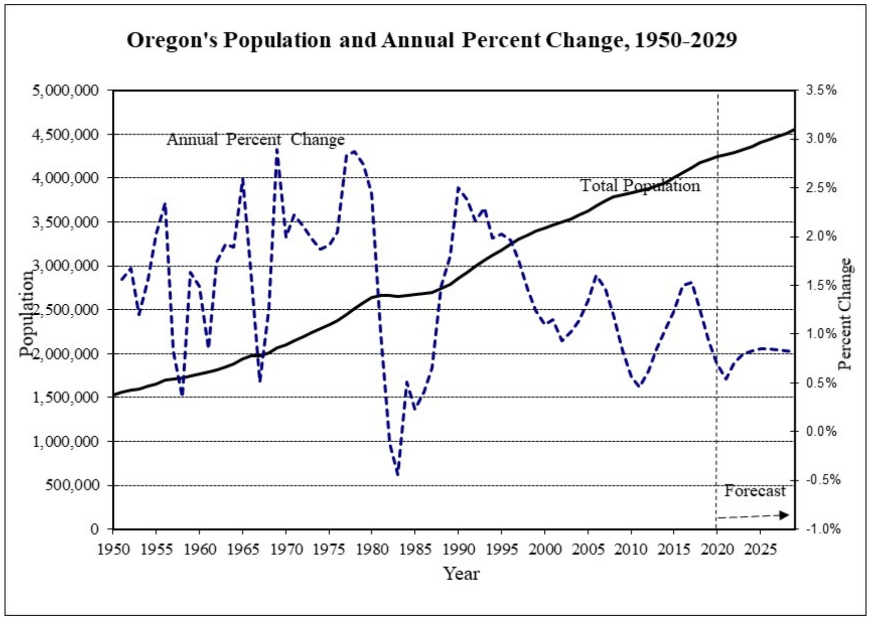


Table C.4 Children: Ages 0-4 / Table C.5 School Age Population: Ages 5-17 / Table C.6 Young Adult Population: Ages 18-24

Year (July 1)	C.4 Population	% Change from previous decade/yr. Number	Percent	C.5 Population	% Change from previous decade/yr. Number	Percent	C.6 Population	% Change from previous decade/yr. Number	Percent
1980	199,525	---	---	524,446	---	---	329,407	---	---
1990	209,638	10,113	5.07%	532,727	8,281	1.58%	268,134	-61,273	-18.60%
2000	223,207	13,569	6.47%	624,316	91,589	17.19%	330,328	62,194	23.20%
2001	224,645	1,438	0.64%	624,675	358	0.06%	336,660	6,333	1.92%
2002	225,084	439	0.20%	624,611	-64	-0.01%	340,778	4,118	1.22%
2003	226,652	1,568	0.70%	624,349	-262	-0.04%	345,266	4,487	1.32%
2004	228,353	1,701	0.75%	625,461	1,112	0.18%	349,138	3,873	1.12%
2005	230,008	1,655	0.72%	628,326	2,865	0.46%	351,076	1,938	0.55%
2006	231,882	1,874	0.81%	633,646	5,320	0.85%	354,328	3,252	0.93%
2007	236,160	4,278	1.85%	635,720	2,074	0.33%	356,311	1,983	0.56%
2008	239,340	3,180	1.35%	635,372	-348	-0.05%	358,967	2,656	0.75%
2009	239,929	589	0.25%	633,575	-1,797	-0.28%	360,134	1,166	0.32%
2010	238,457	-1,472	-0.61%	630,741	-2,835	-0.45%	359,764	-370	-0.10%
2011	236,033	-2,424	-1.02%	628,103	-2,638	-0.42%	360,180	416	0.12%
2012	232,641	-3,392	-1.44%	628,214	111	0.02%	361,748	1,568	0.44%
2013	229,849	-2,792	-1.20%	629,466	1,251	0.20%	364,800	3,053	0.84%
2014	229,040	-809	-0.35%	630,820	1,354	0.22%	367,153	2,353	0.64%
2015	229,278	238	0.10%	632,114	1,294	0.21%	368,599	1,446	0.39%
2016	230,910	1,632	0.71%	634,041	1,927	0.30%	369,160	561	0.15%
2017	231,892	982	0.43%	636,366	2,325	0.37%	371,218	2,058	0.56%
2018	229,977	-1,915	-0.83%	636,368	2	0.00%	372,896	1,678	0.45%
2019	226,022	-3,955	-1.72%	636,593	225	0.04%	372,182	-713	-0.19%
2020	220,192	-5,830	-2.58%	637,442	849	0.13%	369,271	-2,912	-0.78%
2021	213,423	-6,769	-3.07%	637,948	506	0.08%	366,783	-2,488	-0.67%
2022	208,555	-4,867	-2.28%	636,839	-1,108	-0.17%	366,237	-546	-0.15%
2023	206,358	-2,197	-1.05%	634,288	-2,552	-0.40%	366,738	501	0.14%
2024	205,614	-744	-0.36%	630,228	-4,059	-0.64%	367,748	1,010	0.28%
2025	206,822	1,208	0.59%	623,687	-6,541	-1.04%	369,297	1,549	0.42%
2026	209,238	2,416	1.17%	615,925	-7,762	-1.24%	371,876	2,579	0.70%
2027	211,589	2,351	1.12%	609,424	-6,501	-1.06%	374,591	2,715	0.73%
2028	213,529	1,940	0.92%	603,910	-5,514	-0.90%	376,809	2,218	0.59%
2029	214,962	1,433	0.67%	600,021	-3,889	-0.64%	376,987	178	0.05%

Table C.7 Criminally At Risk Population (males): Ages 15-39

Table C.8 Prime Wage Earners: Ages 25-44

Table C.9 Older Wage Earners: Ages 45-64

Year	C.7	% Change from previous decade/yr.		C.8	% Change from previous decade/yr.		C.9	% Change from previous decade/yr.	
(July 1)	Population	Number	Percent	Population	Number	Percent	Population	Number	Percent
1980	561,931	---	---	790,750	---	---	491,249	---	---
1990	544,738	-17,193	-3.06%	926,326	135,576	17.15%	531,181	39,932	8.13%
2000	616,988	72,250	13.26%	996,500	70,174	7.58%	817,510	286,329	53.90%
2001	618,906	1,918	0.31%	994,587	-1,913	-0.19%	847,276	29,766	3.64%
2002	620,252	1,347	0.22%	989,996	-4,591	-0.46%	876,242	28,966	3.42%
2003	622,211	1,959	0.32%	987,755	-2,241	-0.23%	903,499	27,257	3.11%
2004	626,423	4,212	0.68%	988,932	1,177	0.12%	930,032	26,533	2.94%
2005	633,901	7,478	1.19%	994,575	5,644	0.57%	957,826	27,793	2.99%
2006	644,210	10,309	1.63%	1,004,110	9,535	0.96%	985,638	27,813	2.90%
2007	652,287	8,077	1.25%	1,014,565	10,455	1.04%	1,008,986	23,348	2.37%
2008	657,248	4,961	0.76%	1,022,060	7,495	0.74%	1,025,501	16,515	1.64%
2009	657,327	79	0.01%	1,024,971	2,911	0.28%	1,039,689	14,188	1.38%
2010	653,491	-3,836	-0.58%	1,026,126	1,155	0.11%	1,050,150	10,461	1.01%
2011	651,641	-1,850	-0.28%	1,029,393	3,268	0.32%	1,056,732	6,582	0.63%
2012	653,201	1,560	0.24%	1,035,159	5,765	0.56%	1,051,985	-4,747	-0.45%
2013	658,504	5,303	0.81%	1,044,330	9,171	0.89%	1,049,096	-2,889	-0.27%
2014	666,390	7,887	1.20%	1,055,947	11,618	1.11%	1,051,575	2,479	0.24%
2015	675,806	9,416	1.41%	1,069,720	13,772	1.30%	1,057,417	5,842	0.56%
2016	688,009	12,203	1.81%	1,090,595	20,875	1.95%	1,065,504	8,087	0.76%
2017	700,639	12,630	1.84%	1,116,186	25,591	2.35%	1,068,123	2,619	0.25%
2018	709,548	8,909	1.27%	1,139,887	23,701	2.12%	1,065,931	-2,192	-0.21%
2019	716,165	6,618	0.93%	1,158,692	18,805	1.65%	1,060,795	-5,137	-0.48%
2020	718,078	1,912	0.27%	1,171,876	13,183	1.14%	1,056,311	-4,484	-0.42%
2021	720,602	2,524	0.35%	1,184,064	12,188	1.04%	1,051,891	-4,420	-0.42%
2022	724,956	4,354	0.60%	1,198,353	14,289	1.21%	1,049,546	-2,345	-0.22%
2023	730,256	5,300	0.73%	1,211,098	12,745	1.06%	1,050,127	581	0.06%
2024	735,736	5,480	0.75%	1,226,182	15,084	1.25%	1,051,577	1,450	0.14%
2025	740,178	4,442	0.60%	1,237,709	11,527	0.94%	1,056,333	4,755	0.45%
2026	744,692	4,514	0.61%	1,249,509	11,799	0.95%	1,061,630	5,298	0.50%
2027	749,351	4,660	0.63%	1,259,361	9,852	0.79%	1,069,621	7,990	0.75%
2028	754,079	4,728	0.63%	1,269,409	10,048	0.80%	1,078,756	9,136	0.85%
2029	757,643	3,564	0.47%	1,280,871	11,462	0.90%	1,088,926	10,170	0.94%

Table C.10 Elderly Population by Age Group

Year (July 1)	Ages 65+	%Change from previous decade/yr.	Ages 65-74	%Change from previous decade/yr.	Ages 75-84	%Change from previous decade/yr.	Ages 85+	%Change from previous decade/yr.
1980	305,841	---	185,863	---	91,137	---	28,841	---
1990	392,369	28.29%	224,772	20.93%	128,813	41.34%	38,784	34.48%
2000	439,239	11.95%	218,997	-2.57%	162,187	25.91%	58,055	49.69%
2001	442,558	0.76%	218,838	-0.07%	163,878	1.04%	59,843	3.08%
2002	445,890	0.75%	219,614	0.35%	165,109	0.75%	61,167	2.21%
2003	451,080	1.16%	222,361	1.25%	165,669	0.34%	63,050	3.08%
2004	456,984	1.31%	226,373	1.80%	165,842	0.10%	64,769	2.73%
2005	465,089	1.77%	231,926	2.45%	166,077	0.14%	67,087	3.58%
2006	475,596	2.26%	239,931	3.45%	165,787	-0.17%	69,877	4.16%
2007	487,657	2.54%	250,131	4.25%	165,148	-0.39%	72,379	3.58%
2008	502,959	3.14%	264,201	5.63%	164,354	-0.48%	74,403	2.80%
2009	517,502	2.89%	277,606	5.07%	163,513	-0.51%	76,383	2.66%
2010	532,062	2.81%	289,645	4.34%	164,159	0.40%	78,258	2.45%
2011	544,506	2.34%	300,288	3.67%	164,364	0.12%	79,855	2.04%
2012	569,131	4.52%	322,254	7.32%	165,642	0.78%	81,235	1.73%
2013	594,402	4.44%	343,741	6.67%	168,193	1.54%	82,467	1.52%
2014	618,820	4.11%	363,253	5.68%	172,253	2.41%	83,315	1.03%
2015	645,017	4.23%	384,089	5.74%	176,998	2.75%	83,930	0.74%
2016	671,994	4.18%	404,131	5.22%	182,863	3.31%	85,000	1.27%
2017	700,649	4.26%	424,450	5.03%	190,577	4.22%	85,622	0.73%
2018	731,036	4.34%	442,756	4.31%	201,884	5.93%	86,396	0.90%
2019	760,380	4.01%	460,136	3.93%	213,247	5.63%	86,997	0.70%
2020	788,700	3.72%	477,311	3.73%	223,214	4.67%	88,175	1.35%
2021	812,452	3.01%	492,757	3.24%	231,155	3.56%	88,540	0.41%
2022	837,269	3.05%	498,452	1.16%	249,126	7.77%	89,691	1.30%
2023	862,491	3.01%	504,147	1.14%	266,691	7.05%	91,653	2.19%
2024	885,551	2.67%	508,975	0.96%	282,213	5.82%	94,363	2.96%
2025	910,152	2.78%	513,893	0.97%	298,840	5.89%	97,419	3.24%
2026	933,222	2.53%	518,035	0.81%	314,140	5.12%	101,047	3.72%
2027	954,015	2.23%	518,923	0.17%	329,568	4.91%	105,524	4.43%
2028	973,187	2.01%	517,308	-0.31%	344,036	4.39%	111,843	5.99%
2029	990,634	1.79%	514,640	-0.52%	358,037	4.07%	117,956	5.47%

Exhibit 1505 is confidential and provided only in electronic format. Exhibit is subject to General Protective Order 21-206.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Corporate Support

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Jim Ajello
Greg Batzler

December 2, 2021

Table of Contents

I. Introduction

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

A. My name is Jim Ajello. I am the Senior Vice President, Chief Financial Officer (CFO), and Treasurer at PGE. My qualifications were previously provided in PGE Exhibit 400.

My name is Greg Batzler. I am a Regulatory Consultant in Regulatory Affairs at PGE. My qualifications were previously provided in PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address certain issues and proposed adjustments raised by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to PGE's 2022 test year revenue requirement.

Q. What specific issues do you address in your testimony and how is it organized?

A. We address the following issues:

- Section II - Administrative and General (A&G) Non-Labor Operations and Maintenance (O&M) Expenses;
- Section III – Property Insurance;
- Section IV - Other A&G Adjustments;
- Section V - Information Technology (IT); and
- Section VI - Summary and Conclusion.

II. A&G Non-Labor O&M Expenses

Q. Please describe Parties' issues regarding PGE's Non-Labor O&M expenses.

A. Staff recommends three separate adjustments to PGE's non-labor O&M based on their analysis of PGE's response to OPUC Standard Data Request No. 057, Attachment 057-B.[1] Using PGE's 2020 actual transaction level data, Staff adjusts PGE's 2022 forecast based on transactions that they indicate: 1) have no specific means of determining the nature of the expenditures in question; 2) are transactions labeled "gross earnings;" or 3) are transactions labeled "LL-Postretirement Service Cost." The sum of these amounts, which Staff proposes to eliminate from PGE's 2022 forecast, is approximately $45.3 million.[2] AWEC recommends an adjustment based on removing all escalation amounts and using PGE's 2019 budgeted O&M expenses. AWEC bases the reasonableness of this adjustment on their claim that PGE's 2022 amounts have no evidentiary basis and are not known and measurable.[3]

Q. How does PGE respond to Staff's concerns and issues raised regarding Standard Data Requests (SDRs)?

A. PGE agrees that some revised responses were necessary to provide additional information to PGE's responses to OPUC Standard Data Request Nos. 057 and 058.[4] The final detail PGE provided, however, was consistent between the responses and consistent with the level of detail and categorization of data as provided in response to the same SDRs from PGE's five previous general rate cases (GRCs).[5] PGE welcomes a collaborative discussion with Staff on

[1] A copy of PGE's response to OPUC SDR No. 057 is provided as PGE Exhibit 1601.
[2] Note that Staff appears to have inadvertently excluded FERC account 931 from their adjustment in total, leading to incorrectly summing their adjustment to $42.6 million.
[3] AWEC/100/page 26/lines 3-4.
[4] A copy of PGE's response to OPUC SDR No. 058 is provided as PGE Exhibit 1602.
[5] This coincides with the number GRCs PGE has filed since SDRs were required pursuant to OAR 860-022-0019(2)(a): UE 262, UE 283, UE 294, UE 319, and UE 335.

how best to modify the data provided in response to SDR Nos. 057 and 058 moving forward. Unfortunately, Staff's proposed adjustment is unfounded, is punitive in nature, and in many instances proposes duplicate adjustments to amounts PGE either voluntarily removed from the 2022 test year prior to filing or to adjustments Staff proposes elsewhere in their testimony.

Q. Approximately $5.3 million of Staff's adjustment is for 2020 transaction detail without a "specific means of determining the nature of the expenditures in question."[6] Are the 2020 transactions referenced lacking all discernable information?

A. No. The "760 individual line entries" referenced by Staff include numerous informational fields, including account work order descriptions, cost element (CE) descriptions, entry category descriptions, department descriptions, and account descriptions. There is no line description nor vendor description because these are predominantly non-labor-related allocations,[7] which are directly charged to a balance sheet clearing account and then systematically allocated to a variety of accounts based on PGE's cost allocation criteria.[8]

Q. Please briefly explain the purpose of cost allocations and how they work.

A. Allocations spread primary "service provider" costs to specific accounts. The service or cost is one that is shared, so when allocating the cost, it is first grouped by type (e.g., information technology, print and mail services, etc.) within the "balance" being allocated. The costs are then posted to a corresponding CE in the destination account. The non-labor costs identified by Staff, for example, are posted to either CE 2101 for storeroom materials, CE 5302 for storeroom overhead costs, or CE 5599 for all other non-labor allocated costs and are then allocated to their destination account. There are essentially two types of cost allocations:

[6] Staff/500/page 3/lines 1-2.
[7] Only two of the 760 entries identified do not relate to non-labor allocations.
[8] PGE's cost allocation manual is provided annually as part of its Affiliated Interest Report (Docket No. RE 64).

- Primary: costs are captured in a clearing account and then 100% allocated based on underlying criteria specific to the particular costs.
- Secondary: costs are recorded in certain income statement accounts ("balance accounts"), and then a portion of costs are reclassified to capital, co-ownership, and/or affiliate accounts. A credit corresponding to these reclassifications is then recorded on the income statement ("allocation credit accounts"). The balance and credit are in the same FERC account grouping.

Q. What allocation amounts are included in Staff's transaction amounts?

A. Using both the entry field and CE field included in Staff's work paper, Table 1 below provides a summary of the specific non-labor allocations. Confidential PGE Exhibit 1603 provides additional detail.

Table 1

CE	CE Description	Entry	Type	Total
5599	Non-Labor Allocation	CORP_GOVERN	Secondary	(5,280,612.87)
5599	Non-Labor Allocation	HELICOPTER	Primary	195,598.69
5599	Non-Labor Allocation	IT_SVC_PROVIDER	Primary	6,401,243.33
5599	Non-Labor Allocation	PRINT_MAIL_SVCS	Primary	44,485.52
5599	Non-Labor Allocation	TRANSPORTATION	Primary	21,741.43
5599	Non-Labor Allocation	WTC_COST_ALLOC	Primary	3,792,880.92
5599	Non-Labor Allocation	SRCXFR	Secondary	(1,281.78)
2101	Storeroom/Materials	TRANSPORTATION	Primary	(9.16)
2101	Storeroom/Materials	IT_SVC_PROVIDER	Primary	113.64
5302	Storeroom Overhead	MATERIALS_OH	Secondary	2,054.91
			Total	**5,176,214.62**

Q. Please provide a narrative description of these allocation entries.

A. Many of these allocated amounts were discussed in PGE's initial filing and we provide additional detail here.

- Corporate Governance: This is a secondary allocation as described above. In summary, certain departments are permitted to charge to allocable accounts within FERC accounts 920, 921, and 923. The accumulated costs in these accounts then form the balance of this allocation. The basis for allocating these costs is the percentage of capital, co-owned facility, affiliate, and certain balance sheet account labor. Then, the total amount reclassified to the above categories is credited to account 922, which is the 2020 amount provided above. PGE Exhibit 401 provides 2018 through 2022 Corporate Governance costs, which are forecast to decrease by $2.7 million in 2022 compared to 2020 actuals.

- Helicopter: For 2020, 50% of Aircraft Operations were allocated to A&G. This accounted for pilot downtime and administrative tasks, with the remaining amounts recorded to Transmission and Distribution (T&D). For the 2022 forecast, as evidenced in PGE's Exhibit 400 work paper, "Corp Supp Workpaper FINAL," tab "Service Providers," PGE has adjusted this allocation such that no amounts are allocated to A&G.
- IT Service Provider: All shared IT costs (i.e., those which cannot be direct charged) are allocated using the IT Service Provider allocator. After being charged to the IT Service Provider clearing account, costs are then allocated across several accounts, based on rates determined during the annual budgeting process. The rates are determined based on the percentage of total labor in each operating area (e.g., Generation, A&G, T&D, etc.). The amount referenced above is the amount allocated to A&G accounts. PGE Exhibit 400 discusses PGE's total IT O&M in detail for all operating areas, including the drivers between 2020 actuals and the 2022 forecast and direct versus allocated charges. Additionally, PGE Exhibit 400 work paper "IT Workpaper" and PGE Exhibit 405 provide extensive IT cost detail for 2018 actuals through the 2022 forecast.

- Print and Mail Services: This service provider account collects the allocable costs of the department providing printing, copying, and mailing services for PGE. The allocation rates are determined during the annual budget process, based on historical rates. PGE's Exhibit 400 work paper, "Corp Supp Workpaper FINAL_Errata," tab "Service Providers," provides 2018 actual through 2022 forecasted detail included in A&G.
- Transportation: The allocation of fleet vehicle related costs to the departments which operate the vehicles. The allocation rate is based on the actual labor percentage of total.
- World Trade Center (WTC) Rent: The total PGE rent at the WTC is spread across multiple operations that utilize the space. The rates are determined during the annual budgeting process based on labor percentage of total. PGE discusses WTC rent expense in multiple places within direct testimony including PGE Exhibit 400, PGE Exhibit 404, and PGE Exhibit 800. In total, WTC rent is forecast to decrease by approximately $2.4 million from 2020 to 2022.
- Source transfers: Like Corporate Governance costs, this is a secondary allocation, which credits O&M for the portion of costs attributed to capital, co-owned facilities, affiliates, and certain balance sheet accounts. Source transfers are not budgeted or forecasted.
- Materials Overhead: The allocation of overhead cost related to materials inventory to various PGE operating department, co-owned facilities, and non-utility operations.

Q. Please describe the remainder of Staff's proposed adjustment.

A. For the remaining $40.0 million of their proposed non-labor A&G adjustment, Staff identifies entries in PGE's response to OPUC SDR No. 057, Attachment 057-B they classify as labor or labor loading related. Then, based on this assumption, Staff adjusts PGE's non-labor expense by the amount identified.

Q. What basis does Staff provide for this part of their adjustment?

A. It is unclear to PGE what the reasoning is for adjusting PGE's <u>2022</u> forecasted <u>non-labor</u> A&G expense by <u>2020</u> <u>labor-related</u> transaction-level data Staff identified within a data response.

Q. Does Staff question the prudency of these costs?

A. No. Staff does not argue that any of these costs were imprudently incurred, nor do they provide any reasoning as to why or how it is appropriate to adjust PGE's 2022 forecast based on amounts Staff believes should not be included within a non-labor data set.

Q. Is there any possibility that PGE is somehow double counting these costs in the 2022 test year forecast?

A. No. PGE's departments budget using a full accounting string (operating unit, account, CE, etc.) to separately identify projected costs. There is no opportunity for the same cost to be included twice. We provide more detail regarding PGE's budgeting process below. However, as we also explain below, Staff's adjustment is effectively double cutting some of these expenses from PGE's 2022 test year request.

Q. Are the costs that Staff isolates in Attachment 057-B direct labor costs?

A. No. The costs that Staff isolates in their work paper are not labor costs. Furthermore, these are cost categories that PGE has been including in its response to OPUC SDR No. 057 since this data request was established over 10 years ago. Prior to this adjustment, PGE has not been informed of any issues or concerns with the detail provided in this SDR through any other GRC or regulatory proceeding.

Q. Can you provide some examples of what the amounts in question pertain to?

A. Yes. Approximately $28.8 million of the amount Staff identifies in their analysis are incentive plan amounts paid to employees. These costs are clearly identified by account and PGE made a pre-filing adjustment reducing its incentives request by well over 50% of 2022 forecasted incentive costs. Another example is that, clearly identifiable by account, approximately $4.3 million of Staff's adjustment are 2020 severance payments. However, by conducting a cursory review of PGE Exhibit 401, it is clear that PGE's 2022 test year forecast does <u>not</u> include a severance expense forecast amount. Another amount Staff identifies is $2.0 million in Boardman retention costs, which have never been included in base customer prices.[9] Essentially, Staff's adjustments are reducing amounts that are not even included in this rate case. Confidential PGE Exhibit 1603 provides additional detail regarding these amounts.

Q. What are the "LL-Postretirement Service Cost" amounts Staff identifies?

A. The $1.4 million Staff proposes to adjust for "LL-Postretirement Service Cost" represent monthly payments to the Colstrip owner/operator for PGE's 20% share of the Colstrip employee pension plan. No party, including Staff, has argued that Colstrip's pension plan does not represent a prudent utility expense.

Q. Did PGE discuss and provide detail regarding non-labor and labor-related A&G expenses in its initial request?

A. Yes. PGE Exhibits 300 (Compensation) and 400 (Corporate Support) provide over 65 pages of direct testimony discussing both labor and non-labor A&G expense. Most items Staff has

[9] Boardman retention was collected through PGE Tariff Schedule 145.

identified in their adjustment are, in fact, discussed within these pieces of testimony. Included with our filing of this testimony, PGE provided eight supporting exhibits and numerous work papers that provide extensive accounting detail and support for 2018 actuals through 2022 forecast information.

Q. Does Staff discuss or provide any detail suggesting they reviewed PGE's non-labor data and testimony as filed in PGE Exhibits 300 and 400?

A. No. It appears that, rather than focusing on the substance and support for PGE's increases and decreases to non-labor A&G expense as provided in PGE's initial filing, Staff has chosen to base their $45.3 million non-labor A&G adjustment, which represents over 30% of PGE's total A&G non-labor expense forecast, on a response to a data request that did not present information in a way that they thought it should.

Q. Does AWEC rely on any of PGE's testimony, exhibits, or work papers to support their proposed non-labor adjustment?

A. No. Similar to Staff, AWEC appears to not have considered the substance and support PGE provided with its initial filing. Instead, AWEC proposes to adjust PGE's non-labor O&M by $7.5 million based solely on the fact that PGE's 2022 forecast was derived using 2020 budget information as a starting point.

Q. Does PGE's testimony regarding O&M expenses compare or justify the 2022 test year forecast against 2020 budgeted costs?

A. No. PGE's direct testimony Exhibits 200 (Revenue Requirement), 300, 400, 500 (Customer Service), 700 (Production), 800 (T&D), and all associated exhibits and work papers compare PGE's 2022 forecasted labor and non-labor O&M expenses to 2020 <u>actual</u> expenses. PGE's initial filing included hundreds of pages of testimony along with supporting exhibits and work papers comparing 2022 forecasted O&M to 2020 actual costs, not to a prior year budget. AWEC's claim that PGE has provided no evidentiary basis for its O&M increases is factually incorrect and clearly contrary to the record in this proceeding. In reading their O&M recommendation, which amounts to approximately one page of testimony, it is unclear as to whether AWEC reviewed any of the "evidentiary support" that is provided in the many exhibits and work papers provided with PGE's filing. In an apparent lack of data, analysis or argument, AWEC bases its adjustment on returning PGE's O&M forecast back to budgeted O&M amounts from 2019.

Q. Is it reasonable to base the 2022 forecast on assumptions used to develop PGE's 2019 budget?

A. No. There have been considerable changes since 2019. In addition to the COVID-19 pandemic, which AWEC highlights in their testimony, PGE has: 1) increased its vegetation management and implemented an Advanced Wildfire Risk Reduction strategy in response to increasing wildfire threats on our system; 2) implemented multiple projects as part of PGE's grid modernization efforts; 3) placed the Wheatridge Renewable Energy Farm into service; 4) retired the Boardman Coal Plant from service; and 5) constructed a new Integrated Operations Center. These are but a few of the many changes affecting and incorporated into PGE's 2022 test year forecast since 2019. All of these changes and many others are discussed throughout PGE's initial filing. Information AWEC has not taken into account. In addition, AWEC's proposal ignores the exceptional inflationary pressures that PGE has been facing since the post-COVID-19 recovery began in 2021. According to the Oregon Office of Economic Analysis December 2021 Economic and Revenue Forecast, persistent inflation is a risk, with the current Consumer Price Index (CPI) for West Region Urban Consumers projected at 4.5%

annually for 2021 and 3.9% annually for 2022.[10] According to the Bureau of Labor Statistics, for the 12-month period from October 2020 to October 2021, the CPI for All Urban Consumers has increased by 6.2 percent. This is the highest increase since November of 1990.[11] In fact, 2021 and 2022 current projections, along with 2021 current year actuals, are substantially greater than amounts assumed by PGE in the 2022 test year.

Q. How do you respond to AWEC's claim that 2022 forecast amounts, due to PGE's budgeting process, are not known and measurable?

A. AWEC's brief discussion of PGE's budgeting process to support their adjustment is inaccurate. In fact, PGE has many controls in place that govern and guide the budgeting process, and budgets are not simply escalated from one year to the next as AWEC appears to suggest. PGE's annual budget process has two distinct pieces. The capital budgeting process is discussed in PGE Exhibit 1800. The process for O&M is outlined below. PGE's Corporate Planning department is responsible for managing the overall budget process, ensuring the appropriate level of review is given, and that all corporate approvals are secured. This part of the budgeting process is initiated by the issuance of an "O&M Budget Call Memo" from PGE's Corporate Planning Department. Each department manager is then responsible for preparing the department budget, which includes providing documentation supporting cost or revenue changes from year to year and listing the key activities/plans/assumptions underlying the budget.

Q. What support do department managers receive with justifying their budget amounts?

A. The Supply Chain department is responsible for providing support to department managers in developing budget costs that consist of outside services or material needs. Supply Chain is

[10] See PGE's Exhibit 1600 work papers for the December 2021 Oregon Economic and Revenue Forecast.
[11] https://www.npr.org/2021/11/10/1054019175/inflation-surges-to-its-highest-since-1990.

responsible for the sourcing, selection, negotiation, and contract execution (contract signature) for these external costs. Supply Chain category strategies, Requests for Proposals (RFP), negotiations, and market insight help drive confidence in budget estimates and ensure compliance with the applicable policies and procedures.

Q. Who else is involved in PGE's budgeting process?

A. After department managers and the Supply Chain department have completed their review of the upcoming year's budget and have entered their initial request and supporting documentation into PGE's budgeting system, a number of approvals and iterations are necessary prior to budget approval. These include the following:

1. PGE Vice Presidents (VP) are responsible for reviewing and approving the activities and associated cost/revenue proposed in the department budgets within their functional areas. As part of this, any significant new operating projects are identified and prepared for presentation to PGE's Board of Directors (BOD).
2. Corporate Planning is responsible for consolidating all the department budgets (once reviewed and approved by the functional VP) into a fully allocated income statement and presenting the results to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) for review.
3. The CFO is responsible for the overall development of the consolidated annual budget. The CFO reviews the proposed operating activities, associated costs/revenues, variances from the prior year, consistency with the Strategic Direction, etc., and makes a recommendation to the CEO.
4. The CEO is responsible for reviewing the activities and associated costs proposed in the annual Operating Plan & Budget, ensuring they are consistent with PGE's

Strategic Direction, authorizing the annual budget, and presenting it to the BOD for final review and approval.

5. The BOD is responsible for reviewing the activities and associated costs proposed in the annual budget, ensuring they are consistent with the Strategic Direction, and providing the final authorization of the operating activities represented in the budget.

Q. Do Staff's and AWEC's proposals to PGE's non-labor O&M present any other issues when compared to PGE's 2021 budgeted and 2022 forecast?

A. Yes. An important fact both Staff's and AWEC's proposals fail to consider is that, in both our 2021 budget and 2022 forecast, PGE included significant budget reductions. In fact, these budget savings included in PGE's test year forecast exceed proposed adjustment amounts from both Staff and AWEC, who use data that do not account for these savings.

Q. What is the total O&M savings amount PGE included in the 2022 test year forecast?

A. In total, PGE included over $62 million in known and measurable O&M savings, which would not have been reflected or accounted for in either Staff's or AWEC's adjustment. These are savings in addition to amounts PGE voluntarily removed from its filing (e.g., PGE's voluntary reductions to incentives, insurance, and meals and entertainment). These savings, which amount to $39.8 million for the 2021 budget that is carried forward into 2022 and an additional $23.0 million specific to the 2022 forecast, represent committed reductions to PGE's budgeted and forecast O&M expenses.

Q. Please summarize PGE's response to Staff's and AWEC's proposed adjustments to non-labor O&M.

A. Both Staff and AWEC have failed to consider the substance of PGE's test year request and instead propose adjustments that appear largely punitive in nature. PGE has provided a substantial amount of testimony and supporting data to justify its 2022 test year forecast against 2020 actuals. A 2022 test year forecast based upon known and measurable changes that are discussed and supported throughout PGE's initial filing and that include both increases and decreases compared to 2020 amounts. In contrast, both Staff's adjustments, based on the geography of 2020 transactional data, and AWEC's adjustment, based upon returning PGE to a 2019 budget, appear to ignore all aspects of PGE's test year request, which calls into question their analysis of PGE's filing.

III. Property Insurance

Q. Please summarize AWEC's proposal regarding PGE's Property Insurance.

A. AWEC argues that because "2022 property insurance premiums are not yet known,"[12] the 2021 actual property premium amount of $9,508,350, provided by PGE in its response to AWEC Data Request (DR) No. 182,[13] should be used in place of PGE's 2022 test year forecast amount. This results in AWEC's proposed $722,649 reduction to PGE's 2022 forecasted property insurance premium of $10,230,999.

Q. What is the test year PGE uses in its filing?

A. As we state in PGE Exhibit 200, from our direct testimony, PGE's test year is calendar year 2022. In other words, we base our O&M forecast in this case on a forecast of calendar year 2022 expense.

Q. Does AWEC argue for the use of a different test year period?

A. No. AWEC does not argue for the use of a different test year period or that the use of calendar year 2022 is not representative of the period when prices for this GRC will be in effect.

Q. Is AWEC's proposal for using 2021 Property Insurance actuals as a substitute for PGE's 2022 forecasted amount appropriate?

A. No. PGE does not believe it is appropriate to use 2021 premium amounts for 2022 simply because 2022 premium amounts are unknown. The entirety of PGE's GRC request is based upon a forecasted 2022 test year. In fact, PGE's current expectation for 2022 property insurance premiums is even greater than the approximate 7.6% increase to 2021 actuals that was included in our initial filing.[14] PGE has continued to see property insurance increases

[12] AWEC/100/page 14/line 8.
[13] A copy of PGE's response to AWEC DR No. 182 is provided as PGE Exhibit 1604.
[14] PGE's current expectation for 2022 property insurance is $11.5 million, compared to the $10.2 million included within our test year forecast.

predominantly driven by premium rate increases in response to current market conditions and the 7.6% increase, compared to 2021 actuals is only slightly higher than the 6.5% compound annual growth rate in PGE's actual property insurance premiums from 2017 – 2020.[15]

Q. Please describe the market conditions leading to this increase.

A. Utility property insurers have struggled to make an underwriting profit as losses outpace premiums. Coupled with industry-wide losses, PGE has also suffered several insured property losses that remain open and active, which further compounds the expected premium increase in 2022.

Q. Based on this information is it reasonable to expect there would be no increase to PGE's property insurance for 2022?

A. No. Based on PGE's historical property insurance premium increases, current market pricing trends, PGE's growing asset base, PGE's losses, and other industry-wide losses, it would be imprudent and unreasonable to expect or assume that premiums forecasted for 2022 would remain flat and not exceed premiums paid in 2021.

[15] See Confidential PGE Exhibit 403.

IV. Other A&G Adjustments

Q. When did PGE start including Margin Net Interest and Revolver Fees in its GRCs?

A. PGE first included margin net interest and revolver fees in A&G in its 2011 GRC (Docket No. UE 215), as a result of the stipulated agreement between Staff, the Oregon Citizens' Utility Board, and the Industrial Customers of Northwest Utilities (AWEC's predecessor), that was formally adopted through Commission Order No. 10-410. PGE has since continued to include these costs in A&G in each of its subsequent GRCs: 2014 (Docket No. UE 262), 2015 (Docket No. UE 283), 2016 (Docket No. UE 294), 2018 (Docket No. UE 319), 2019 (Docket No. UE 335), and 2022 (Docket No. UE 394).

Q. Why did PGE begin including these costs within base customer prices?

A. The inclusion of these costs was and is a direct result of PGE's participation in the wholesale power markets. The power markets had evolved over time from bilateral physical trades between and among electric utilities (a predominantly physical market without independent parties) to one that incorporates a number of independent parties and is predominantly financial. While this evolution brought benefits such as more counterparties and additional liquidity, it also brought with it more explicit fees (e.g., margin net interest and revolver fees). In summary, these are standard costs incurred through the course of transacting in power markets that PGE has included in the previous six GRCs.

A. Margin Net Interest

Q. What is Margin Net Interest?

A. PGE posts or receives collateral deposits (also known as margin deposits) related to wholesale power and fuel contracts where delivery and/or settlement occurs in the future. PGE holds deposits made by counterparties with which PGE transacts (e.g., utilities, power marketers, and clearing brokers). These deposits are based on the difference in the contract price relative to the current market price, and in the case of deposits held by a clearing broker may also include a maintenance component.

Margin net interest is interest paid by PGE to trading counterparties for these deposits that are held as collateral for energy, capacity, transmission, and fuel purchase contracts, which are critical for PGE in securing economic and reliable power to meet customer load.

Q. Please summarize AWEC's proposal regarding Margin Net Interest.

A. AWEC argues that because PGE includes $114,219 of margin net interest in its revenue requirement, PGE should also include "financing benefits" associated with holding the deposited margin liability balances.[16] Specifically, AWEC proposes to include as a liability to PGE's rate base (i.e., a decrease to PGE's rate base) the 12-month 2020 average net margin liability balance, which would result in a $2,400,716 reduction to PGE's revenue requirement.

Q. How does PGE respond to AWEC's Margin Net Interest proposal?

A. Ignoring the fact that AWEC's proposed adjustment to PGE's revenue requirement is approximately 20 times greater than the expense PGE has routinely included within its last six GRCs, AWEC fails to recognize that these funds, which PGE briefly holds for energy, capacity, transmission, and fuel purchase contracts cannot be used to achieve any corresponding financing benefits. These funds must be readily available to pay back, meaning that PGE must maintain immediate liquidity and cannot use these funds for any other purpose(s). Therefore, there is no corresponding "financing benefit," that merits inclusion within PGE's rate base. Furthermore, the volatility of these monthly balances can change dramatically from one day to the next and from one month to the next.

[16] AWEC/100/page 13/lines 7-9.

Q. Please provide some examples of this volatility.

A. This extreme volatility can be demonstrated through a simple review of PGE's response to AWEC DR No. 254, Confidential Attachment 254-A.[17] If calculating the monthly balance similar to AWEC's work paper support,[18] one can easily see that the monthly balance goes from approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in January 2020, down to [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in December 2020. In fact, for the year, it goes from a monthly high of $62.6 million all the way down to a low of $4.7 million. Furthermore, if one reviews the 2021 data also provided in Attachment 254-A, the balance goes from approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in January 2021 down to a credit amount of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] for the month of September. If PGE were to propose AWEC's same methodology but replace the 2020 data provided with the 2021 data provided in Attachment 254-A, PGE would be requesting a revenue requirement <u>increase</u> of approximately $333,000.[19] This clearly demonstrates the inappropriateness of AWEC's proposal.

B. Revolver Fees

Q. What is a revolving credit facility and how does it work?

A. A revolving credit facility is a reserve of cash set aside by multiple banks for potential use by a company, usually at times when cash is inaccessible through other channels. The revolver term is the amount of time that a company has secured access to the reserve. Five years is commonly the period secured by utilities and is the term used by PGE. Each year PGE must

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[17] A copy of PGE's response to AWEC DR No. 254 is provided as Confidential PGE Exhibit 1605.
[18] As provided in the AWEC work paper "UE 394_Mullins Revenue Requirement Calculations_CONF".
[19] Confidential PGE Exhibit 1603 provides this calculation.

extend its revolver one more year in order to maintain the five-year period with all of its banks. Should PGE need cash during this time, it can borrow it under the facility. However, if PGE borrows funds under its revolving credit facility, interest would be paid on the amount borrowed at a rate as determined by the revolver agreement with its banks. Typically, this interest rate is much higher than the rate PGE would incur from borrowing cash from other sources, which is why the revolving credit facility is only used as a last resort for meeting liquidity needs.

Q. What are revolver fees?

A. Revolver fees are paid by PGE to the various banks participating in PGE's revolving credit facility for PGE to have access to the cash reserve if needed. Revolver fees include revolver extension fees, annual fees, and agent and legal fees. They do not include any interest on cash borrowed under the facility.

Q. Why is it important for PGE to have access to a revolving line of credit, for which PGE pays revolver fees?

A. There are two key reasons that a revolving credit facility is necessary. First, as mentioned above, a revolving credit facility gives PGE access to capital when all other possibilities are inaccessible. For example, when debt markets were constrained due to the COVID-19 pandemic, PGE was able to use its revolving credit facility to access cash when there was a short-term liquidity shortage in the market. It is necessary for PGE to always have access to enough liquidity to meet collateral requirements for power operations and to maintain its business.

Second, rating agencies (in PGE's case, Standard & Poor's and Moody's) take PGE's available liquidity into account when determining the credit ratings assigned to PGE. Without this revolving credit facility, which includes associated fees (e.g., revolver fees), PGE would be subject to a potential decrease in credit ratings. In fact, it is very likely that without our revolving credit facility, PGE would lose its investment-grade rating. If the credit ratings are reduced and PGE were to lose its investment-grade rating, PGE's ability to offer and sell debt or equity securities quickly to take advantage of favorable market conditions would be adversely affected, increasing PGE's the cost of debt.

Maintaining investment credit ratings supports PGE's financial ability to maintain safe and reliable service, comply with government mandates, and respond to emergencies. Natural disasters such as wildfires or ice storms occasionally require PGE to make unexpected expenditures to restore service, and to do so, PGE must maintain strong credit with its counterparties. A financially sound utility can finance at reasonable terms in all parts of the capital market cycle, not only in good times but also when capital markets are stressed, as was the case with the COVID-19 global pandemic.

Q. Is PGE aware of any investor-owned utility that does not have a revolving credit facility?

A. No. There are no investor-owned utilities that do not utilize a revolving credit facility for the reasons stated in the question above.

Q. Please summarize AWEC's proposal regarding revolver fees.

A. AWEC argues that revolver fees represent issuance costs associated with short-term debt and should be removed from revenue requirement because revenue requirement does not consider benefits associated with short-term debt issuances.[20] AWEC proposes a $1,663,564 reduction to 2022 revolver fees.

[20] AWEC 100/page 12/lines 5-7.

Q. How does PGE respond to AWEC's proposal to remove revolver fees?

A. The basis of the argument used by AWEC is factually incorrect. Revolver fees do not represent issuance costs associated with short-term debt. They are fees paid to maintain access to a five-year reserve of capital if needed. As mentioned above and as PGE stated in its response to AWEC DR No. 133 (provided as AWEC Exhibit 103), revolver fees are paid to maintain access to a five-year rolling reserve of capital, if needed.[21] While cash borrowed under the facility does have an associated interest cost, no amounts for this are forecasted and included in this GRC.

[21] A copy of PGE's response to AWEC DR No. 133 is provided as PGE Exhibit 1606.

V. IT Projects

Q. Staff asserts that PGE did not provide all information requested in OPUC DR No. 790. How does PGE respond?

A. In its opening testimony, Staff states that "the Company has not yet fully responded to Confidential Staff DR No. 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."[22]

In OPUC DR No. 790[23] Staff identified fifteen capital projects and requested detailed records such as budgets, project development, costs, bids/proposals, RFPs, justification forms, and contracts, among other things. PGE objected to this request on the basis that it was unduly burdensome, but without waiving the objection, PGE provided budgets and justification forms for all of the requested projects. Additionally, PGE provided nearly 200 files of information related to the projects in question. Finally, PGE stated in its response that several projects are Time & Material projects and do not have individual RFPs or Statement of Work, such as replacement of desktops and laptops and the deployment of our mobile application, which was performed by an internal PGE department.

PGE provided sufficient information for Staff to analyze prudency of PGE's investment, and to include recommendations in Staff's Opening Testimony. It would be procedurally inappropriate and unfounded for Staff to provide additional adjustments to IT projects in subsequent testimony.

[22] Staff/500/page 13/lines 1-4.
[23] A copy of PGE's response to OPUC DR No. 790 is provided as Confidential PGE Exhibit 1607.

Q. What issues has Staff raised in relation to PGE's IT costs?

A. Staff Raises three issues related to IT capital projects: 1) 2020 desktop/laptop replacement costs; 2) customer mobile application costs; and 3) Physical Access Control System (PACS) costs. We address these separately below.

A. Desktop/Laptop Computer Replacement

Q. Please summarize the desktop/laptop computer replacement project.

A. In its GRC rate base request, PGE included three capital projects related to the replacement of desktop/laptop computers as well as other computer accessories such as monitors, docking stations, conference room wall mounts and other hardware related to computing devices.

Q. Please summarize Staff's issue and the proposed adjustment.

A. Staff expressed concerns that project costs in 2020 were above average compared to 2018 actual, 2019 actual, and 2021 budget replacement costs. Staff notes that "[b]ecause 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 $1.93 million, a reduction of $1.65 million."[24]

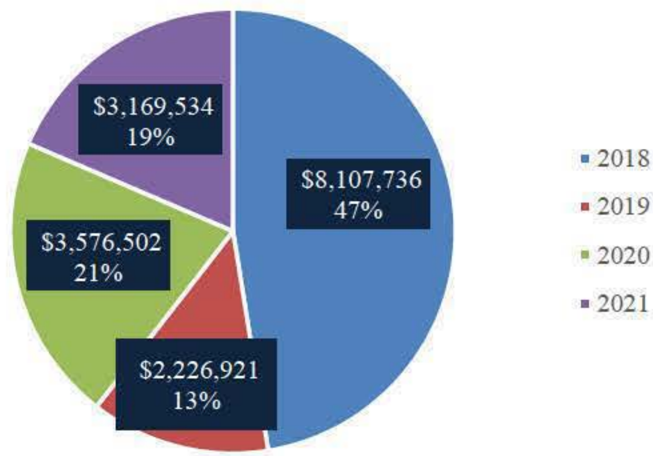
Q. Does PGE agree with Staff's analysis of desktop/laptop computer replacement costs?

A. No. Staff provided a chart of replacement costs between the years 2018 and 2021.[25] However, the costs Staff used for 2018 analysis are incorrect. While Staff references $1.83 million as the amount related to 2018 desktop/laptop replacement projects (capital project P36525 - 2018 Desktop Vintage), the full laptop/desktop replacement costs for that project, as provided in the "Budgets for all Projects" file in PGE's response to DR 790, Attachment 790-A, amounts

[24] Staff/500/page 17/lines 6-8
[25] Staff/500/page 17/Figure 1

to $8.12 million. Figure 1 below provides the corrected 2018-2021 project amounts including the full amount for 2018.

Figure 1 – Desktop Replacement Costs



As evidenced by Figure 1, 2020 costs are substantially below 2018 replacement project costs and are in line with 2018-2021 annual averages.

Q. Does PGE have other concerns regarding Staff's adjustment?

A. Yes. PGE believes it is also inappropriate to exclude 2020 computer replacement costs from the average. Costs for desktop and laptop replacement projects vary from year to year and when calculating an average, it is inappropriate to exclude one year.

Q. What would be the result of both correcting for the 2018 amounts and including 2020 amounts in Staff's analysis?

A. If simply correcting for 2018, the average increases to approximately $4.50 million, or approximately $0.92 million higher than 2020 costs. If correcting for 2018 and including 2020 within the average, the average of all year project costs is $4.27 million, or approximately $0.69 million higher than 2020 costs.

Q. Please describe why 2020 desktop/laptop replacement costs are higher than 2019 and 2021 year replacement costs?

A. Items included in the projects under consideration include printers, plotters, conference room equipment, monitors, and monitors arms in addition to the standard replacement of old laptop/desktop computers. The COVID-19 pandemic began in 2020 and resulted in employees switching to hybrid and remote work at PGE as well as nationally and globally across industries. This required upgrades to conference rooms to better allow collaboration between onsite and offsite employees. Employees who previously worked on desktop computers needed a laptop and additional monitors to work from home. Finally, every few years PGE sees a spike in replacements related to technology changes. In this case, the new Windows 10 release required the replacement of older computers that were not compatible with the new Windows 10 software. As a result, 2020 replacement costs were higher than costs in 2019 and 2021.

Q. What is your request of the Commission?

A. We request that the Commission reject Staff's proposed adjustment of $1,650,000, as PGE's computer replacement costs are completely in line with historical averages, are prudently incurred expenditures, and are partially a function of PGE's shift to hybrid and work from home models.

B. Customer Mobile Application

Q. Please summarize the customer mobile application project.

A. PGE requested recovery of three capital projects related to the customer mobile app: initial deployment of the application in 2018, and the 2020 and 2021 upgrade of the mobile application. The total cost of the mobile application replacement project is [BEGIN

CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. In the PGE mobile application, customers can pay bills, report an outage, and receive updates on outage status within the outage maps, monitor usage, and receive live and dynamic information updates from PGE, as well as other functionalities.

Q. Please summarize Staff's issue and proposed adjustment.

A. Staff conducted research to compare PGE's mobile application to the PGE customer-facing website which is mobile-enabled and stated that PGE's mobile application is duplicative of its website. However, Staff Exhibit 500 notes "Due to the fact that the Staff member is not a PGE customer, we were unable to further login and test customer-specific features." Staff attempted to compare PGE mobile application pricing to commercial application development but was unable to get a comparable price to the wide variety of mobile applications that exist on the market. Based on the customer service features available on PGE's website while using a mobile device, Staff recommended the full disallowance of [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] in costs related to the development of PGE's mobile application.

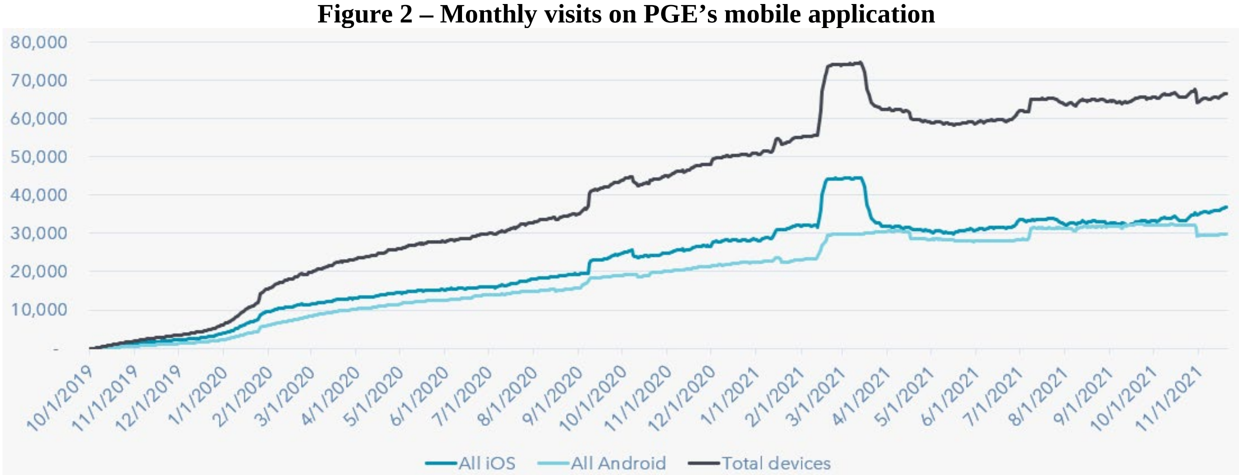
Q. Is the mobile application duplicative of the PGE website?

A. No. Although some features of the product are duplicative and it is possible to view web content on a mobile device, the content is not optimized for a mobile device. A mobile application is a more user-friendly option that provides enhanced user experience including faster interactions and access to capabilities on the mobile device like push notifications, biometric login like face or fingerprint recognition for automatic account login, and direct connections between the mobile device and other connected devices to simplify energy management.

Q. Is customer interaction with PGE's network different during an outage?

A. Yes. During an outage event, PGE can experience a significant spike in mobile visits as people turn to their mobile phones when their power is out. Figure 2 below shows the number of monthly visits on PGE's mobile application over time. The spike in use in early 2021 is due to the ice storm that affected the Pacific Northwest.

Figure 2 – Monthly visits on PGE's mobile application



Q. How does PGE compare to other utilities?

A. According to JD Power Rankings, utility customers rate mobile applications slightly higher than websites by a margin of 38 points (on a 1,000-point scale).[26] Every utility within the West Region: Large Segment list of top-ranked electric utilities, as reported by the JD Power 2019 Electric Utility Business Customer Satisfaction Survey, has a mobile application in addition to its website.[27] Additionally, of 36 utilities surveyed by Edison Electric Institute (including PGE), 18 utilities had a customer mobile application.[28]

[26] https://www.jdpower.com/business/press-releases/2019-electric-utility-business-customer-satisfaction-study.
[27] https://www.jdpower.com/business/press-releases/2020-utility-digital-experience-study.
[28] Edison Electric Institute, (2021, October 13). CEO Policy Committee on Customer Solutions Meeting Materials provided as PGE Exhibit 1701.

Q. Does PGE have evidence that customers want a mobile application?

A. Yes. In a July 2012 survey of PGE customers, 63% of respondents requested a mobile application. At the time, PGE opted to develop a mobile-friendly website to reduce the total number of platforms needing support. In the years since, customers have grown to expect a mobile application from PGE, with accompanying access to the location and messaging features of smartphones as basic requirements for high-end customer support.

Q. Please summarize your response to Staff's proposed disallowance of PGE's customer mobile application.

A. Mobile applications have become a standard offering for customer-centered businesses and the lack of a mobile application reduces the ways in which customers can engage with PGE and limits PGE's ability to provide timely information and facilitate the easiest interaction between PGE and its customers. PGE's investment in this application is a prudent utility expenditure and PGE requests that the Commission reject Staff's proposed [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] disallowance.

C. Physical Access Control System (PACS)

Q. Please summarize the PACS project.

A. The PACS project is the upgrade/replacement of existing doors/access points at PGE facilities designed to improve security. The PACS project costs include software, electronic hardware, cameras, monitoring systems, doors, and access points.

Q. Please summarize Staff's issue and proposed adjustment.

A. Staff conducted research and determined that the average cost per door ranges from $1,500 to $10,000 for a large company corporate access system.[29] PGE's project includes [BEGIN

[29] Staff 500/page 21/lines 1-2.

CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. "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]."[30]

Q. Is the PACS project related to the new Integrated Operations Center (IOC)?

A. No. In their testimony, Staff states, "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."[31] However, the PACS project does not include any cost related to the IOC. Instead, the IOC-related costs are included in project number P36501, Integrated Operations Center. PACS project costs are related to retrofitting 106 existing PGE facilities such as WTC offices, regional service centers, substations, and line centers.

Q. Does PGE have greater security needs than an average commercial/corporate facility?

A. Yes. As a provider of an essential service, PGE has greater security needs to ensure that its provision of services is not disrupted because of a security failure. Physical security measures are required by the Critical Infrastructure Protection (CIP) plan created by the North American Electric Reliability Corporation for operation of the bulk electric system in North America. CIP-006-6 R1[32] requires:

- Methods of physical access control (such as card key, special locks, security personnel or other authentication devices (e.g., biometric keypad));

[30] Staff 500/page 21/lines 12-15.
[31] Staff 500/page 21/lines 8-11.
[32] https://www.nerc.com/pa/Stand/Reliability%2520Standards/CIP-006-6.pdf.

- Methods to monitor physical access (such as alarm systems (with notification within 15 minutes of breach without authorization) for window, doors, gates, or human monitoring by security personnel); and
- Methods to log physical access (such as computerized logging, video recording or manual logging).

Q. Are costs for a commercial/corporate facility similar to the security required for a utility facility?

A. No. The physical and cyber security levels for utilities have grown due to continued threats around the efforts to control core infrastructure. Additionally, due to the stringent requirements of CIP standards, PGE implemented a completely new, enterprise-level security access control and video system. Infrastructure requirements including servers and video components, along with setting up the doors at all the facilities provided a complex and unique environment that is unlike a commercial/corporate facility that would have less complex security requirements.

Q. Please summarize PGE's response to Staff's concerns regarding the PACS project.

A. PGE's PACS project costs are not related to new facilities. Rather, these costs are specific to retrofitting existing facilities. Additionally, the facility security requirements of a utility are greater than those of a large commercial/corporate building and are therefore more expensive than the cost ranges provided by Staff. Finally, the cost of implementing PGE's Physical Access Control System is reasonable given the complex and stringent security requirements to which PGE adheres.

VI. Summary and Conclusion

Q. Please summarize your proposals regarding the issues identified by Parties.

A. We recommend the Commission reject Parties' proposals regarding the issues identified. With respect to these proposals, our responses are summarized below:

- A&G Non-Labor O&M Expenses: PGE does not accept any of the four separate adjustments to non-labor O&M. Staff's proposed adjustment to PGE's 2022 forecast based on 2020 transactions is unfounded, punitive in nature, and in many instances proposes adjustments to amounts PGE either voluntarily removed from the 2022 test year prior to filing or to adjustments Staff proposes elsewhere in their testimony. However, PGE does welcome a collaborative discussion with Staff on how best to modify the data provided in response to SDR Nos. 057 and 058 moving forward.

  AWEC's proposed adjustment incorrectly assumes that PGE's 2022 forecast was based upon 2020 budget information. PGE actually compared 2022 forecasted labor and non-labor O&M expenses to 2020 actual expenses (not a prior year budget) across its hundreds of pages of direct testimony, exhibits, and work papers. It is unclear whether AWEC analyzed or reviewed the documentation in PGE's filing.

- Property Insurance: PGE proposes no adjustment to property insurance costs. AWEC's proposal to use 2021 premium amounts because 2022 amounts are not yet known is imprudent and unreasonable, especially considering PGE's historical and forecasted property premiums, current market pricing trends, PGE's growing asset base, PGE's losses, and other industry-wide losses.

- Margin Net Interest: PGE proposes no adjustment to margin net interest. AWEC's argument is incorrectly based on the notion that PGE receives a financing benefit from holding the deposited margin balances. In fact, the margin liability balances that PGE briefly holds fluctuate dramatically within and between months, must remain readily available, and cannot be used for other purposes (e.g., to finance other activities).
- Revolver Fees: PGE does not agree with AWEC's erroneous proposal because revolver fees do not represent issuance costs associated with short-term debt. Rather, revolver fees are fees paid to the bank for PGE to have access to a revolving line of credit facility which is critical for PGE to maintain investment grade credit ratings. However, PGE does agree that it inadvertently overstated 2022 revolver fees by $177,715.
- Desktop/Laptop Computer Replacement Project: PGE proposes no adjustment to its desktop/laptop computer replacement project. Staff used an incorrect amount in its 2018 analysis and did not consider the increased 2020 expenses associated with technology changes and with equipping employees who shifted to hybrid and work from home models during the pandemic.
- Customer Mobile Application: PGE proposes no adjustment to the three capital projects related to its customer mobile application. Customers expect and increasingly use PGE's mobile application, which enables them to pay bills, report outages, receive updates on outage status, monitor usage, and receive dynamic updates, more easily. The mobile application is not duplicative of PGE's website,

is a critical resource during outages, and facilitates engagement and communication between PGE and its customers.

- Physical Access Control System (PACS): PGE proposes no adjustment to its PACS project. The PACS project is not related the IOC but to the retrofitting of 106 different existing PGE facilities. Further, the cost ranges provided by Staff are understated as PGE's (and other critical infrastructure providers) security requirements are more stringent and complex than a typical industry.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
1601C	PGE's Response to OPUC SDR No. 057
1602	PGE's Response to OPUC SDR No. 058
1603C	Detail Regarding PGE's A&G Non-Labor Expenses
1604C	PGE's Response to AWEC DR No. 182
1605C	PGE's Response to AWEC DR No. 254
1606	PGE's Response to AWEC DR 133
1607C	PGE's Response to OPUC DR No. 790

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.

Exhibits 1601-B through 1601-D
are confidential and provided only
in electronic format.
Exhibits are subject to
General Protective Order 21-206

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.

<u>Revised Response (dated September 28, 2021):</u>

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.

Exhibits 1602-B through 1602-E
are voluminous in size and
provided only in electronic format

Exhibit 1603 is confidential and
provided only in electronic format.
Exhibit is subject to
General Protective Order 21-206

October 14, 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 182
Dated September 30, 2021

Request:

Please identify each of PGE's currently effective liability insurance policies, the associated premiums, deductibles, coverages, and any other relevant information about the policies. Please also provide a policy statement for each policy.

Response:

Confidential Attachment 182-A and Attachment 182-B provide the requested information.

As of October 8, 2021, all but one line of coverage (Aircraft Hull & Liability) has been renewed for the 2021-2022 policy year. The forecast is updated throughout the course of the year as policies renew to reflect the most current year-end insurance premium forecast.

Confidential Attachment 182-A contains protected information and is subject to General Protective Order No. 21-206.

Exhibit 1604-B is confidential and
provided only in electronic format.
Exhibit is subject to
General Protective Order 21-206

PGE's Insurance Policies

Insurance Policy	Description
All Risk Property	PGE’s main All-Risk property insurance program is led by FM Global and insures PGE’s property such as power plants, substations, office buildings, etc. from “all-risks” of direct physical loss or damage (including boiler and machinery), subject to policy exclusions, caused by perils such as fire, explosion, lightning, wind, ice, hail, flood, earthquake, and certain acts of terrorism. This policy specifically excludes coverage for PGE’s transmission and distribution property as well as PGE’s renewable projects. Under this program PGE maintains coverage limits of $600 million with a $2.5 million deductible.
Renewable Property	The All-Risk property insurance program for PGE’s renewable assets is currently placed in the London market. Operational All-Risk coverage for these assets, including both wind and solar, are insured to their combined full replacement value of $1.3 billion and carry a $1 million deductible for wind assets and $0.025 million deductible for solar assets.
Director's and Officer's Insurance	Directors and Officers (“D&O”) Liability Insurance shields PGE’s directors and officers against the normal risks associated with managing the business. The insurance premiums requested in this case are reasonable expenses that are necessary to attract and maintain qualified and competent directors and officers and they provide a direct benefit to PGE’s customers. Currently PGE purchases $140 million in D&O insurance limits with $1 million deductible. No deductible applies to Side A, or individual coverage. The limits purchased are reasonable, necessary and consistent with the standard practice of the utility industry. The lack of an appropriate level of D&O insurance would make it difficult for PGE to hire qualified and competent people for positions at the director and officer level. In addition, lack of appropriate D&O limits would provide a significant motivation for our experienced directors and officers to seek employment elsewhere. Subjecting the Company to the potential of such adverse outcomes is not in the best interest of PGE’s ratepayers.
General & Auto Liability	General and Auto Liability insurance covers PGE’s legal liability from claims resulting from bodily injury or property damage arising out of PGE’s operations, including the use of company vehicles. Given PGE’s contact with its customer’s premises and the dangerous nature of its operations, this insurance is of paramount importance. PGE maintains coverage limits of $185 million with a $5 million self-insured retention.
Nuclear	PGE is required by the United States Nuclear Regulatory Commission to maintain Nuclear Liability coverage for the on-site storage of its spent fuel until such time that the radioactive materials have been removed from the Trojan site. The coverage consists of three policies: (1) The Facility Form insuring PGE’s legal responsibility for damages because of bodily injury, property damage, or covered environmental clean-up costs caused by the Nuclear Energy Hazard during the policy period and reported within ten years of the policy termination date. (2) Master Worker insuring PGE’s legal obligation to pay as damages because of bodily injury sustained by a “worker” and caused by the nuclear energy hazard. “Worker” refers to a person who is or was engaged in nuclear related employment; (3) Suppliers and Transporters covering incidents caused by radioactive waste materials stored either temporarily or permanently at off-site locations not owned/operated by the insured.
Fiduciary	Fiduciary Liability insurance provides protection for officers and employees for both breach of fiduciary duties and other wrongful acts in the administration of employee benefits programs. This program is made up of total limits of $50 million with a $0.25 million self-insured retention.
Aviation (Helicopter)	This policy insures the helicopter’s hull value from physical damage and provides $20 million of liability coverage in operating the aircrafts during PGE’s aerial patrol operations.
Aviation (Unmanned Aircraft Systems)	This policy provides $5 million of liability coverage for operating Unmanned Aircraft Systems (also known as 'Drones') while conducting aerial patrols and inspections.
Cyber	The policy has several insuring agreements, providing coverage for: (1) damages and claims expenses due to theft, loss or unauthorized disclosure of personally identifiable non-public information or third party corporate information, (2) costs incurred to comply with a breach notification law, and (3) claims expenses and penalties in the form of a regulatory proceeding resulting from the violation of a privacy law such as HIPPA or FTC. PGE purchases a limit of $30 million with a $1 million self-insured retention.
Fidelity & Crime	Insures losses incurred by PGE or its employee benefit plans as a result of the dishonest acts of employees, including embezzlement, forgery or the theft of money or securities. The policy has a $10 million limit and $0.5 million deductible. This coverage is typically excluded under most All-Risk Property policies and must therefore be purchased under separate cover.
Excess Workers' Compensation	The State of Oregon requires PGE to maintain Workers' Compensation coverage to protect itself from catastrophic losses to employees arising out of and in the course of employment. This coverage sits above PGE's self-insured Workers' Compensation program and is subject to a $2 million self-insured retention.
Sabotage & Terrorism	Insures buildings and contents against physical loss or physical damage. Insures damages and claims expenses that the Company may become legally liable to pay for bodily injury, property damage and/or defense costs caused by an Act or series of Acts of Terrorism and/or Sabotage. PGE maintains coverage limits of $800 million for property and $200 million for liability subject to a $0.25 million deductible.
Surety Bonds	In the course of doing business PGE must procure and maintain a number of Surety bonds throughout the year. These bonds allow PGE to do work for various state and city governments and agencies and are a requirement for maintaining a form of collateral for self insuring PGE's Workers’ Compensation obligations.

October 19, 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 254
Dated October 7, 2021

Request:

Reference PGE's Response to AWEC Data Request 132: Please provide detail of the monthly deposited net margin liability balances identified in the referenced request on a monthly basis over the period January 2020 through September 2021 (or the most recent month available).

Response:

Confidential Attachment 254-A provides the requested information.

Confidential Attachment 254-A contains protected information and is subject to General Protective Order No. 21-206.

Exhibit 1605-B is confidential
and provided only in electronic
format. Exhibit is subject to
General Protective Order 21-206

October 5, 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 133
Dated September 21, 2021

Request:

Reference PGE's response to AWEC Data Request 55: Please provide an explanation for the amounts identified as Revolver Fees in the amount of $1,663,564 and provide transaction data from 2020 supporting the historical amounts.

Response:

Revolver Fees are fees paid to the bank for PGE to have access to a revolving line of credit facility. Revolver fees include Revolver Extension Fees, Annual Fees, and agent and legal fees. The line of credit is used to ensure that PGE has access to adequate short-term liquidity.

Attachment 133-A provides transaction data to support $1,294,012.01 of Revolver Fees in 2020. Note that this amount varies from the $1,625,526 found in PGE Exhibit 400 work paper "Corp Supp Workpaper FINAL_Errata" tab "Adjustments" because PGE inadvertently included additional Extension Fee amounts in the work paper. This inadvertent inclusion is also applied to 2021 and 2022 Revolver Fee amounts. The correct amounts for 2021 and 2022 are $1,488,553 (not $1,628,974) and $1,485,849 (not $1,663,564).

Exhibit 1606-B is voluminous in size and provided only in electronic format

Exhibits 1607-A and 1607-B are confidential and provided only in electronic format.
Exhibits are subject to General Protective Order 21-206

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Customer Service

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Larry Bekkedahl
John McFarland

December 2, 2021

Table of Contents

I. Introduction

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

A. My name is Larry Bekkedahl. I am Senior Vice President of Advanced Energy Delivery. My name is John McFarland. I am Vice President and Chief Customer Officer. Our qualifications were previously provided in PGE Exhibit 500.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address the issues and proposed adjustments raised by the Staff of the Public Utility Commission of Oregon (OPUC Staff or Staff), and the Oregon Citizens' Utility Board (CUB), (collectively, Parties) with respect to PGE's 2022 test year forecast regarding customer service costs, Fee Free Bank Card (FFBC) Program and Transportation Electrification costs.

Q. How is your testimony organized?

A. In Section II, we respond to Staff's proposed adjustment to certain Customer Service operations and maintenance (O&M), non-labor costs. In Section III we discuss the proposed adjustments related to the FFBC Program including adoption rates and payment options. Section IV provides information related to Transportation Electrification including approved capital costs, PGE fleet electrification, O&M budget, and Electric Island. Finally we provide concluding remarks in Section V.

II. Customer Service O&M

Q. Please summarize Staff's proposals regarding non-labor Customer Service costs.

A. Staff discusses several components of PGE's Customer Service Costs which we summarize as follows:

- Customer Account expenses
- Advertising expenses
- Customer Service expenses
- FFBC Expenses
- Transportation Electrification (TE) costs

Q. Does Staff make any proposals regarding Customer Account expenses?

A. No. These expenses relate to Federal Energy Regulatory Commission (FERC) accounts 902, 903, 905. Staff states that they did not find any issue with PGE's filed costs.[1]

Q. Does Staff propose any adjustments to PGE's advertising expenses?

A. No. These expenses relate to FERC account 909. Staff concluded that "[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."[2]

Q. What adjustments does Staff propose regarding Customer Service Costs?

A. Staff proposes to reduce PGE's non-labor forecast in FERC account 908 by $3.7 million consisting of: 1) a $0.9 million reduction related to Brand/Marketing/Communications; 2) a $0.9 million reduction related to the FFBC-related expenses; and 3) a $1.9 million reduction

[1] Staff/300, Cohen/28
[2] Staff/300, Cohen/34

to TE-related expenses. In addition, Staff proposes an $8.9 million reduction to TE-related capital.

Q. Do you agree with Staff's proposals?

A. No. In total, PGE includes a $2.7 million increase in the general rate case to account 908 non-labor expenses from 2020 actuals to the 2022 forecast. Staff's proposed adjustments exceed the entire increase proposed by PGE in account 908 non-labor expenses by $1.0 million, which is a proportionately significant amount. All other Customer Service costs are considered reasonable and prudent. In reply, we first address Staff's $0.9 million reduction related to Brand/Marketing/Communications, and then we discuss the FFBC and TE adjustments in the following two sections.

Q. Please summarize how Staff developed their proposed reduction related to Brand/Marketing/Communications.

A. First, Staff notes that "[in] a review of historical budgets versus actuals, Staff found that the Company consistently over-projected O&M/NL expenses. 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."[3] Staff then observes that "[c]osts 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."[4] Based on this finding, Staff proposes to "Reduce expenses allocated to Department

[3] Staff/400, Scala/3
[4] Staff/400, Scala/3

ID 915: Brand/Marketing/Communication by $889,043 to revise 2022 Test Year expenses to the 2018-2020 three-year average of actual costs."[5]

Q. Do you agree with this analysis and its conclusion?

A. No. We believe that Staff has taken an overly narrow view of the costs and activities that are included in account 908 and that the 2022 forecast is reasonable for account 908 in general and for Brand/Marketing/Communications in particular.

Q. How can you demonstrate this?

A. We do so first by looking more closely at the budget to actual variance. To evaluate this properly, we believe that all account 908 costs need to be considered for a more holistic approach.

Q. Why do you believe a more holistic approach is necessary?

A. Account 908 encompasses a rapidly changing and expanding sphere of activities and responsibilities that are not expressly called out in the account's definition. This issue is exemplified by the fact that Staff is not convinced that certain PGE costs are properly charged to account 908: "Staff does not see an obvious linkage between the allocated costs and the Code of Federal Regulations description of Account 908"[6] (i.e., certain marketing and TE-related expenses). To address this we note that the current definition of Account 908 specifies "[t]his account shall include the cost of labor, materials used and expenses incurred in providing instructions or assistance to customers, the object of which is to

[5] Staff/400, Scala/8
[6] Staff/400, Scala/7-8

encourage safe, efficient and economical use of the utility's service."[7] The definition further specifies:

> Labor:
> 1. Direct supervision of department.
> 2. Processing customer inquiries relating to the proper use of electric equipment, the replacement of such equipment and information related to such equipment.
> 3. Advice directed to customers as to how they may achieve the most efficient and safest use of electric equipment.
> 4. Demonstrations, exhibits, lectures, and other programs designed to instruct customers in the safe, economical or efficient use of electric service, and/or oriented toward conservation of energy.
> 5. Engineering and technical advice to customers, the object of which is to promote safe, efficient and economical use of the utility's service.
>
> Materials and Expenses:
> 6. Supplies and expenses pertaining to demonstrations, exhibits, lectures, and other programs.
> 7. Loss in value on equipment and appliances used for customer assistance programs.
> 8 Office supplies and expenses.
> 9. Transportation, meals, and incidental expenses.[8]

The "encouragement of safe, efficient, and economical use of the utility's service" does not provide a precise guide to what activities are covered and is not intended to be prescriptive. However, we can see that these activities have clearly expanded over time from energy efficiency, to demand response, and more recently TE and energy storage as technology has evolved and Oregon public policy has imposed significant requirements on utilities for carbon reductions through a variety of means. In summary, account 908 in 2022 entails a much greater variety of costs and activities than prior years and PGE is charging those costs properly, especially since other account definitions do not include such costs.

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[7] Uniform System of Accounts Prescribed For Public Utilities And Licensees Subject To The Provisions Of The Federal Power Act, Account 908, Customer assistance expenses.
[8] Ibid.

Q. Staff raises specific issues with PGE's Brand/Marketing/Communications costs within account 908. Can you give some examples of why these costs are appropriate?

A. Yes. To promote safe, efficient, and economical use of electricity, PGE engages with customers to advance the use of connected thermostats and water heaters as well as grid connected battery storage systems. We encourage customers to be active participants in the electric grid, and to make electricity more affordable by participation in demand response pilots and replacement of old appliances with new energy efficient appliances. In addition, our customers have higher expectations for communications during outage events as well as other state emergencies. In the last few years, PGE has increased communications related to the COVID-19, the ice storm, and wildfire emergencies. We believe that events like this will continue to occur in our service territory and we are, and should be, prepared to respond and provide information to our customers.

Q. What is your more holistic approach and what are the results?

A. Our approach is to view all the incurred customer service costs in account 908 and not just limit the analysis to non-labor. This approach is necessary because not only are PGE's account 908 activities expanding and changing to keep up with evolving technology, expanding requirements and customer expectations, but as we pursue these activities, we need to apply the most appropriate resources (i.e., PGE labor, contract labor, and non-labor, including outside services) to perform them, which can vary from the time a budget is established to when the actual work is performed. Based on this approach, Table 1 below, provides a more complete comparison of PGE's budget to actual comparison for 2018 through 2020.

Table 1
Account 908, PGE Actuals Over or (Under) Budget*

Category	2018	2019	2020
Labor	(65,463)	1,861,989	762,915
Contract Labor	862,401	(465,528)	13,203
Non-Labor	(1,172,535)	(1,862,528)	(151,383)
Total Actuals Over (Under) Budget	(375,598)	(466,067)	624,736
Three-Year Average Over (Under)			(72,310)

** Incurred cost, not including labor loadings or Information Technology costs as these are addressed under Total Compensation and Corporate Support testimonies.*

Q. What are your conclusions from this result?

A. Based on a review of non-labor costs only, Staff observes that PGE's actual account 908 costs are consistently and significantly under budget. From this conclusion, they then calculate an adjustment to PGE's Brand/Marketing/Communications department based on the 2018-2020 three-year average of actual costs. Based on the complexity of costs and activities covered by account 908, however, a more complete comparison shows that PGE's budget-to-actual differences can vary significantly from year to year but that over the period in question, PGE's average under-budget amount is quite minimal.

Q. What is your request of the Commission?

A. We request that the Commission reject Staff's proposal to decrease the Brand/Marketing/Communications department budget by approximately $0.9 million. PGE manages its costs to provide efficient and effective communication services to address increasingly complex and expanding requirements and customer expectations such that the 2022 test year forecast for account 908 is prudent and reasonable. Finally, PGE properly books expenses to FERC Account 908 and we welcome Staff evaluating this issue further.

III. Fee Free Bank Card and Payment Options

A. Non-Residential FFBC Program

Q. Please summarize PGE's proposal regarding its FFBC program.

A. As stated in PGE Exhibit 500, our 2022 forecast for the FFBC program reflects: 1) the increased use of the residential program; and 2) PGE's proposal to allow businesses (primarily our Schedule 32 customers) to participate in the FFBC option similar to residential customers. These proposals are forecasted to increase the cost of the FFBC program by approximately $1.6 million in 2022 compared to 2020 actual costs.

Q. Does Staff agree with your proposal?

A. Staff accepts the increase in the residential FFBC program by noting that: 1) "Staff finds it reasonable for the Company to assume customers will continue to adopt bank card payment options at an increasing rate";[9] and 2) "Staff does not recommend any changes to the residential program."[10] Staff, however, does not accept the full increase in the non-residential program and proposes restrictions on its use.

Q. What issues does Staff raise regarding the non-residential program?

A. Because the non-residential program did not exist until recently, "Staff was unable to compare historical deltas between projected nonresidential transactions and actual nonresidential transactions."[11] To address this, Staff reviewed PGE's prior experience with residential adoption rates of FFBC usage and concluded that PGE's forecasted non-residential adoption rates are unreasonably high and proposed to limit the rate to 3%.

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[9] Staff/400, Scala/31
[10] Staff/400, Scala/32
[11] Staff/400, Scala/32

Additionally, Staff proposed to limit non-residential FFBC to Schedule 32 customers only and limit the payment to $1,500 per payment cycle. In their argument, Staff states that this will prevent people from making multiple payments to circumvent the existing dollar limit on the FFBC payment. These recommendations would reduce PGE's 2022 nonresidential FFBC forecast by approximately $0.9 million

Q. Do you agree with Staff's proposal to limit the forecast assumption to a 3% participation level?

A. No. Historically, adoption rates were less than 2% between January 2017 and March 2020 but this is related to residential use only. From then through April 2021, with the addition of non-residential use, however, the participation rate was 9.5%. Even more striking is that from January 2021 to September 2021, the non-residential adoption rate was 13.5%, which is higher than the forecasted adoption rate of 5% month-over-month proposed for the 2022 test year. Ultimately, digital payment adoption continues to grow faster than expected, for both residential and commercial customers.

Q. What is PGE's response to limit non-residential payment amount to $1,500 per payment cycle and limit the program to Schedule 32?

A. Card issuer rules specify that PGE cannot offer different payment options to business customers based on their basic service rate schedule but do allow transaction limits. Therefore, PGE set the limit of FFBC for all non-residential customers at $5,000 per account based on existing payment data for Schedule 32 customers. By applying Staff's $1,500 payment limit, customers with a bill over $1,500 could pay the first $1,500 by FFBC, but then would have to pay the rest of the bill by other means such as a check payment, negating the purpose of offering the program. However, limiting the non-residential FFBC program to only Schedule 32 customers is not permitted by the card issuer rules.

Q. What specifically is PGE's proposal for a non-residential FFBC program?

A. PGE proposes that the FFBC program be made available to all customer classes with existing transaction limits. However, to properly address cost-causation, PGE proposes to allocate FFBC costs to each customer class based on how much cost that class incurs. This would ensure that customers in Schedule 32, for example, will be assessed only for the fees incurred by that class and other classes will be allocated costs based on FFBC costs associated with their specific schedule. Please see Exhibit 2200 for the proposed FFBC cost recovery allocation.

Q. Does your proposal limit FFBC program use among non-residential customers?

A. Yes. The non-residential FFBC program is designed to primarily benefit small commercial customers that pay bills similar to residential customers. Although some larger customers will be able to benefit from this program, those customer classes will be assessed the fees for their FFBC use. In summary, the $5,000 transaction limit will restrict usage but many large non-residential customers with large electricity bills typically pay by a check or a wire transfer and not debit or credit cards.

Q. What would happen if the Commission were to approve Staff's proposal to limit the non-residential FFBC program to Schedule 32 customers only?

A. As noted above: 1) PGE cannot offer different payment options to business customers based on their basic service rate schedule; and 2) we plan to appropriately charge each customer class based on how much FFBC cost that class incurs. Therefore, if Staff's Schedule 32 limit were imposed, then there are two possible outcomes:

- PGE would have to terminate the non-residential FFBC program because we cannot charge bank card fees to one set of non-residential customers and have no fees for another set of non-residential customers; or
- PGE could hypothetically allow all non-residential customers to have the FFBC option but have shareholders absorb the cost of non-Schedule 32 customer card usage. Taking this outcome to its logical conclusion, then PGE could not apply the appropriate costs to non-Schedule 32 rate schedules. If so, non-Schedule 32 customers would receive the FFBC service free while Schedule 32 customers would have to pay for their class's use of it in base rates. In other words, this outcome would result in discriminatory treatment among PGE's customers.

Q. Did Staff raise any other issues regarding PGE's offering the non-residential payment option?

A. Yes. Staff takes exception to the fact that PGE did not notify them at least forty-five days before launching the FFBC program to commercial customers in accordance with Commission Order No. 15-356.

Q. Did PGE fail to give Staff at least forty-five days notice?

A. Not by design. Due to the sudden urgency of the COVID-19 pandemic and along with all the other measures being implemented to assist customers, PGE temporarily waived the debit and credit card transaction costs for all non-residential customers on April 7, 2020. At that time, it was not intended to be an expansion of the program but rather a temporary response to the COVID emergency (which required many urgent changes to the way PGE interacted with customers) to provide options for business customers to pay remotely. For example, many businesses did not have employees onsite which limited their ability to prepare checks to mail to PGE, which was their only fee-free option at the time. Many businesses including schools and government agencies are required to choose the least cost payment method, and were struggling with ways to make payments as they had to choose a check or in person method of payment. PGE's decision required fast action to remove barriers for these customers to pay their bills

PGE contacted OPUC's Energy Rates, Finance and Audits Administrator in March 2020, via phone, before expanding FFBC to non-residential customers. As the COVID-19 lockdown continued for many months, PGE continued the non-residential FFBC option, giving customers an easier way to do business with PGE and have come to rely on this program offering.

Q. Staff proposes that PGE notify the Commission of program changes before they are implemented. Does PGE agree?

A. Yes. PGE agrees to notify the Commission forty-five days in advance of any future changes to the FFBC program. PGE is open to a discussion on the manner of a reasonable notification and expects that the pivot in response to COVID-19 will factor in that discussion.

Q. Do you have any final comments regarding the FFBC program's costs?

A. Yes. In support of the reasonableness of PGE's 2022 forecast, we note that: 1) the FFBC costs are recorded in FERC account 903, which is in Customer Account expenses; and 2) Staff Exhibit 300 did not find any issue with PGE's filed Customer Account costs.

Q. What is your request of the Commission regarding the FFBC option?

A. We request that the Commission reject Staff's proposal to use a 3% adoption rate for the 2022 forecast since the 2021 adoption rate is already significantly greater than both this rate and the 5% rate PGE had forecasted. Additionally, we request that Commission reject Staff's proposal to limit the program to Schedule 32 customers and limit the payment per billing cycle to $1,500. Instead, we request that the Commission accept PGE's proposal to keep the current limit at $5,000 and allow all non-residential customers to use the FFBC program. Finally, we request that the Commission accept PGE's proposal to allocate FFBC costs of each customer class to that customer class as discussed above and in PGE Exhibit 2200.

B. Payment Options and Amazon Pay

Q. Please summarize options customers have to pay their bills.

A. Currently, customers can pay their bills on the PGE website, through PGE's mobile application, through an automated phone system, face-to-face with CheckFree Pay locations and Western Union, and over the phone with a PGE Customer Service Advisor. Additionally, PGE added the ability to pay bills through PayPal and Amazon Pay on June 30, 2021 and will be expanding to include Google Pay and Apple Pay in 2022.

Q. Why is PGE adding more customer payment options?

A. Digital wallets such as PayPal and Amazon Pay are beneficial to customers as they store personal banking information and frequently use smart phone biometric information to unlock the wallet. Before the digital wallets, customers provided debit/credit card or automated clearing house (ACH) information to every website where a transaction occurred. Allowing every website to have access to personal debit/credit card can increase risk as different sites have varying levels of cybersecurity protections. As a result, digital wallets became more popular since they allow customers to make payments without providing debit/credit card or ACH information to the individual vendors. Perhaps in recognition of the benefits of added security, the ability to pay with a digital wallet has been on the rise across many utilities. According to Edison Electric Institute, out of 36 utilities surveyed, ten utilities provided customers the option to pay with a digital wallet.[12]

Q. Do any Parties address PGE's addition of these payment options?

A. Yes. CUB contends that PGE did not meet the burden of proof to justify why it should offer Amazon Pay as an option to customers. Additionally, the fee structure for Amazon Pay is different than for other payment methods. A debit or credit card payment via PayPal, Apple Pay and Google Pay have a per unit transaction cost of **[START CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per residential customer bill. Whereas Amazon Pay has a transaction cost of **[START CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. CUB states that PGE has an obligation to minimize transaction costs for customers and **[START CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Therefore, CUB proposes that PGE no longer offer Amazon Pay as a payment option or renegotiate the payment processing transaction cost with Amazon.

Q. How do you respond?

A. Because the fee structure is not the same for the Amazon Pay compared to the other digital wallets, it is not a one-to-one comparison of transaction fees. Residential bills are usually smaller compared to non-residential bills. When multiplying residential bills by the transaction fee percentage, the average cost per transaction for a residential bill is **[START CONFIDENTIAL]** [redacted] **[END**

[12] Exhibit 1701 - Edison Electric Institute, (2021, October 13). CEO Policy Committee on Customer Solutions Meeting (Virtual).

CONFIDENTIAL] than credit and debit card payments in other digital wallets. Additionally, Amazon Pay is used infrequently by our customers and PGE estimates the fees for this service to total less than $2,000 per year.

Q. What is your request of the Commission?

A**.** We request that the Commission reject CUB's proposal to eliminate the Amazon pay option. Offering this option to our customers provides a convenience for customers with Amazon Pay wallets, and because this option is used by customers infrequently the overall impact on the FFBC is minimal. As a result, we should continue to provide this payment option for the customers that use it.

IV. Transportation Electrification

Q. What issues have Parties raised in relation to PGE's TE costs?

A. Staff raises five issues related to TE costs: 1) capital costs associated with PGE's TE pilots; 2) capital costs associated with PGE's fleet electrification; 3) capital costs associated with TE-related line extension allowances; 4) capital costs associated with Electric Island; and 5) O&M costs supporting PGE's TE capital. We address these separately below.

A. Capital Costs associated with TE Pilots

Q. Please summarize Staff's recommendation regarding the capital costs associated with PGE's TE pilots.

A. Staff notes that PGE is seeking recovery of approximately $3.4 million in capital expenditures related to the TriMet and the Electric Avenue Network Pilots and that most of these expenditures were prudently incurred.[13] Staff, however, states that PGE overspent the TriMet Pilot by $5 thousand and Electric Avenue Network Pilot by $362 thousand, based on maximum allowable capital costs established by Commission Order 19-385 (Docket UM 1811). Consequently, Staff recommends that $367 thousand be removed from PGE's rate base.

Q. Please describe what costs the Commission included within "maximum allowable costs" in Order No. 19-385.

A. Commission Order No. 19-385 states: "Maximum allowable costs are composed of direct O&M costs and overnight capital costs from the pilot. Indirect costs such as interest on

[13] Staff/1700, page 11, lines 8-10.

expenses and capital carrying costs (e.g., interest during the construction period, property taxes, income taxes, salvage, return requirements) related to the overnight capital costs, franchise fees, OPUC fees, and uncollectibles are not included in the maximum allowable costs."[14] A footnote to this citation states that "The Stipulating Parties acknowledge that de minimis 'indirect' costs like those described in paragraph 10 have not been included in the maximum allowable cost caps in Table 1 due to the difficulty in calculating them at this point in time. Such indirect costs may be recoverable in a future ratemaking proceeding but are subject to review for reasonableness and final Commission determination."[15]

Q. How are you defining "overnight capital costs" as specified in Order 19-385?

A. We define overnight capital costs as the direct, incurred, capital costs of the pilots. In PGE's response to OPUC Data Request No. 746,[16] we provided details related to the pilots with specific cost elements. The direct, incurred, capital costs of these projects sum to $3.02 million, which is below the established maximum allowable costs in Commission Order 19-385

Q. Please describe what PGE considers indirect capital costs associated with the TriMet and Electric Avenue Network Pilots.

A. We define the indirect costs as those representing overhead and allocated costs, which include labor loadings, information technology services, vehicle services, and rents. Table 2 below and PGE Exhibit 1703 provide more details on the project.

[14] Oregon Public Utility Commission Order No. 19-385, Appendix A, page 4.
[15] Ibid.
[16] A copy of PGE's response to OPUC Data Request No. 746 is provided as Exhibit 1702.

Table 2
Capital Costs for Electric Avenue and TriMet Pilots

Incurred	**$3,018,255**
UM 1811 - Electric Avenue	$2,390,130
UM 1811 - TriMet	$628,125
Loadings and Allocations	**$357,248**
UM 1811 - Electric Avenue	$356,850
UM 1811 - TriMet	$398
AFUDC	**$17,299**
UM 1811 - Electric Avenue	$15,397
UM 1811 - TriMet	$1,902
Grand Total	**$3,392,803**

Q. What are loadings and allocations and why does PGE add them to capital projects?

A. Labor loadings represent labor-related costs such as employee benefits, pension costs, incentives, payroll taxes, employee support, paid time off, and where applicable, injuries and damages. Other indirect costs include service provider allocations (e.g., information technology support) and construction overhead allocations. The loadings and allocations effectively move costs from certain sections of the income statement to the balance sheet and correspond with accepted FERC accounting.

Q. What is your request of the Commission?

A. Because Commission Order No. 19-385 states that maximum allowable costs do <u>not</u> include indirect costs, we request that the Commission allow the $367 thousand in expenditures for the TriMet, and Electric Avenue pilots, and that they be included in rate base.

B. PGE Fleet Electrification

Q. Please summarize Staff's concerns regarding inclusion of PGE Fleet Electrification charging infrastructure costs in rate base.

A. Staff recommends the Commission permanently remove from rate base approximately $6.9 million in capital expenditures related to PGE's new fleet charging sites. Staff argues that electric vehicles (EVs) purchased for PGE fleet do not require a buildout of new charging infrastructure. Specifically, Staff questions the reasonableness of the fleet charging facilities given the 200 ports for workplace charging that PGE will have in place in 2022 at various company facilities, which they say are not used at night and could be utilized for fleet charging (Staff separately recommends removing $330 thousand in O&M costs for the fleet charging sites as part of a larger TE O&M adjustment described in more detail below). Staff does find PGE's capital expenditures on specifically identified EV purchases to be prudent. Staff further notes that PGE has not filed a TE program application for the electrification of its own fleet under Commission Division 87 rules. Staff's analysis of PGE's fleet electrification expenditures, however, does not rely on the lack of a program filing, but instead rests on whether this was an investment a reasonable person would make risking the firm's own capital in a competitive market.

Q. Do you agree with Staff's recommendations?

A. No. PGE's fleet electrification costs are reasonable and prudent given the recent trends in electrification across all industries and PGE's alignment with the state's goals of reducing GHG emissions.

Q. Please elaborate on recent trends in electrification across all industries.

A. Companies across all industries, including electric utilities, have ambitious fleet electrification goals. For example: Amazon has committed to 100,000 electric delivery vehicles by 2030;[17] Duke Energy has pledged to electrify 100% of its light-duty vehicle fleet and transition 50% of its medium-duty, heavy-duty and off-road fleet to zero-carbon

[17] https://www.aboutamazon.com/news/sustainability/go-behind-the-scenes-as-amazon-develops-a-new-electric-vehicle

alternatives by 2030;[18] Southern California Edison has pledged to electrify their fleet's passenger vehicles and small-to-midsize SUVs by 2030;[19] and Xcel Energy has pledged to electrify all of their light-duty fleet vehicles by 2030.[20] Investments to electrify fleet vehicles, and preparations to install infrastructure to support electric fleet vehicles, are common both within and outside of the utility industry.

Q. Do you believe that PGE's fleet electrification plan is subject to Division 87 rules as a TE program?

A. No. We disagree with an interpretation of Division 87 requirements that a utility's internal fleet conversion program be considered a TE program under the rules. Electrification of PGE's fleet is not a broad-based, customer-focused initiative to spur development of TE marketplace in Oregon. Purchases of EV fleet are part of normal depreciation and replacement of light duty vehicles and replacement would have occurred regardless of the electrification plan. In this context, PGE is a market participant, not a market driver. In addition, Staff's narrow interpretation fails to account for the policy context that motivates PGE to electrify its fleet – most notably Governor Brown's Executive Order (EO) 20-04 regarding GHG emissions reductions.

Q. How does PGE's fleet electrification plan support the GHG emissions reduction goals in EO 20-04?

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[18]https://news.duke-energy.com/releases/duke-energy-advances-climate-strategy-with-aggressive-pledge-to-electrify-vehicle-fleet-by-2030
[19]https://energized.edison.com/stories/sce-announces-2030-goals-for-electrifying-its-vehicle-fleet
[20]https://dailyenergyinsider.com/news/26714-xcel-energy-pushes-electric-vehicles-for-fleet-pledging-20-percent-conversion-by-2030/

A. EO 20-04 establishes "science-based GHG reduction goals."[21] The executive order also directs the Department of Administrative Services to plan for procuring zero emission vehicles and develop a model zero emission vehicle procurement program that can be adopted by local governments (some of which are PGE customers). Additionally, House Bill (HB) 2027 (2021) provides for state agency light duty vehicle purchases to be zero emission vehicles starting in 2025. Although the executive order does not specifically direct utilities to invest in electrification of their own fleets, PGE's investment in electrification of its fleet aligns with the state's goals of reducing GHG emissions. PGE estimates that our fleet electrification plans will reduce greenhouse gas emissions by 6.8 million pounds of CO_2-equivalent over the next 10 years.[22]

Q. Staff is critical of the number of EV charging ports to support PGE's fleet. What future infrastructure is PGE's fleet electrification investment designed to support?

A. PGE's fleet electrification investment provides the make-ready infrastructure necessary to enable 245 Level 2 and 119 direct current (DC) fast charging ports across five locations, helping to support PGE efforts to electrify all light, medium, and heavy-duty vehicles by 2040 to meet our corporate goals. Make-ready infrastructure includes new electrical service, distribution equipment, underground electrical pathway, and civil infrastructure required to support the installation of electric vehicle supply equipment (EVSE). The completed make-ready infrastructure will enable PGE to install EVSE over time as electric vehicles are

[21] E.O. 20-04, page 8. https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf
[22] A copy of PGE's response to OPUC Data Request No. 150, Attachment E is provided as Exhibit 1704C. The information is provided in Tab "Analysis", Cell "BL26".

deployed. Detailed information on the deployment forecast was provided in PGE's response to OPUC Data Request No. 932.[23]

Q. Staff notes that the infrastructure investment goes beyond supporting the current number of EVs in PGE's fleet. Would a smaller investment in fleet electrification make-ready infrastructure now be more cost-effective for PGE's customers?

A. No. Piecemeal construction of make-ready infrastructure at locations where PGE conducts 24-hour business operations, including line crew centers and service centers, would be more costly and highly disruptive. The installation of make-ready infrastructure requires extensive civil and electrical work, including trenching, boring, and other activities that disrupt areas where PGE fleet vehicles park and operate. Such construction activities also require areas for the staging of excavation and earth-moving equipment and materials, further disrupting PGE's daily operations.

Construction costs would also increase if make-ready infrastructure installation work were conducted in phases. PGE customers would end up paying for multiple mobilizations and demobilizations of construction crews, permitting processes, and demolition and restoration of hard- and softscape surfaces.

PGE's decision to install make-ready infrastructure to support its long-term fleet needs now, and install EVSE piecemeal as EVs are procured, represents the least costly, least disruptive approach, and avoids spending on unnecessary equipment.[24] Make-ready infrastructure, including transformers, switchboards, panelboards, conduits, concrete equipment pads, and bollards, are generally robust, technically mature, and have multi-

[23] A copy of PGE's response to OPUC Data Request No. 932 is provided as Exhibit 1705.
[24] This is also the recommendation that PGE gives to Fleet Partner customers since it is the most cost-effective option for fleet electrification.

decade expected operating lives, reducing the likelihood that PGE's initial investment will become outdated as charging technology evolves. Quarterly investments spread out over multiple years in Level 2 and DC fast charging equipment enables PGE to only place equipment into service when it is needed and enable equipment selections to change as technology advances.

Q. Is PGE's current workplace charging infrastructure adequate to support the company's fleet electrification in the near term?

A. No. PGE's current workplace charging infrastructure is designed for employee vehicle charging only and does not meet the needs of PGE's fleet vehicles. Even if the current workplace chargers were used to service PGE fleet vehicles, PGE does not have EVSEs at necessary locations, do not meet equipment specifications to charge PGE's fleet, and lack the cyber security capabilities PGE's electric fleet will require.

PGE's fleet electrification plans start with the electrification of two vehicle classes: light-duty passenger battery electric vehicles; and medium- and heavy-duty vehicles equipped with idle mitigation systems (vehicles capable of running auxiliary loads from an onboard battery while parked at a job site). Many of these larger vehicles require charging from conventional 120V, alternating current (AC) receptacles, cannot fit into the parking stalls created for light duty vehicles, and do not utilize the same charging technology that PGE has installed for employee workplace charging.

Meanwhile, PGE workplace charging infrastructure is located at select PGE sites and was not installed to match the overnight parking locations of PGE fleet vehicles. For example, PGE has four Level 2 workplace charging ports at Beaverton Line Crew Center, which currently houses 45 light duty fleet vehicles and five plug-in light duty vehicles.

PGE's Sunset Line Crew Center currently has two Level 2 workplace charging ports and is home to 19 light duty fleet vehicles.

PGE workplace charging ports are also located in areas where employees park their vehicles, including public parking garages and unfenced areas near worksites. PGE typically parks fleet vehicles behind security fencing to reduce vandalism and the theft of expensive tools, materials, and equipment that are stored within or on the fleet vehicles. Medium and heavy-duty fleet vehicles may also not be able to maneuver and park in locations where charging infrastructure was placed to serve light-duty personal vehicles. Further, many of PGE workplace chargers are tied to building electrical services that cannot support the installation of additional charging infrastructure, further complicating the installation of additional ports.

Q. What other requirements support the need for PGE's investment in EV infrastructure?

A. PGE fleet vehicle charging needs are not exclusively outside of business hours. PGE crews work 24 hours per day and some fleet vehicles may require daytime charging for use at night. Other fleet vehicles may return to PGE locations periodically throughout the day to recharge as needed. Vehicles may also need to quickly recharge to prepare for anticipated Level III events or emergencies. These activities would be extremely difficult or impossible if done in coordination with employees charging their personal vehicles.

PGE's workplace charging stations were installed to support the specific charging of light-duty personal vehicles and are <u>not</u> appropriate for fleet applications. PGE has established higher performance and reliability standards for its fleet charging, to ensure that business critical vehicles are never stranded by malfunctioning charging equipment. This includes more robust internal components, equipment enclosures, charging cables, connectors, and access control hardware than PGE specifies for workplace charging applications. PGE is currently in the early stages of testing and evaluating appropriate Level 2 fleet charging infrastructure, none of which match the infrastructure selected for workplace charging.

PGE fleet vehicles may also require higher power output levels to charge larger batteries. PGE anticipates that electric pick-up trucks like the forthcoming Ford F-150 Lightning may have batteries as large as 170 kWh,[25] more than double the size of a Tesla Model 3, the most popular light duty passenger vehicle. Larger vehicle battery sizes may require more powerful Level 2 charging stations than are deployed at any PGE workplace charging location.

Lastly, PGE fleet charging infrastructure will have more robust cyber security capabilities than PGE's current workplace charging infrastructure. PGE fleet vehicle chargers must be network connected to facilitate remote monitoring and energy reporting to support fleet analysis and Clean Fuels Program credit claims and will likely utilize wired communication connections to PGE's internal network. PGE is also conducting extensive vetting with potential charging equipment providers to support robust cyber security measures. PGE workplace charging infrastructure utilizes cellular modems and are subject to different security vetting processes.

Q. What do you request of the Commission?

[25] https://insideevs.com/news/508674/battery-capacity-ford-f150-lightning/

A. We request that the Commission reject Staff's recommendation to disallow approximately $6.9 million in capital expenditures on new fleet charging sites from rate base, as well as Staff's recommendation to remove $330 thousand in O&M for fleet charging sites. PGE's investments in electrifying our fleet are prudent, aligned with investments of other entities, and further the state's goals to reduce GHG emissions.

C. TE-Related Line Extension Cost Recovery

Q. Please summarize Staff's concerns with PGE's calculation of TE-related Line Extension Allowances (LEA) and their proposed adjustments.

A. Based on its alternative calculation of LEAs, Staff finds that $393 thousand in capital expenditures on TE-related LEAs to be prudent but recommends $212 thousand in capital expenditures on TE-related LEAs be permanently removed from rate base. Staff also recommends exclusion of LEAs that are in progress now and are expected to be installed before April 30, 2022.

Q. Where does PGE address Staff's proposed adjustments to TE-related line extension allowances?

A. PGE Exhibit 2200 addresses Staff's proposals around TE-related line extension allowance calculations.

Q. Based on testimony in PGE Exhibit 2200, what do you propose?

A. We request that the Commission reject Staff's proposed LEA adjustments for the reasons outlined in PGE Exhibit 2200 and allow the full $605 thousand in capital expenditures in rate base.

Q. Did Staff propose any other adjustments?

A. Yes. While it is not mentioned in Staff's testimony, Staff's calculations of the proposed disallowance appear to categorically exclude LEAs for sites that are in progress and forecasted to be completed by April 30, 2022.

Q. Does PGE agree with this approach?

A. No. Each of these sites have progressed to the "Ready to Dispatch" status in PGE's line design workflow management system. PGE has no reason to believe that these sites will not be completed and in service by April 30, 2022.

Q. What is your request of the Commission?

A. We request that these LEAs be included in rate base as well.

D. TE-related O&M Expenses

Q. What is Staff's recommended adjustment for TE-related O&M expenses and what is their rationale for their recommendation?

A. Staff recommends the Commission approve recovery of approximately $1.6 million of TE-related O&M in base rates but that approximately $1.9 million be removed from PGE's forecast of TE O&M expenses. Staff proposes that PGE may only recover budgeted amounts previously approved by the Commission for TE O&M expense for Schedules 53 (Non-Residential Heavy Duty EV Charging) and 56 (Fleet Electrification Make Ready Pilot), plus PGE's forecasted O&M in the test year for its workplace charging infrastructure totaling $1.6 million – significantly less than the $3.5 million of TE-related O&M PGE requests. Staff recommends allowing only the expenditures it attributes to previously approved budgets and removing the difference from PGE's proposed O&M expense.

Q. Please explain why the additional $1.9 million in O&M expense is prudent and should be allowed in PGE's 2022 TE O&M forecast.

A. PGE's TE team develops and deploys the programs, partnerships, and infrastructure required to equitably support the use of electricity as a transportation fuel. PGE is guided in these efforts by EO 20-04 (2020), HB 2165 (2021), and Senate Bill (SB) 1044 (2019), along with the earlier guidance of SB 1547 (2015) and EO 17-21 (2017). Taken together, these legislative and administrative actions spanning the last six years represent a clear state policy to expedite transportation electrification in Oregon. These policies and other state actions set robust goals for zero emission vehicle adoption in Oregon over the next 15 years and recognize a central role for utilities to analyze infrastructure needs, begin preparing the built environment for electric vehicles, monitor grid impacts, and provide programs and incentives to help address barriers to equitable adoption.

As with any new endeavor, certain efforts occur at the initial stages. Product development and planning, and regulatory and stakeholder engagement processes require staff time, yet are not reflected in the O&M budgets of approved Division 87 TE programs. Given the new and rapidly evolving nature of the market, onboarding and training staff today, to meet the workforce needs of tomorrow, continues to be an important consideration.

PGE expects electric vehicle adoption in our service area to grow from 26,175 electric vehicles today (through the first half of 2021[26]) to over 100,000 by the end of 2025—nearly a 4-fold increase.[27] PGE's projections show this growth is expected to continue with an estimated 237,601 electric vehicles in PGE's service area by the end of 2030—a 9-fold

[26] https://www.oregon.gov/deq/ghgp/Documents/cfpResCredits2021p1.pdf
[27] https://edocs.puc.state.or.us/efdocs/HAA/haa165721.pdf

increase.[28] To ensure the equitable access to electricity as a transportation fuel for these vehicles, PGE's TE staff and operations budget must grow accordingly.

Q. What would be the impact on approved TE-related programs and PGE's ability to meet statutory requirements in support of TE if the Commission agrees with Staff to remove the additional $1.9 million in O&M expense from PGE's request?

A. PGE believes that Staff's recommendation fundamentally misunderstands the structure of PGE's TE efforts by incorrectly linking funding only to programs approved via rules set forth in Division 87. Consequently, Staff's recommendation is misaligned with state policy direction because considerable TE work takes place outside of Division 87 TE programs.

To address the broader direction of state policy, PGE has proposed a 17-person team to cover diverse workstreams that include the program management, development of new programs, regulatory and stakeholder engagement, internal change management, administrative support, vendor management, and infrastructure O&M. While some positions are covered under the three programs recommended for approval, Staff's proposed disallowances would leave many positions unfunded. The unfunded positions include those that would be responsible for development of the Transportation Electrification Plan and Transportation Electrification Investment Framework, positions that are not funded through Division 87 programs. Without these positions, PGE will not be able to develop new TE programs for filing under Division 87.

Additional staffing and resources are also required to operate and maintain existing and planned electric vehicle charging infrastructure. Staff's proposed budget also leaves the O&M of up to 150 new PGE fleet charging ports and the World Trade Center (WTC)

[28] Included in PGE's Distribution System Plan available at: Portlandgeneral.com/dsp

Electric Avenue unfunded. In fact, the WTC Electric Avenue is PGE's most highly utilized public fast charging site and the only fast charging infrastructure in downtown Portland. Leaving this charging infrastructure without maintenance risks a negative user experience as equipment goes untested or repaired and, at worst, could hinder PGE's operational needs and/or present a public safety hazard.

Staff's recommendation also removes outside services and other expenses, which include: 1) consultations with charging infrastructure safety experts for the review and enhancement of PGE safety documentation and procedures; 2) engagements with engineering services firms on site layout designs and improvements for accessibility, safety, and reliability; and 3) auxiliary contract services to perform routine and emergency repairs on PGE's charging infrastructure as programs and installations grow. PGE's 2022 TE O&M forecast also includes the business services required by the 17-member team in a highly technical and rapidly evolving industry, including engineering, management, analytical, and consulting services to help inform TE program designs, model electric vehicle adoption rates, project market trends, and other tasks.

Other expenses are heavily focused on ensuring PGE's field staff are trained and equipped to operate and maintain a quickly growing charging infrastructure portfolio. PGE's proposed budget includes formal training from charging infrastructure equipment manufacturers for field staff so that repairs can be self-performed, improving the speed at which repairs are conducted and lowering costs for PGE's customers. The forecast also includes specialized tools and test equipment to ensure work on all electrical equipment is done safely and that equipment is performing properly before it is released for use by the public. PGE also requires a robust spare parts inventory to help mitigate supply chain issues that would prevent PGE from procuring parts in a timely fashion.[29]

Overall, should Staff's recommendation be adopted, PGE will be unable to continue to develop the new programs outlined in Table 45 on Page 118 of PGE's 2019 Transportation Electrification Plan[30] to accelerate passenger vehicle adoption and fleet electrification, including new rates, make-ready infrastructure programs, and incentive programs. It would also hamper PGE's ability to develop programs as required by the monthly meter charge in HB 2165. The result would be for PGE to lag in executing its 2019 TE plan, developing its next TE plan, and advancing the state's zero emission vehicle goals established in Senate Bill 1044 (2019).

Q. What is your request of the Commission?

A. We request that the full scope of 2022 forecasted TE-related O&M expenses be approved, and that Staff's recommendation to disallow $1.9 million be rejected. In making this request, we note that in Order No. 19-395 adopting the amended UM 1811 stipulation, the Commission specifically "encourage[d] more steps toward realizing the legislative goals of increased transportation electrification."[31]

We acknowledge that the timing of this rate case is somewhat out of sync with the planning cycle of our next TE Plan and that this has left Staff without a clear view into PGE's TE plans. PGE looks forward to a robust and transparent engagement with Staff and stakeholders regarding budget, staffing and plans for the future, including through the TE Investment Framework (Docket UM 2165), Division 87 rulemaking planned for 2022, and

[29] For example, PGE was recently quoted a 42-week lead time for a direct current fast charging unit.
[30] https://edocs.puc.state.or.us/efdocs/HAA/haa165721.pdf
[31] Commission Order No. 19-385, November 7, 2019, page 1.

the company's next TE Plan. The company also welcomes the recommendations set forth in Staff Exhibit 2000, including quarterly stakeholder engagement, setting quantifiable metrics for medium-term goals, and exploring performance-based incentives.

E. Electric Island

Q. Please summarize Staff's recommendation regarding PGE's Electric Island project.

A. Staff observes that: 1) PGE executed a contract with Daimler Trucks North America (Daimler) to build a public charging station to refuel heavy-duty electric vehicles (i.e., Electric Island project) without having a tariff in place to provide these services; 2) a tariff cannot apply retroactively to an investment already made (i.e., Schedule 53, which the Commission approved later, does not apply); 3) providing services without a tariff is inherently imprudent; and 4) this investment would not be prudent even if the investment benefitted ratepayers. Consequently, Staff recommends that PGE only be allowed to recover, via the Company's UM 1938 deferral, labor costs incurred in 2020 providing technical assistance to the Electric Island project as an expense but that approximately $1.6 million in capital expenditures be permanently removed from rate base.

Q. Do you agree with Staff's recommendation?

A. No. We believe that PGE's investment in the Electric Island project was prudent and reasonable and should not be disallowed.

Q. How does the Electric Island project further the state's TE goals and benefit ratepayers, and how does that support a finding that those capital expenditures were prudent?

A. The early learnings captured from Electric Island will enable PGE to serve heavy duty vehicle charging loads in a more cost-efficient manner, benefiting all ratepayers. Learning from this project also aligns with HB 2165 (2021), which recognizes a significant role for utility infrastructure investment in transportation electrification, including behind the customer meter. PGE provided a detailed analysis of these benefits in PGE's Response to UE 389 OPUC Data Request No. 33[32], showing Schedule 53 could provide PGE with approximately $4.0 million in benefits from the avoided construction of new feeders, the avoided reconductoring of feeders, improved availability of future vehicle to grid and demand response technologies, and the development of safety and training protocols. Because Schedule 53 was designed to accommodate from one to three heavy-duty electric vehicle charging demonstration sites, PGE proposes that one-third of these benefits be attributed to Electric Island, resulting in approximately $1.4 million in associated future benefits.

We also anticipate that Electric Island will provide grid services from the planned deployment battery energy storage systems, demand response enabled charging infrastructure, and vehicle to grid-capable charging infrastructure. PGE valued these benefits for the one to three sites at $0.9 million. PGE again proposes that one-third of these benefits be attributed to Electric Island, resulting in approximately $0.3 million in associated benefits. Combined, these $1.7 million in benefits more than outweighing the capital PGE is seeking to recover for Electric Island.

Q. Please summarize how Electric Island expanded public knowledge about TE.

A. Since its energization in April 2021, the Electric Island site has hosted a number of highly public events, including the comprehensive clean energy bill signing ceremony headlined by

[32] A copy of PGE's response to UE 389 OPUC Data Request No. 33 is provided as Exhibit 1706.

Gov. Brown and subsequent visits by Senator Merkley and Representative Bonamici. These visits serve to promote the investments that PGE, vehicle manufacturers, and EV charger manufacturers are committing to the medium-duty (MD) and heavy-duty (HD) charging space, and garnered significant press nationally.

PGE has also hosted well over two dozen site tours at Electric Island. Attendees have included developers, consulting firms, EV charging manufacturers, Heavy Duty Truck manufacturers, local and regional transportation-focused non-profits, truck stop operators, truck fleets, charge network providers, electric utilities, and students from local universities. Daimler has additionally hosted a number of fleet customers interested in electrifying their fleets at the site. The range of questions and the eagerness of the audience to learn more during these tours has been tremendous, and the broad sharing of lessons-learned will increase the successful spread of MD/HD vehicle charging.

Q. Did Electric Island buildout provide learning opportunities for PGE staff?

A. Yes. There were significant learnings during design and construction of Electric Island, including the layout of the site, challenges during installation of the electric infrastructure, and recommended civil/structural practices for installing the chargers so they can be replaced by newer equipment. These experiences have been presented at the Oregon Solar + Storage conference, the Sustainable Fleet Technology Conference and Exposition, the Green Transportation Summit & Expo, the EPIC Forum: Innovative Technologies to Accelerate MHD Electrification, the UTC Telecom & Technology Conference, and the Fuels Institute. The presentations have also stimulated follow-up conversations with a number of Oregon customers around how they might integrate MD and HD charging into their own upcoming infrastructure buildouts.

In addition, Electric Island serves as a location for interoperability testing. Customers such as TriMet and FlixBus use the site to quickly test whether their EVs can complete the "handshake" and successfully charge with a number of different chargers. Electric Island currently has eight DC Fast Chargers representing seven different models, allowing a testing opportunity that is not widely available across the state, or even the nation.

The chargers at the site have been automated to generate loading data, including the total site load, the average length and energy used during a charging session, and typical times of peak use. This information is being aggregated into monthly and annual reports, and the data will feed into parallel PGE efforts such as sizing for internal PGE fleet infrastructure and guidance for the Fleet Build program as PGE helps customers design the electrical capacity and site size/layout for their own facilities.

Q. What do you request of the Commission?

A. PGE asks that the Commission reject staff's proposal to disallow the recovery of capital related to Electric Island. Although PGE incurred costs prior to filing and receiving approval for Schedule 53, this was largely inadvertent due to the expectation of legislative authority that did not materialize. In spite of this, we believe the costs were prudent because the Commission did approve Schedule 53 and because the Electric Island project will lead to significant avoided cost benefits, has increased public awareness of TE, and has provided crucial learning opportunities for PGE and many other interested parties.

V. Conclusion

Q. Please summarize your position regarding issued identified by Parties.

A. We recommend the Commission reject the Parties' proposals regarding the issues identified. Our proposals are summarized below:

- Customer Service O&M costs: Staff took a narrow view of one department and one FERC account to determine disallowances, however, PGE's business practices are more interrelated and looking at variance in Account 908 as a whole is a more reasonable approach which shows that PGE's expenses are just and reasonable.
- FFBC – Non-Residential FFBC Program: Staff's proposed adoption rate of 3% is significantly lower than the actual adoption rates of FFBC program. PGE asks the Commission to deny Staff's proposed adoption rate and allow FFBC offering to all customers retaining the current limit of $5,000.
- FFBC – Amazon Pay: Increasingly customers across utilities are using digital wallets for purposes of transaction security. Additionally, Amazon Pay is used relatively less than other digital wallets. As a result, the benefits of offering this payment option outweighs the minimal costs of the offering and PGE asks that the Commission reject CUB's proposal to disallow Amazon Pay as a payment option.
- TE – Capital in UM 1811: Commission Order No. 19-385 determines maximum allowable costs of directly incurred capital costs. PGE's request of unloaded labor costs is below the maximum allowable costs, therefore, PGE request that Commission rejects Staff's proposal of disallowance based on exceeding maximum allowable costs.

- TE – Fleet Electrification: PGE does not believe that electrification of our own fleet falls under Division 87 rules. Additionally, PGEs investment in fleet electrification aligns with Executive Order 20-04. As a result, we ask that the Commission allow recovery of costs related to electrification of PGE's fleet.
- TE – O&M Budget: Staff's proposed adjustment allowed for the recovery of costs related to only approved programs. Due to the recent initiatives by the State of Oregon to reduce GHG emissions and increase TE adoption, PGE's request for TE program expenses is just and reasonable. Additionally, Staff's adjustment did not include funds for maintenance of existing TE infrastructure such as downtown Portland Electric Avenue and PGE fleet charging stations. PGE asks that the Commission reject Staff's adjustments.
- TE – Electric Island: Early learnings from the Electric Island project will provide a benefit to ratepayers of $1.7 million, more than supporting the capital expenditure. This project has also furthered public awareness of charging infrastructure of heavy-duty vehicles. Additionally, the project has several different types of chargers allowing for testing scenarios that are not accessible in other parts of the state. PGE asks that the Commission allow the recovery of capital costs related to Electric Island.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
1701	EEI – CEO Policy Committee on Customer Solutions Meeting
1702	PGE’s Response to OPUC Data Request No. 746
1703	TriMet and Electric Avenue Network capital costs
1704C	PGE’s Response to OPUC Data Request No. 150, Attachment E
1705	GE’s Response to OPUC Data Request No. 932
1706	PGE’s Response to UE 389 OPUC Data Request No. 33

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CEO Policy Committee on Customer Solutions Meeting (Virtual)

October 13, 2021, 1:00-2:00 pm (EDT)

Briefing Materials

EEI Power by Association℠

CEO Policy Committee on Customer Solutions

Virtual Meeting Agenda

Wednesday, October 13, 2021, 1:00 - 2:00 pm (EDT)

(Via WebEx – see calendar appt)

EEI Co-Chairs: Jerry Norcia, President & Chief Executive Officer, DTE Energy
Maria Pope, President & Chief Executive Officer, Portland General Electric

Attendees: CEO Policy Committee on Customer Solutions members and Chief Customer Officers

1:00 pm **Welcome and Meeting Overview**

1:05 – 1:35 pm **Residential Customer Initiatives to Improve/Enhance Customer Service**

- Better understanding and serving the **low to moderate income (LMI)** customer group: Project with E Source using Customer Centricity approach.
- Invited speaker: Peter Fader, Professor of Marketing, Wharton School, University of Pennsylvania. Author: *The Customer Centricity Playbook*
- Rethinking customer **payment enablement approaches** to better serve customers: Update on next steps

1:35 – 1:45 pm **Military Customers/Federal Agencies: Engagement Opportunities**

- Carbon-free energy and electric transportation solutions
- EEI-Army MOU on Energy Resiliency

1:45 – 2:00 pm **Corporate Customers/National Key Accounts**

- Developing a consistent carbon emissions reporting framework for investors, corporate customers, and other stakeholders

2:00 pm **Adjourn**

Rethinking LMI customer offerings and engagement: Project with E Source

Industry Research

1 **Define Objective and Value**
- Scope, desired outcome
- Value of achievement

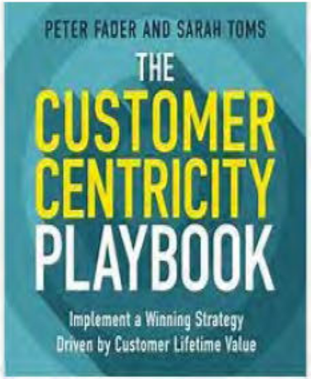
2 **Develop Digital Replica of Each Individual Customer**
- AMI Energy Profile
- Behavioral Profile

3 **Identify BEST Customer Cohorts**
- Individual Customer Assessments
- AI-derived Micro-Cohorts

4 **Create Cohort Personas**
- Key data attributes identified
- Humanize w/ VOC Ethnography

5 **Develop/Refine Programs**
- Design Thinking Workshop
- Program Design

6 **Go-To-Market Plan**
- Personalized Engagement
- Program/Engagement Feedback



"Audience of One"

Note: Shaded areas are excluded from the project

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Customer Solutions

Guest Speaker: Peter Fader

Peter S. Fader is the Frances and Pei-Yuan Chia Professor of Marketing at The Wharton School of the University of Pennsylvania. His expertise centers around the analysis of behavioral data to understand and forecast customer shopping/purchasing activities.

He works with firms from a wide range of industries, such as telecommunications, financial services, gaming/entertainment, retailing, and pharmaceuticals. Managerial applications focus on topics such as customer relationship management, lifetime value of the customer, and sales forecasting for new products. Much of his research highlights the consistent (but often surprising) behavioral patterns that exist across these industries and other seemingly different domains.

Fader is the author of *Customer Centricity: Focus on the Right Customers for Strategic Advantage* and coauthor with Sarah E. Toms of the book *The Customer Centricity Playbook*. He has been quoted or featured in *The New York Times*, *The Wall Street Journal*, *The Economist*, *The Washington Post*, and on NPR, among other media. In 2017, Professor Fader was named by Advertising Age as one of its inaugural “25 Marketing Technology Trailblazers,” and was the only academic on the list.

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Snapshot of Customer Payment Options & Transition to Fee-Free Credit Cards, Digital Payments, and Other Convenient Channels

(DRAFT - October 2021 - does not include all EEI members)

Over the past several years, aligning with payment trends of other industries, EEI member companies have increased choice in payment options by establishing digital and fee-free options and other convenient channels. Offering payment options that customers want increases payments and customer satisfaction.

Member Company & State		Credit Card Payments	Digital Payment Options (some with fees)								Non-Digital Payment Channels (some with fees)		
Company	State	Fee Free	Mobile App	Amazon Pay	Apple Pay	Google Pay	PayPal	Venmo	Pay-By-Text	Voice Assistant	Pay Stations/ APA	Walk-in Locations	Kiosks
AEP (Indiana Michigan Power)	IN MI	✓	✓								✓		
Alabama Power	AL		✓	✓	✓	✓	• Fee	• Pending			✓		
Alliant Energy (Interstate Power and Light Company)	IA	✓	✓						✓		✓		
Alliant Energy (Wisconsin Power and Light Company)	WI	✓	✓						✓		✓		
Ameren Missouri	MO	✓	✓								✓		
Arizona Public Service	AZ	✓	✓				• Fee	• Fee			✓		
Avista	ID WA	✓	✓						✓		✓		
Central Hudson	NY	✓	✓								✓	✓	
ConEdison	NY	✓	✓		✓			✓		✓		✓	
Consumers Energy	MI	✓							✓		✓		
Dominion Energy	VA NC		✓	• Fee			• Fee	• Fee					
Dominion Energy	SC	✓									✓		
DTE Energy	MI	✓	✓								✓		✓
Duke Energy	NC	✓	✓								✓		
Duke Energy	SC	✓	✓								✓		
Duke Energy	FL	✓	✓								✓		
Eversource	CT	✓							✓		✓		
Eversource	MA	✓							✓		✓		
Eversource	NH	✓							✓		✓		
Georgia Power	GA	✓		✓	✓	✓	✓	• Pending			✓		
Madison Gas & Electric	WI	✓							✓		✓		
Minnesota Power	MN	✓							✓		✓		
Mississippi Power	MS	✓		✓	✓	✓	✓	• Pending			✓		
National Grid	MA	✓									✓		

Snapshot of Customer Payment Options & Transition to Fee-Free Credit Cards, Digital Payments, and Other Convenient Channels
(DRAFT - October 2021 - does not include all EEI members)

Over the past several years, aligning with payment trends of other industries, EEI member companies have increased choice in payment options by establishing digital and fee-free options and other convenient channels. Offering payment options that customers want increases payments and customer satisfaction.

Member Company & State		Credit Card Payments	Digital Payment Options (some with fees)								Non-Digital Payment Channels (some with fees)		
Company	State	Fee Free	Mobile App	Amazon Pay	Apple Pay	Google Pay	PayPal	Venmo	Pay-By-Text	Voice Assistant	Pay Stations/ APA	Walk-in Locations	Kiosks
NorthWestern Energy	MT SD								✓		✓	✓	
NV Energy	NV		✓								✓		
NY State Electric & Gas	NY	✓									✓		
Orange & Rockland	NJ NY	✓								✓	✓	✓	
Portland General Electric	OR	✓	✓	✓	* (2022)	* (2022)	✓				✓	✓	
PPL Corporation	KY PA VA				✓				✓		✓		
Public Service of New Mexico	NM				* (2022)	* (2022)					✓	✓	
Puget Sound Energy	WA	✓	✓								✓		
Rochester Gas & Electric	NY	✓									✓		
Superior Water, Light & Power Company	WI	✓							✓		✓		
TECO	FL										✓		
Xcel Energy	CO, MI MN, ND NM, SD TX		✓		✓	✓					✓		

Edison Electric INSTITUTE

Customer Solutions

Department of Defense Customer EAC Subcommittee

Subcommittee Members

- Jimmy Alberts, SVP, Operations, Hawaiian Electric Industries
- Aaron August, VP, Business Development & Customer Engagement, Pacific Gas & Electric Company
- Mike Bushey, Director, Business Customer Division, Southern California Edison
- Monica DeAngelo, Director, Federal Partnerships, Southern Company
- Phil Dion, Chief Customer Officer, American Electric Power
- Dallas Dukes, VP, Energy Programs and Pricing, UNS Energy Corporation
- Chris Edge, VP of Large Business Customers, Duke Energy
- Gaylene Watson, Director Customer Service & Strategic Partnerships, Dominion Energy, Inc

EEI Staff

- Steve Kiesner, Senior Director, National Customer Solutions, EEI
- Alexandra Young, Manager, DoD and Federal Customer Solutions, EEI
- Lisa Wood, VP, Customer Solutions, EEI

MEMORANDUM OF UNDERSTANDING
BETWEEN
THE EDISON ELECTRIC INSTITUTE
AND
THE U.S. DEPARTMENT OF THE ARMY
FOR
JOINT ENERGY RESILIENCE PLANNING

This Memorandum of Understanding ("MOU"), entered into on 27 May, 2021, is by and between the Edison Electric Institute ("EEI") and the United States Department of the Army ("the Army") (hereinafter "the Parties") to pursue their mutual interest in developing best practices for joint energy resilience planning for certain domestic Army installations.

I. BACKGROUND AND PURPOSE

EEI is the association that represents all U.S. investor-owned electric companies (hereinafter referred to as "serving electric companies"). EEI members provide electricity for about 220 million Americans, including over 300 military installations, and operates in all 50 states and the District of Columbia.

The Army stands ready to defend the Nation and its interests against current and emerging threats. It must be able to accomplish its mission in a world defined by uncertain, adverse, and dynamic conditions. Army installations and enduring locations overseas must provide world-class training facilities, project power, surge the industrial base, sustain the force, and maintain command and control; this is only achievable with secure and resilient energy.

The Army has a long history of working closely with its utilities to meet its resilience, efficiency, and affordability goals.

In the 2018 National Defense Strategy, the Department of Defense ("DoD") declared that the U.S. homeland is no longer a sanctuary and that attacks by adversaries against U.S. critical defense, government, and economic infrastructure should be expected. This conclusion amplified the Army's long-held concern that critical missions performed at its domestic installations could be compromised significantly if the electricity grid that serves its installations incurs physical and/or cyber attacks.

To help address energy resilience concerns, Army installations have been engaged with their serving electric companies to assess electrical grid vulnerabilities and infrastructure investments that may impact its mission operations. The Army is also pursuing "inside the fence-line" solutions at its installations to ensure it can sustain critical missions by being capable of withstanding an extended utility outage for a duration set by the senior commander, or higher headquarters. When the duration of the critical mission(s) has not been stipulated, the Army will plan to sustain energy and water for a minimum of 14 days.

While there already are some examples of serving electric companies collaborating with the Army installations to enhance energy resiliency, the purpose of this MOU is to allow the Parties to facilitate dialogue and coordinated actions to identify potential opportunities for investment initiatives or other initiatives for improving the reliability and resilience of the electric service for Army installations and their communities.

The objectives for this exercise will be accomplished through the following process:

1. EEI and the Assistant Secretary of the Army for Installations, Energy and Environment shall both designate a lead person on behalf of each organization (the "Leads").
2. The EEI and Army designated Leads will identify one or more Army installation(s) and its serving electric company(-ies) that will pilot the initiative.
3. Learning from, and working in concert with the pilot participants, the Leads will identify key potential communication gaps and develop recommendations to address them. The Leads also will identify opportunities to align the common energy resiliency goals, and initiatives of the Army, serving electric companies, and nearby communities to create best practices for joint planning to optimize potential future investments for grid resilience, community resilience, and for national security interests.
4. The EEI and the Army Leads will provide status reports to its CEO DoD Task Force on Energy Resilience and the Assistant Secretary of the Army, respectively, as needed and appropriate.
5. The Leads, working with EEI and for review by the Assistant Secretary, will produce a document that identifies potential opportunities to improve the resilience of Army installations will be completed in the 4th quartile of 2021.

II. RESPONSIBILITIES OF THE PARTIES

Edison Electric Institute (EEI)

1. EEI will conduct interviews and other research with key participants consistent with the goals and objectives of this MOU.
2. EEI will convene monthly meetings with the Army Office of Energy Initiatives, (and, as needed, pilot participants from serving electric companies and Army installations, and other key stakeholders) to review workplans, content, and progress of initiatives that are consistent with this MOU.
3. EEI will identify and confirm one or more serving electric companies to serve as pilot participant(s). The scope, obligations, and responsibilities of the pilot participants will be established outside of this MOU.
4. EEI will create a best practices document that identifies potential opportunities to improve the resilience and reliability issues identified in this MOU.
5. Upon completion, EEI will distribute the best practices document to its membership, and, when appropriate, other key stakeholders such as state utility commissions.

The Army

1. The Army will provide EEI with access to all relevant Army personnel for interviews consistent with goals and objectives of this MOU. This includes Army leadership at the installation management and enterprise command levels. No confidential or mission sensitive information shall be provided during these interviews.
2. The Army will identify and confirm one or more Army installations to serve as pilot participants with the selected serving electric company(-ies). The scope and responsibilities of the pilot participants will be established outside of this MOU.

3. The Army will participate in monthly meetings with EEI, pilot participants, and other key stakeholders to review workplans, content, and progress of the best practices.
4. Upon completion, the Army will distribute the best practices document to its U.S. based installations and to relevant Army leadership, including the Assistant Secretary for Installations, Energy, and Environment.

III. POINTS OF CONTACT

The following Leads will be used by the Parties to communicate in the implementation of this MOU. Each Party may change its point of contact upon notice to the other Party.

For EEI:

Primary: Mr. Stephen Kiesner, Senior Director, National Customer Markets (skiesner@eei.org)
Alternate: Ms. Jacque Elliot, Director, National Customer Markets (jelliot@eei.org)

For the Army:

Primary: Mr. David Irwin. Director Opportunity Development (david.j.irwin22.civ@mail.mil)
Alternate: Ms. Krista Stehn, Director Business Operations (krista.r.stehn.civ@mail.mil)

IV. TERM AND TERMINATION.

1. This MOU shall remain in effect for a period of one year from the effective date.

2. This MOU may be terminated at any time by either party, with or without cause, by providing written notice to the other party.

V. GENERAL PROVISIONS

1. This MOU in no way restricts either of the Parties from participating in any activity with other public or private agencies, organizations or individuals.

2. This MOU is neither a fiscal nor a funds obligation document. Nothing in this MOU authorizes or is intended to obligate the Parties to expend, exchange, or reimburse funds, services, or supplies, or transfer or receive anything of value.

3. This MOU is strictly for internal management purposes for each of the Parties. It is not legally enforceable and shall not be construed to create any legal obligation on the part of either Party, including that of a federal contractor. This MOU shall not be construed to provide a private right or cause of action for or by any person or entity.

4. This MOU is subject to, and will be carried out in compliance with, all applicable laws, regulations and other legal requirements.

5. This MOU may be modified by mutually acceptable written amendment duly executed by authorized officials of DoD and EEI.

6. This MOU constitutes the full and final understanding of both Parties on all subjects contained within it. All prior negotiations, understandings, and agreements are merged into this MOU.

By affixing their signature below, each Party has caused this MOU to be executed by their duly authorized representative.

U.S. DEPARTMENT OF THE ARMY

By:______________________

Mr. John "Jack" Surash

Senior Official Performing the Duties

Of Assistant Secretary of the Army

(Installations, Energy and Environment)

Date: May 27, 2021

EDISON ELECTRIC INSTITUTE

By:______________________

Mr. Thomas R. Kuhn

President

Date: 05/27/21

Edison Electric INSTITUTE

Customer Solutions

Opportunity for EEI to Lead Development of a Consistent Carbon Emissions Reporting Framework

(Draft for Discussion – October 2021)

Over the past five years, EEI has led efforts to develop two distinct sustainability-related reporting frameworks for EEI members to voluntarily report: (1) ESG/sustainability information to investors, and (2) carbon emissions information to corporate customers.

1. The ESG/sustainability reporting template has been developed for EEI member companies to report information to investors [available here: https://www.eei.org/issuesandpolicy/Pages/FinanceAndTax-ESG.aspx]. Investors use this information to evaluate the ESG profile of companies based on standardized information, including qualitative information (related to ESG/sustainability governance and strategy) and quantitative information (such as generation, GHG emissions, human resources, and other relevant ESG data). GHG emissions data is reported in terms of direct (emissions from owned generation) and indirect (emissions from purchased power) so investors can evaluate the profile of a company based on assets and operations.
2. The electric company carbon emissions and electricity mix reporting database has been developed by EEI for corporate customers to use to streamline access to carbon dioxide (CO_2) intensity rates for delivered electricity by EEI operating company accounting for Renewable Energy Certificates (RECs) and green tariff programs using accepted protocols [available here https://www.eei.org/Pages/CO2Emissions-Access.aspx]. This database also provides the electricity mix by fuel as well as qualitative information by EEI member operating company. Corporate customers use these CO_2 rates to calculate their Scope 2 emissions from delivered electricity for reporting and disclosure of carbon-related sustainability goals.

Both templates provide valuable information – one for investors and one for corporate customers. And, both templates provide annual emissions information. The major difference between the reported carbon emissions in the two templates is the accounting for RECs and green tariff programs in the database for corporate customers. Adhering to a GHG accounting protocol primarily intended for end-users of electricity to report Scope 2 emissions can be misleading for investors that seek to understand the direct operations and emissions profile of an electric company. Hence, two templates exist today.

However, it is confusing to have two distinct templates and we are also aware of inconsistencies that exist within each of the templates in how values are reported across the EEI member companies.

Recent events and trends point to the need to develop a consistent approach to reporting this type of information across the EEI membership that will serve investors, corporate customers, and other stakeholders by addressing inconsistencies to the extent possible. * These include:

- Request for public input from the Securities and Exchange Commission (SEC) regarding ESG and climate change disclosures (see EEI/AGA filed comments https://www.sec.gov/comments/climate-disclosure/cll12-8861705-240106.pdf).
- Forthcoming SEC Notice of Proposed Rulemaking (NOPR) on ESG and Climate Change Disclosures expected in early December.
- Forthcoming Federal Trade Commission update of *Green Guides* expected in 2022.
- Corporate customer accounting shifting toward matching carbon free-energy delivered to energy used hour-by-hour (rather than on an annual basis).

Once SEC ESG and climate change disclosure rules go into effect, consistent reporting will be essential. To help shape the development of those rules, it is important that we begin coordinating efforts now – prior to release of the SEC NOPR – to develop a consistent approach to reporting carbon emissions and intensity rates (tons of CO_2 per MWh) that can be used by investors, customers, and other stakeholders.

In addition to the forthcoming SEC NOPR, the Federal Trade Commission (FTC) intends to initiate review of the *Guides for the Use of Environmental Marketing Claims* (known as *Green Guides*) in 2022. For electric companies, the crux of the issue is in the characterization, accounting, and disclosure of renewable energy when the REC is sold separately from the electricity itself. Green Guides protect consumers and ensure claims made by companies about the environmental attributes of their products are truthful and non-deceptive (i.e., to prevent greenwashing). The sale of a REC is a common and legal practice. As EEI and its members work towards consistency in accounting and reporting of carbon emissions for use by investors, corporate customers, and other stakeholders, it is important to ensure that industry statements about 100% renewable energy supply options continue to follow the Green Guides.

Note: Some of the reasons for inconsistencies in carbon emissions reporting that need resolution include the following:

- Appropriate accounting for RECs and Green Tariffs
- Purchased power emissions factors
- Market purchase emissions factors
- Concerns about consistency with state reporting requirements
- Data provided to other external reports (EIA Form 923, FERC Form 1, etc.)

EEI NATIONAL KEY ACCOUNTS
Connections That Mean Business
FALL WORKSHOP OCT 24-27, 2021 LONG BEACH, CA

Register now and join your peers at EEI's Fall National Key Accounts Workshop, October 24-27, in Long Beach, CA.

Build powerful relationships with national corporate customers, see the Freightliner eCascadia 100% battery electric semi-truck in the Energy Marketplace, and network with peers who share similar responsibilities and priorities at the workshop.

View the latest agenda and participating companies. Listed below is a few of the business topics and session highlights.

- Leaders from Edison International, General Motors, and Walmart will discuss strategies for achieving 100% carbon free.
- McDonald's and the CEOs of Volt Energy, VGI Energy, and Solar Stewards share how corporate customers can drive progress in diversity, equity, and inclusion in the energy marketplace.
- Representatives from 7-Eleven, AT&T, CSX Transportation, Dollar Tree, and Publix will discuss their unique energy and reliability needs and how best electric companies can serve their sectors.
- Companies around the globe are electrifying their fleets to save on fuel and reduce operating costs, while meeting environmental targets and goals. Hear from leaders in the EV space on navigating this explosive market and lessons learned. Greenlots CEO, Andreas Lips, will share how they are powering this transformation by providing reliable and accessible EV charging solutions.
- Join Costco Wholesale and Dillard’s for a conversation on the essential role energy managers play in supporting true carbon reduction.
- Representatives from Southern California Edison, Ratio Institute and California State University will discuss carbon reduction strategies and some innovative performance based GHG reduction programs being piloted.
- Hear from a panel of representatives from Southern Company, Dominion, and Microsoft on the best approach to doing business with datacenters and the characteristics companies look for in datacenter expansion.
- Live demonstrations of heavy and light duty EVs, electric kitchen equipment, and drones utilized for PSPS events will take place in the Energy Marketplace
- Additional topics will include: Planning for refrigeration phase outs, energy resiliency, and an update on the latest building codes and energy efficiency regulations in California and beyond.

COVID-19 Information: Please know that EEI takes your health and well-being very seriously. EEI requires that all in-person meeting attendees, including guests, be fully vaccinated against COVID-19. Attendees can review the full COVID-19 safety protocols and vaccination policy for EEI meetings on our Workshop website.

If you have any questions about the Fall Workshop, do not hesitate to reach out to jelliot@eei.org.

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 746
Dated September 14, 2021

Request:

Please list all TE-related capital expenditures PGE is seeking recovery for with line item detail, line item cost, expenditure date, and program the expenditure falls under.

Response:

Attachment 746-A provides requested information.

OPUC DR 746 - TE Expenditures in Rate Case Filing

Program	FP	Charge	Cost Element	Vendor Information	Month	Amount
UM 1811 - TriMet	P36460	AFUDC debt charge	5001: AFUDC Debt		201805	$ 654.19
UM 1811 - TriMet	P36460	AFUDC equity charge	5002: AFUDC Equity		201805	$ 1,247.81
UM 1811 - TriMet	P36460	Charging Station Kit - Sunset	2250: Other Outside Services	GILLESPIE DECALS INC	201908	$ 2,090.00
UM 1811 - TriMet	P36460	Construction Overhead	5303: Construction Overhead		201908	$ 393.96
UM 1811 - TriMet	P36460	Installation - Sunset Transit	2250: Other Outside Services	GILLESPIE DECALS INC	201908	$ 1,035.00
UM 1811 - TriMet	P36460	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201908	$ 3.49
UM 1811 - TriMet	P36460	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201908	$ 0.85
UM 1811 - TriMet	P36460	TriMet Mass Transit 2.0	2110: Other Materials	TRI-COUNTY METRO TRANSP	201805	$ 625,000.00
UM 1811 - Electric Avenue	P36462	Flagging Services	2210: Flagging Services	NW TRAFFIC CONTROL INC	201911	$ 585.60
UM 1811 - Electric Avenue	P36462	Flagging Services	2210: Flagging Services	NW TRAFFIC CONTROL INC	202002	$ 559.60
UM 1811 - Electric Avenue	P36462	(Qty 10)- Sky Commissioning	2250: Other Outside Services	ZECO SYSTEMS INC	202003	$ 1,500.00
UM 1811 - Electric Avenue	P36462	(Qty 2)- BTC Cord Retractor ¿¿¿	2250: Other Outside Services	ZECO SYSTEMS INC	201909	$ 1,200.00
UM 1811 - Electric Avenue	P36462	(Qty 2)- BTC EVP-FC200 Modular	2250: Other Outside Services	ZECO SYSTEMS INC	201909	$ 95,680.00
UM 1811 - Electric Avenue	P36462	(Qty 2)- Cellular Data Fees (1	2250: Other Outside Services	ZECO SYSTEMS INC	202003	$ 1,920.00
UM 1811 - Electric Avenue	P36462	(Qty 2)- Level 2 BTC Power Out	2250: Other Outside Services	ZECO SYSTEMS INC	201909	$ 8,160.00
UM 1811 - Electric Avenue	P36462	(Qty 8)- High Powered Charger	2250: Other Outside Services	ZECO SYSTEMS INC	201909	$ 199,592.00
UM 1811 - Electric Avenue	P36462	2020 Electronic Filing Fee	2950: Other Taxes & Governmental Fees	SIMPLIFILE LC	201908	$ 122.00
UM 1811 - Electric Avenue	P36462	2020 Electronic Filing Fee	2950: Other Taxes & Governmental Fees	SIMPLIFILE LC	201909	$ 236.00
UM 1811 - Electric Avenue	P36462	350KW Charging station repair	2250: Other Outside Services	GILLESPIE DECALS INC	201905	$ 890.00
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201901	$ 124,584.00
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201902	$ (46,584.00)
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201903	$ (78,000.00)
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201904	$ 10,000.00
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201905	$ (10,000.00)
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201906	$ 234,000.00
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201907	$ (234,000.00)
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201909	$ 35,808.60
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201910	$ (35,808.60)
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201911	$ 44,600.00
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		201912	$ 13,435.00
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		202001	$ (40,035.00)
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		202002	$ (18,000.00)
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		202006	$ 90.00
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		202008	$ 11,910.00
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		202011	$ 4,000.00
UM 1811 - Electric Avenue	P36462	Accrual	5404: Accrual		202101	$ (4,000.00)
UM 1811 - Electric Avenue	P36462	ADA Guidelines for Sites #4-#6	2250: Other Outside Services	BLACK & VEATCH CORPORATIO	201912	$ 6,768.00
UM 1811 - Electric Avenue	P36462	ADA SIGN POST WHEELSTOP THERMO	2250: Other Outside Services	COAST SWEEPING SERVICES INC	202101	$ 4,022.80
UM 1811 - Electric Avenue	P36462	Additional Landscaping	2213: Landscape Services	PACIFIC LANDSCAPE MGMT INC	201911	$ 1,092.00
UM 1811 - Electric Avenue	P36462	AFUDC debt charge	5001: AFUDC Debt		201904	$ 184.73
UM 1811 - Electric Avenue	P36462	AFUDC debt charge	5001: AFUDC Debt		201905	$ 177.04
UM 1811 - Electric Avenue	P36462	AFUDC debt charge	5001: AFUDC Debt		201906	$ 88.77

UM 1811 - Electric Avenue	P36462	AFUDC debt charge	5001: AFUDC Debt		201911	$	1,696.87
UM 1811 - Electric Avenue	P36462	AFUDC debt charge	5001: AFUDC Debt		201912	$	1,450.19
UM 1811 - Electric Avenue	P36462	AFUDC debt charge	5001: AFUDC Debt		202001	$	1,991.19
UM 1811 - Electric Avenue	P36462	AFUDC debt charge	5001: AFUDC Debt		202002	$	851.46
UM 1811 - Electric Avenue	P36462	AFUDC debt charge Adjustment	5001: AFUDC Debt		201912	$	(1,178.78)
UM 1811 - Electric Avenue	P36462	AFUDC debt charge Adjustment	5001: AFUDC Debt		202002	$	(155.52)
UM 1811 - Electric Avenue	P36462	AFUDC equity charge	5002: AFUDC Equity		201904	$	343.61
UM 1811 - Electric Avenue	P36462	AFUDC equity charge	5002: AFUDC Equity		201905	$	362.72
UM 1811 - Electric Avenue	P36462	AFUDC equity charge	5002: AFUDC Equity		201906	$	175.20
UM 1811 - Electric Avenue	P36462	AFUDC equity charge	5002: AFUDC Equity		201911	$	3,538.27
UM 1811 - Electric Avenue	P36462	AFUDC equity charge	5002: AFUDC Equity		201912	$	2,908.72
UM 1811 - Electric Avenue	P36462	AFUDC equity charge	5002: AFUDC Equity		202001	$	4,019.55
UM 1811 - Electric Avenue	P36462	AFUDC equity charge	5002: AFUDC Equity		202002	$	1,715.49
UM 1811 - Electric Avenue	P36462	AFUDC equity charge Adjustment	5002: AFUDC Equity		201912	$	(2,457.96)
UM 1811 - Electric Avenue	P36462	AFUDC equity charge Adjustment	5002: AFUDC Equity		202002	$	(313.93)
UM 1811 - Electric Avenue	P36462	ARRESTOR, LIGHTNING, DISTRIBUT	2101: Storeroom Materials		201909	$	55.37
UM 1811 - Electric Avenue	P36462	BTC EVP-FC200 Modular Level 4	2250: Other Outside Services	ZECO SYSTEMS INC	201902	$	23,920.00
UM 1811 - Electric Avenue	P36462	BTC EVP-FC200 Modular Level 4	2250: Other Outside Services	ZECO SYSTEMS INC	201903	$	23,920.00
UM 1811 - Electric Avenue	P36462	BTC EVP-FC200 Modular Level 4	2250: Other Outside Services	ZECO SYSTEMS INC	201904	$	23,920.00
UM 1811 - Electric Avenue	P36462	BTC EVP-FC200 Modular Level 4	2250: Other Outside Services	ZECO SYSTEMS INC	201907	$	71,760.00
UM 1811 - Electric Avenue	P36462	C/O #1: Additional Constructio	2110: Other Materials	EV4 LLC	201912	$	9,782.00
UM 1811 - Electric Avenue	P36462	C/O #1: Additional work	2250: Other Outside Services	TICE ELECTRIC CO	201906	$	5,597.28
UM 1811 - Electric Avenue	P36462	C/O #1: Salem Bollard Install	2110: Other Materials	EV4 LLC	202006	$	2,875.00
UM 1811 - Electric Avenue	P36462	C/O #2: Installation of (5) ex	2110: Other Materials	EV4 LLC	202002	$	6,000.00
UM 1811 - Electric Avenue	P36462	C/O #2: Installation of equipm	2110: Other Materials	EV4 LLC	202002	$	4,850.00
UM 1811 - Electric Avenue	P36462	C/O #4-support the constructio	2250: Other Outside Services	DAVID EVANS & ASSOC INC	201904	$	3,479.68
UM 1811 - Electric Avenue	P36462	C/O #4-support the constructio	2250: Other Outside Services	DAVID EVANS & ASSOC INC	201906	$	5,194.83
UM 1811 - Electric Avenue	P36462	CABLE, 2 AWG, AL, SINGLE CABLE	2101: Storeroom Materials		201909	$	473.78
UM 1811 - Electric Avenue	P36462	CABLE, 2 AWG, AL, TRIPLEXED CA	2101: Storeroom Materials		201904	$	684.55
UM 1811 - Electric Avenue	P36462	CABLE, 2 AWG, AL, TRIPLEXED CA	2101: Storeroom Materials		201909	$	719.33
UM 1811 - Electric Avenue	P36462	CABLE, 2 AWG, AL, TRIPLEXED CA	2101: Storeroom Materials		201911	$	582.21
UM 1811 - Electric Avenue	P36462	CABLE, 2 AWG, AL, TRIPLEXED CA	2101: Storeroom Materials		201912	$	702.81
UM 1811 - Electric Avenue	P36462	CABLE, 600V, 350 KCM, AL, QUAD	2101: Storeroom Materials		201904	$	393.36
UM 1811 - Electric Avenue	P36462	CABLE, 600V, 350 KCM, AL, QUAD	2101: Storeroom Materials		201909	$	63.97
UM 1811 - Electric Avenue	P36462	CABLE, 600V, 350 KCM, AL, QUAD	2101: Storeroom Materials		201911	$	212.50
UM 1811 - Electric Avenue	P36462	CABLE, 600V, 350 KCM, AL, QUAD	2101: Storeroom Materials		201912	$	214.20
UM 1811 - Electric Avenue	P36462	CAP, INSULATED, PROTECTIVE, LO	2101: Storeroom Materials		201909	$	86.27
UM 1811 - Electric Avenue	P36462	Cellular Data Fees (1 year) -	2250: Other Outside Services	ZECO SYSTEMS INC	201904	$	960.00
UM 1811 - Electric Avenue	P36462	Cellular Data Fees (1 year) -	2250: Other Outside Services	ZECO SYSTEMS INC	201907	$	1,920.00
UM 1811 - Electric Avenue	P36462	Cellular Data Fees (1 year) -	2250: Other Outside Services	ZECO SYSTEMS INC	201912	$	(2,880.00)
UM 1811 - Electric Avenue	P36462	Charger Wrapping	2110: Other Materials	GILLESPIE DECALS INC	201912	$	1,910.00
UM 1811 - Electric Avenue	P36462	Charger Wrapping	2110: Other Materials	GILLESPIE DECALS INC	202006	$	380.00
UM 1811 - Electric Avenue	P36462	Charging Station Kit - Sunset	2250: Other Outside Services	GILLESPIE DECALS INC	201906	$	2,090.00
UM 1811 - Electric Avenue	P36462	Charging Station Kit - Sunset	2250: Other Outside Services	GILLESPIE DECALS INC	201908	$	(2,090.00)
UM 1811 - Electric Avenue	P36462	Charging Station Wrapping ABB	2250: Other Outside Services	GILLESPIE DECALS INC	201910	$	4,570.00

UM 1811 - Electric Avenue	P36462	CHARGING STATION WRAPPINGINC	2250: Other Outside Services	GILLESPIE DECALS INC	201908	$	8,280.00
UM 1811 - Electric Avenue	P36462	City of Beaverton - Pre-App fo	2401: Mileage Salary	Santhouse,Jennifer L	201906	$	6.38
UM 1811 - Electric Avenue	P36462	CO #1: Asphalt Repairs	2110: Other Materials	COAST SWEEPING SERVICES INC	202004	$	5,950.00
UM 1811 - Electric Avenue	P36462	CO #2- EV Charging Hubs	2250: Other Outside Services	DAVID EVANS & ASSOC INC	201902	$	16,500.00
UM 1811 - Electric Avenue	P36462	CO#1 - fees for demob/remob an	2214: Excavation Services	KUENZI II INC	201905	$	5,880.00
UM 1811 - Electric Avenue	P36462	CO#1 Eaton switchgear for Beav	2110: Other Materials	EV4 LLC	201910	$	35,808.60
UM 1811 - Electric Avenue	P36462	CO#1- Sunset Esplanade	2250: Other Outside Services	DAVID EVANS & ASSOC INC	201902	$	16,000.00
UM 1811 - Electric Avenue	P36462	CO#1: Additional Construction	2250: Other Outside Services	EV4 LLC	201911	$	10,850.00
UM 1811 - Electric Avenue	P36462	CO#1: Additional Construction	2250: Other Outside Services	EV4 LLC	201912	$	24,000.00
UM 1811 - Electric Avenue	P36462	CO#1: Additional Construction	2250: Other Outside Services	EV4 LLC	202002	$	150.00
UM 1811 - Electric Avenue	P36462	CO#1: Complete Redesign Due to	2110: Other Materials	EV4 LLC	201912	$	17,320.00
UM 1811 - Electric Avenue	P36462	CO#1: Complete Redesign Due to	2110: Other Materials	EV4 LLC	202003	$	11,200.00
UM 1811 - Electric Avenue	P36462	CO#1: Underground Boring	2250: Other Outside Services	EV4 LLC	201910	$	7,425.00
UM 1811 - Electric Avenue	P36462	CO#1:Additional work for const	2250: Other Outside Services	EV4 LLC	201906	$	7,750.00
UM 1811 - Electric Avenue	P36462	CO#2 ¿¿¿ Installation and materi	2250: Other Outside Services	TICE ELECTRIC CO	201905	$	6,703.63
UM 1811 - Electric Avenue	P36462	CO#2: Additional Construction	2110: Other Materials	EV4 LLC	201912	$	9,438.00
UM 1811 - Electric Avenue	P36462	CO#2:Transportation of equip f	2219: Freight/Transportation Svcs	EV4 LLC	201906	$	950.00
UM 1811 - Electric Avenue	P36462	CO#3- Hillsboro Revisions & Wi	2250: Other Outside Services	DAVID EVANS & ASSOC INC	201902	$	2,659.73
UM 1811 - Electric Avenue	P36462	CO#3- Hillsboro Revisions & Wi	2250: Other Outside Services	DAVID EVANS & ASSOC INC	201905	$	1,240.27
UM 1811 - Electric Avenue	P36462	CO#3: Civil work to demo and r	2110: Other Materials	EV4 LLC	202003	$	1,000.00
UM 1811 - Electric Avenue	P36462	CO1 C0050-16992 Cable Manageme	2250: Other Outside Services	ZECO SYSTEMS INC	201902	$	576.00
UM 1811 - Electric Avenue	P36462	CO1 C0050-16992 Cable Manageme	2250: Other Outside Services	ZECO SYSTEMS INC	201903	$	576.00
UM 1811 - Electric Avenue	P36462	CO1 C0050-16992 Cable Manageme	2250: Other Outside Services	ZECO SYSTEMS INC	201907	$	576.00
UM 1811 - Electric Avenue	P36462	CONNECTOR, ELECTRICAL, 1/2 IN	2101: Storeroom Materials		201909	$	114.07
UM 1811 - Electric Avenue	P36462	Construction and Installation	2110: Other Materials	EV4 LLC	201911	$	28,520.00
UM 1811 - Electric Avenue	P36462	Construction and Installation	2110: Other Materials	EV4 LLC	201912	$	178,580.00
UM 1811 - Electric Avenue	P36462	Construction and Installation	2110: Other Materials	EV4 LLC	202002	$	6,800.00
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201902	$	47,868.35
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201903	$	50,612.93
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201904	$	52,073.44
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201905	$	12,376.04
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201906	$	(7,124.32)
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201907	$	53,706.94
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201908	$	5,620.27
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201909	$	37,668.47
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201910	$	14,063.62
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201911	$	10,880.35
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		201912	$	(2,470.21)
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		202001	$	8,128.53
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		202002	$	4,314.91
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		202003	$	740.89
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		202004	$	173.50
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		202005	$	(202.33)
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		202006	$	850.43
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		202007	$	10.61

UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		202008	$	12.97
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		202009	$	8.65
UM 1811 - Electric Avenue	P36462	Construction Overhead	5303: Construction Overhead		202101	$	361.87
UM 1811 - Electric Avenue	P36462	COVER, WILDLIFE, POLYMER CUTOU	2101: Storeroom Materials		201909	$	32.82
UM 1811 - Electric Avenue	P36462	CUTOUT, FUSED/TD, DROPOUT, 15	2101: Storeroom Materials		201909	$	131.00
UM 1811 - Electric Avenue	P36462	Eastport Plaza Landscape	2213: Landscape Services	PACIFIC LANDSCAPE MGMT INC	201911	$	3,785.00
UM 1811 - Electric Avenue	P36462	Eastport Plaza Paving	2110: Other Materials	COAST SWEEPING SERVICES INC	202001	$	3,765.00
UM 1811 - Electric Avenue	P36462	Eastport Plaza Paving	2110: Other Materials	COAST SWEEPING SERVICES INC	201911	$	6,500.00
UM 1811 - Electric Avenue	P36462	ELBOW, LOADBREAK, 200 A, 2 AL,	2101: Storeroom Materials		201904	$	129.30
UM 1811 - Electric Avenue	P36462	ELBOW, LOADBREAK, 200 A, 2 AL,	2101: Storeroom Materials		201909	$	451.46
UM 1811 - Electric Avenue	P36462	ELBOW, LOADBREAK, 200 A, 2 AL,	2101: Storeroom Materials		201911	$	133.52
UM 1811 - Electric Avenue	P36462	ELBOW, LOADBREAK, 200 A, 2 AL,	2101: Storeroom Materials		201912	$	134.78
UM 1811 - Electric Avenue	P36462	Elect. Construction Svcs for S	2250: Other Outside Services	EV4 LLC	201904	$	90,315.00
UM 1811 - Electric Avenue	P36462	Elect. Construction Svcs for S	2250: Other Outside Services	EV4 LLC	201906	$	2,285.00
UM 1811 - Electric Avenue	P36462	Electric Ave Expansion, Site #	2450: Other Busineses Expense	Lohf,Ariana	201907	$	3,325.00
UM 1811 - Electric Avenue	P36462	Electric Ave Milwaukie Bollard	2110: Other Materials	Lohf,Ariana	201904	$	880.85
UM 1811 - Electric Avenue	P36462	Electric Ave Site #2 testing o	2250: Other Outside Services	Lohf,Ariana	201907	$	20.00
UM 1811 - Electric Avenue	P36462	Electric Ave site sub-surface	2250: Other Outside Services	HAHN AND ASSOCIATES INC	201905	$	5,437.39
UM 1811 - Electric Avenue	P36462	Electric Ave: Reflective tape	2450: Other Busineses Expense	Reiersgard,Laura M	202002	$	38.91
UM 1811 - Electric Avenue	P36462	Electric Avenue Construction D	2250: Other Outside Services	EV4 LLC	201907	$	59,000.00
UM 1811 - Electric Avenue	P36462	Electric Avenue Construction D	2250: Other Outside Services	EV4 LLC	201908	$	29,500.00
UM 1811 - Electric Avenue	P36462	Electric Avenue Construction D	2250: Other Outside Services	EV4 LLC	201909	$	29,500.00
UM 1811 - Electric Avenue	P36462	Electric Avenue Layout Designs	2250: Other Outside Services	EV4 LLC	201906	$	16,000.00
UM 1811 - Electric Avenue	P36462	Electrical Construction Servic	2250: Other Outside Services	TICE ELECTRIC CO	201903	$	63,777.00
UM 1811 - Electric Avenue	P36462	Electrical Construction Servic	2250: Other Outside Services	TICE ELECTRIC CO	201905	$	10,000.00
UM 1811 - Electric Avenue	P36462	Electrical Construction Servic	5404: Accrual	TICE ELECTRIC CO	201902	$	83,712.00
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201811	$	89.89
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201812	$	(1.39)
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201901	$	92.62
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201902	$	(13.28)
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201903	$	(4.87)
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201904	$	299.77
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201905	$	220.08
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201906	$	115.63
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201907	$	1,389.06
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201908	$	3,446.59
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201909	$	629.12
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201910	$	153.66
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201911	$	6,546.16
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		201912	$	2,205.30
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202001	$	1,713.78
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202002	$	938.96
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202003	$	494.75
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202004	$	393.41
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202005	$	509.24

UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202006	$ 283.94
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202007	$ (95.27)
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202008	$ 11.44
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202009	$ 18.52
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202010	$ (23.08)
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202011	$ 66.90
UM 1811 - Electric Avenue	P36462	Employee Benefits Overhead	5105: Employee Benefits Overhead		202012	$ (6.37)
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201811	$ 2.90
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201812	$ 0.19
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201901	$ 1.86
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201902	$ 0.13
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201904	$ 9.48
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201905	$ 6.96
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201906	$ 6.58
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201907	$ 47.43
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201908	$ 123.78
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201909	$ 10.99
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201910	$ 3.49
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201911	$ 212.45
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		201912	$ 84.77
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202001	$ 30.03
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202002	$ 35.99
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202003	$ 22.24
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202004	$ 23.47
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202005	$ 18.72
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202006	$ 13.20
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202007	$ (9.56)
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202008	$ 1.96
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202009	$ (0.38)
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202010	$ (1.36)
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202011	$ 2.85
UM 1811 - Electric Avenue	P36462	Employee support Offset	5102: Employee support Offset		202012	$ (0.68)
UM 1811 - Electric Avenue	P36462	EV Charging Station Designs an	2250: Other Outside Services	HARRIS MASSEY HERINCKX ADV	201904	$ 5,560.00
UM 1811 - Electric Avenue	P36462	EV Charging station wrapping M	2250: Other Outside Services	Rigby,Anna-Katharina	201904	$ 8,710.00
UM 1811 - Electric Avenue	P36462	EV Charging station wraps - Mi	2250: Other Outside Services	Rigby,Anna-Katharina	201904	$ 3,790.00
UM 1811 - Electric Avenue	P36462	EXCAVATION - F6081692 M2543279	2214: Excavation Services	EXTREME EXCAVATING INC	201906	$ 26,408.00
UM 1811 - Electric Avenue	P36462	EXCAVATION - F6740259 M2640092	2214: Excavation Services	KUENZI II INC	201904	$ 16,020.00
UM 1811 - Electric Avenue	P36462	EXCAVATION - F6740259 M2640092	2214: Excavation Services	KUENZI II INC	201905	$ 1,780.00
UM 1811 - Electric Avenue	P36462	Field Services Start Up	2250: Other Outside Services	CONSOLIDATED ELECT DISTRIBU	201902	$ 2,469.62
UM 1811 - Electric Avenue	P36462	Field Services Start Up	2250: Other Outside Services	CONSOLIDATED ELECT DISTRIBU	201903	$ 3,130.38
UM 1811 - Electric Avenue	P36462	Final files and production of	2250: Other Outside Services	HARRIS MASSEY HERINCKX ADV	201904	$ 600.00
UM 1811 - Electric Avenue	P36462	FLAGGING INVOICE 27721	2210: Flagging Services	Somerville,Jennifer L	202002	$ 241.00
UM 1811 - Electric Avenue	P36462	FOOTING, PRECAST, POLE, 20 IN	2101: Storeroom Materials		201901	$ 846.00
UM 1811 - Electric Avenue	P36462	Ground Freight & Handling	2250: Other Outside Services	ZECO SYSTEMS INC	201902	$ 1,727.55
UM 1811 - Electric Avenue	P36462	Ground Freight & Handling	2250: Other Outside Services	ZECO SYSTEMS INC	201903	$ 1,727.55

UM 1811 - Electric Avenue	P36462	Ground Freight & Handling	2250: Other Outside Services	ZECO SYSTEMS INC	201907	$	1,779.90
UM 1811 - Electric Avenue	P36462	Ground Freight & Handling	2250: Other Outside Services	ZECO SYSTEMS INC	201909	$	3,490.00
UM 1811 - Electric Avenue	P36462	High Powered Charger Dispenser	2250: Other Outside Services	ZECO SYSTEMS INC	201902	$	49,898.00
UM 1811 - Electric Avenue	P36462	High Powered Charger Dispenser	2250: Other Outside Services	ZECO SYSTEMS INC	201903	$	49,898.00
UM 1811 - Electric Avenue	P36462	High Powered Charger Dispenser	2250: Other Outside Services	ZECO SYSTEMS INC	201904	$	49,898.00
UM 1811 - Electric Avenue	P36462	High Powered Charger Dispenser	2250: Other Outside Services	ZECO SYSTEMS INC	201907	$	149,694.00
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201811	$	14.14
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201812	$	0.01
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201901	$	12.60
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201902	$	(10.41)
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201903	$	2.25
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201904	$	29.98
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201905	$	30.39
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201906	$	12.31
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201907	$	170.37
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201908	$	456.45
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201909	$	74.18
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201910	$	52.45
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201911	$	922.21
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		201912	$	259.36
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202001	$	195.30
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202002	$	188.41
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202003	$	(108.68)
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202004	$	86.19
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202005	$	89.87
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202006	$	31.35
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202007	$	13.12
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202008	$	22.41
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202009	$	(581.26)
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202010	$	592.70
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202011	$	16.97
UM 1811 - Electric Avenue	P36462	Incentives Overhead	5103: Incentives Overhead		202012	$	152.36
UM 1811 - Electric Avenue	P36462	INDICATOR, FAULT, VARIABLE TRI	2101: Storeroom Materials		201911	$	518.79
UM 1811 - Electric Avenue	P36462	INDICATOR, FAULT, VARIABLE TRI	2101: Storeroom Materials		201912	$	532.23
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201811	$	14.94
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201812	$	1.46
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201901	$	11.52
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201902	$	0.53
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201903	$	0.60
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201904	$	52.58
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201905	$	33.94
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201906	$	36.18
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201907	$	272.13
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201908	$	650.61
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201909	$	226.59

UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201910	$ 2.51
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201911	$ 1,241.30
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		201912	$ 393.10
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202001	$ 218.40
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202002	$ 216.26
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202003	$ 98.27
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202004	$ 81.11
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202005	$ 86.36
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202006	$ 111.64
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202007	$ (9.14)
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202008	$ (8.31)
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202009	$ 14.19
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202010	$ (26.10)
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202011	$ 20.65
UM 1811 - Electric Avenue	P36462	Injuries Overhead	5107: Injuries Overhead		202012	$ (125.71)
UM 1811 - Electric Avenue	P36462	Installation - Sunset Transit	2250: Other Outside Services	GILLESPIE DECALS INC	201906	$ 1,035.00
UM 1811 - Electric Avenue	P36462	Installation - Sunset Transit	2250: Other Outside Services	GILLESPIE DECALS INC	201908	$ (1,035.00)
UM 1811 - Electric Avenue	P36462	Installation ¿¿¿ Milwaukie	2250: Other Outside Services	GILLESPIE DECALS INC	201905	$ 1,015.00
UM 1811 - Electric Avenue	P36462	JUNCT, PRI, 4 POS, 15KV, 200A,	2101: Storeroom Materials		201909	$ 472.70
UM 1811 - Electric Avenue	P36462	KIT, SEALING, CABLE ACCESSORY,	2101: Storeroom Materials		201904	$ 38.70
UM 1811 - Electric Avenue	P36462	KIT, SEALING, CABLE ACCESSORY,	2101: Storeroom Materials		201909	$ 136.25
UM 1811 - Electric Avenue	P36462	KIT, SEALING, CABLE ACCESSORY,	2101: Storeroom Materials		201911	$ 38.72
UM 1811 - Electric Avenue	P36462	KIT, SEALING, CABLE ACCESSORY,	2101: Storeroom Materials		201912	$ 40.13
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201811	$ 0.03
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201812	$ 0.01
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201901	$ 0.01
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201904	$ 0.08
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201905	$ 0.02
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201906	$ 0.01
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201907	$ 0.21
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201908	$ 0.52
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201909	$ 0.17
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201910	$ (0.03)
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201911	$ 1.04
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		201912	$ 1.90
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202001	$ 0.68
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202002	$ 0.31
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202003	$ 0.43
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202004	$ 0.44
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202005	$ 0.32
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202006	$ 0.09
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202007	$ (0.10)
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202008	$ 0.15
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202009	$ (0.03)
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202010	$ 0.03

UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202011	$	0.08
UM 1811 - Electric Avenue	P36462	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202012	$	0.02
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201811	$	10.40
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201812	$	(0.19)
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201901	$	8.72
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201902	$	(0.46)
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201903	$	(0.09)
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201904	$	39.31
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201905	$	27.34
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201906	$	9.99
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201907	$	158.51
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201908	$	393.98
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201909	$	163.84
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201910	$	36.36
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201911	$	759.26
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		201912	$	210.78
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202001	$	191.69
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202002	$	141.81
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202003	$	79.12
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202004	$	73.65
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202005	$	27.80
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202006	$	49.23
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202007	$	4.58
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202008	$	3.73
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202009	$	0.94
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202010	$	5.06
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202011	$	(12.81)
UM 1811 - Electric Avenue	P36462	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202012	$	5.28
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Uni		201811	$	0.85
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201812	$	(0.02)
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201901	$	0.60
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201902	$	0.01
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201903	$	0.01
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201904	$	3.30
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201905	$	2.18
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201906	$	1.33
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201907	$	13.32
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201908	$	32.14
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201909	$	14.20
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201910	$	3.48
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201911	$	58.94
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		201912	$	19.69
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202001	$	14.10
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202002	$	11.11
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202003	$	4.72

UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor	202004	$	4.71
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor	202005	$	3.72
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor	202006	$	2.84
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor	202007	$	(0.88)
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor	202008	$	(0.41)
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor	202009	$	(0.51)
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor	202010	$	(0.17)
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor	202011	$	(0.26)
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor	202012	$	0.17
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201811	$	0.04
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201901	$	0.02
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201902	$	0.02
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201903	$	(0.01)
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201904	$	19.33
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201905	$	3.91
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201906	$	3.18
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201907	$	27.57
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201908	$	8.78
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201909	$	88.31
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201910	$	24.04
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201911	$	14.68
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	201912	$	41.88
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202001	$	1.06
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202002	$	0.94
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202003	$	0.38
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202004	$	5.05
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202005	$	(0.07)
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202006	$	0.28
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202008	$	0.04
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202009	$	(0.17)
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202010	$	0.06
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202011	$	1.10
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor	202012	$	0.28
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time la	201811	$	0.08
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	201904	$	0.05
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	201905	$	0.01
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	201906	$	0.08
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	201907	$	0.62
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	201908	$	2.26
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	201909	$	0.66
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	201910	$	(0.09)
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	201911	$	3.04
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	201912	$	0.88
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	202006	$	0.43
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor	202007	$	0.62

UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202008	$ 0.51
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202009	$ 0.05
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202010	$ 0.06
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202011	$ 0.17
UM 1811 - Electric Avenue	P36462	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202012	$ (0.02)
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		201904	$ 1.63
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		201905	$ 0.37
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		201906	$ 0.58
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		201907	$ 2.13
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		201908	$ 0.62
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		201909	$ 7.46
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		201910	$ 2.87
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		201911	$ 1.12
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		201912	$ 4.98
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202004	$ 0.15
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202005	$ (0.02)
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202006	$ 0.01
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202007	$ (0.01)
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202008	$ (0.02)
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202009	$ 0.06
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202010	$ (0.01)
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202011	$ 0.05
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		201904	$ 0.07
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		201906	$ 0.01
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		201907	$ 0.06
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		201908	$ 0.01
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		201909	$ 0.20
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		201910	$ (0.01)
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		201911	$ 0.06
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		201912	$ 0.05
UM 1811 - Electric Avenue	P36462	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		202009	$ 0.01
UM 1811 - Electric Avenue	P36462	Land Use, Zoning, Permitting,	2250: Other Outside Services	DAVID EVANS & ASSOC INC	201902	$ 48,000.00
UM 1811 - Electric Avenue	P36462	Landscape Restoration at Wilso	2110: Other Materials	PACIFIC LANDSCAPE MGMT INC	201912	$ 18,498.00
UM 1811 - Electric Avenue	P36462	Landscape Restoration work	2110: Other Materials	PACIFIC LANDSCAPE MGMT INC	202001	$ 1,207.00
UM 1811 - Electric Avenue	P36462	Landscape Restoration work for	2110: Other Materials	PACIFIC LANDSCAPE MGMT INC	202004	$ 13,571.00
UM 1811 - Electric Avenue	P36462	Level 2 BTC Power Outdoor Rate	2250: Other Outside Services	ZECO SYSTEMS INC	201902	$ 2,040.00
UM 1811 - Electric Avenue	P36462	Level 2 BTC Power Outdoor Rate	2250: Other Outside Services	ZECO SYSTEMS INC	201903	$ 2,040.00
UM 1811 - Electric Avenue	P36462	Level 2 BTC Power Outdoor Rate	2250: Other Outside Services	ZECO SYSTEMS INC	201904	$ 2,040.00
UM 1811 - Electric Avenue	P36462	Level 2 BTC Power Outdoor Rate	2250: Other Outside Services	ZECO SYSTEMS INC	201907	$ 6,120.00
UM 1811 - Electric Avenue	P36462	Lot Striping/Stencil/Signage	2110: Other Materials	COAST SWEEPING SERVICES INC	202001	$ 2,999.00
UM 1811 - Electric Avenue	P36462	Lot Striping/Stencil/Signage/S	2110: Other Materials	COAST SWEEPING SERVICES INC	202002	$ 10,326.00
UM 1811 - Electric Avenue	P36462	LUMINAIRE, ACORN, 66WLED, 120-	2101: Storeroom Materials		201901	$ 2,110.66
UM 1811 - Electric Avenue	P36462	Materials	5302: Materials		201901	$ 858.97
UM 1811 - Electric Avenue	P36462	Materials	5302: Materials		201904	$ 264.01
UM 1811 - Electric Avenue	P36462	Materials	5302: Materials		201909	$ 598.29

UM 1811 - Electric Avenue	P36462	Materials	5302: Materials		201911	$	366.23
UM 1811 - Electric Avenue	P36462	Materials	5302: Materials		201912	$	242.23
UM 1811 - Electric Avenue	P36462	Materials	5302: Materials		202002	$	117.87
UM 1811 - Electric Avenue	P36462	Materials	5302: Materials		202009	$	(10.08)
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201811	$	9.66
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201812	$	0.11
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201901	$	4.09
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201902	$	496.31
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201903	$	434.09
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201904	$	520.11
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201905	$	125.65
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201906	$	(89.19)
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201907	$	554.88
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201908	$	259.37
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201909	$	406.62
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201910	$	99.36
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201911	$	489.19
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		201912	$	100.01
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202001	$	125.04
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202002	$	72.17
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202003	$	29.48
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202004	$	20.95
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202005	$	24.96
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202006	$	20.74
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202007	$	(3.42)
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202008	$	2.87
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202009	$	2.65
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202010	$	0.01
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202011	$	4.67
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202012	$	(0.74)
UM 1811 - Electric Avenue	P36462	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202101	$	2.48
UM 1811 - Electric Avenue	P36462	Non PGE Labor Overtime Time	1602: Non PGE Labor Overtime Time		201911	$	332.86
UM 1811 - Electric Avenue	P36462	Non PGE Labor Straight Time	1502: Non PGE Labor Straight Time		201911	$	2,624.86
UM 1811 - Electric Avenue	P36462	Non PGE Labor Straight Time	1502: Non PGE Labor Straight Time		202002	$	2,731.96
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201811	$	10.65
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201812	$	0.17
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201901	$	7.30
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201902	$	0.12
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201903	$	0.56
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201904	$	90.82
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201905	$	70.36
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201906	$	37.24
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201907	$	278.33
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201908	$	552.06
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201909	$	486.16

UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201910	$	114.00
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201911	$	976.43
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		201912	$	519.25
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202001	$	146.29
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202002	$	115.16
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202003	$	123.57
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202004	$	62.26
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202005	$	87.00
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202006	$	25.36
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202007	$	(11.10)
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202008	$	5.35
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202009	$	(21.96)
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202010	$	(6.12)
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202011	$	7.03
UM 1811 - Electric Avenue	P36462	Non-Labor Allocation	5599: Non-Labor Allocation		202012	$	1.31
UM 1811 - Electric Avenue	P36462	Other Materials	2110: Other Materials		201911	$	27,327.00
UM 1811 - Electric Avenue	P36462	Other Materials	2110: Other Materials		201912	$	9,109.00
UM 1811 - Electric Avenue	P36462	Other Materials	2110: Other Materials		202002	$	9,109.00
UM 1811 - Electric Avenue	P36462	Other Outside Services	2250: Other Outside Services		201911	$	675.50
UM 1811 - Electric Avenue	P36462	Other Outside Services	2250: Other Outside Services		202002	$	777.00
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201811	$	1.68
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201812	$	0.02
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201901	$	0.97
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201902	$	141.03
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201903	$	102.84
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201904	$	110.26
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201905	$	29.13
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201906	$	(23.28)
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201907	$	131.16
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201908	$	61.63
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201909	$	93.18
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201910	$	30.80
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201911	$	117.04
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		201912	$	22.68
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202001	$	0.54
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202002	$	0.31
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202003	$	0.13
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202004	$	0.10
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202005	$	0.09
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202006	$	0.10
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202007	$	(0.02)
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202008	$	0.02
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202009	$	0.01
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202011	$	0.02
UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202012	$	(0.01)

UM 1811 - Electric Avenue	P36462	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202101	$	(0.15)
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201811	$	2.65
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201812	$	0.02
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201901	$	1.61
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201902	$	0.04
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201904	$	6.93
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201905	$	5.10
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201906	$	2.82
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201907	$	31.70
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201908	$	80.67
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201909	$	15.46
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201910	$	3.74
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201911	$	154.99
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		201912	$	54.25
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202001	$	27.17
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202002	$	24.84
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202003	$	10.08
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202004	$	8.11
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202005	$	10.04
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202006	$	5.59
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202007	$	(0.99)
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202008	$	1.19
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202009	$	1.14
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202010	$	0.14
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202011	$	1.72
UM 1811 - Electric Avenue	P36462	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202012	$	(0.15)
UM 1811 - Electric Avenue	P36462	Ovetime Union Planned	1402: Ovetime Union Planned		201909	$	1,856.24
UM 1811 - Electric Avenue	P36462	Parking Signage	2110: Other Materials	COAST SWEEPING SERVICES INC	202002	$	799.00
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201811	$	28.55
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201812	$	(0.15)
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201901	$	25.65
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201902	$	0.35
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201903	$	(1.95)
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201904	$	100.15
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201905	$	71.58
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201906	$	34.74
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201907	$	454.74
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201908	$	1,123.58
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201909	$	326.05
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201910	$	83.57
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201911	$	2,023.30
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		201912	$	687.90
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202001	$	472.00
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202002	$	498.34
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202003	$	280.14

UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202004	$	119.38
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202005	$	122.63
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202006	$	52.85
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202007	$	(23.30)
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202008	$	(10.16)
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202009	$	(104.26)
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202010	$	41.83
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202011	$	(36.04)
UM 1811 - Electric Avenue	P36462	Payroll Taxes	5106: Payroll Taxes		202012	$	(12.33)
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201811	$	21.60
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201812	$	0.20
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201901	$	12.99
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201902	$	0.48
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201903	$	(0.04)
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201904	$	56.05
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201905	$	41.53
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201906	$	23.02
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201907	$	257.48
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201908	$	654.77
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201909	$	125.49
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201910	$	30.01
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201911	$	1,256.87
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		201912	$	438.52
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202001	$	276.30
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202002	$	255.69
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202003	$	104.62
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202004	$	83.86
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202005	$	102.94
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202006	$	57.55
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202007	$	(9.28)
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202008	$	12.33
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202009	$	11.94
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202010	$	1.37
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202011	$	17.21
UM 1811 - Electric Avenue	P36462	Pension Service Costs	5111: Pension Service Costs		202012	$	(1.07)
UM 1811 - Electric Avenue	P36462	PHOTOCONTROL,EXTENDED LIFE ELE	2101: Storeroom Materials		201901	$	20.32
UM 1811 - Electric Avenue	P36462	POLE,14FT,ALUMINUM. PACKAGED I	2101: Storeroom Materials		201901	$	1,509.08
UM 1811 - Electric Avenue	P36462	Project Management	2250: Other Outside Services	DAVID EVANS & ASSOC INC	201902	$	975.00
UM 1811 - Electric Avenue	P36462	RCCB to Beaverton Electric Ave	2401: Mileage Salary	Trostle,Kelsey M	201908	$	11.60
UM 1811 - Electric Avenue	P36462	RCCB to Eastport Electric Aven	2401: Mileage Salary	Trostle,Kelsey M	201908	$	13.92
UM 1811 - Electric Avenue	P36462	Reclassification	5408: Reclassification		202003	$	6,011.04
UM 1811 - Electric Avenue	P36462	Salem Capitol Building for Dee	2401: Mileage Salary	Trostle,Kelsey M	201909	$	55.68
UM 1811 - Electric Avenue	P36462	Salem EA: parking stall, ADA r	2250: Other Outside Services	EV4 LLC	202006	$	6,750.00
UM 1811 - Electric Avenue	P36462	SC, TCC, AF System Studies	2250: Other Outside Services	CONSOLIDATED ELECT DISTRIBU	201902	$	7,200.00
UM 1811 - Electric Avenue	P36462	Site #1 & 2 - Milwaukie & Hill	2250: Other Outside Services	CONSOLIDATED ELECT DISTRIBU	201902	$	65,350.00

UM 1811 - Electric Avenue	P36462	Site #1 Milwaukie- stripping s	2250: Other Outside Services	Lohf,Ariana	201907	$	1,715.00
UM 1811 - Electric Avenue	P36462	Site #2 Hillsboro - landscapin	2250: Other Outside Services	Lohf,Ariana	201907	$	5,206.65
UM 1811 - Electric Avenue	P36462	Site #3 Eastport Plaza Shoppin	2250: Other Outside Services	EV4 LLC	201910	$	100,800.00
UM 1811 - Electric Avenue	P36462	Site #3 Eastport Plaza Shoppin	2250: Other Outside Services	EV4 LLC	201911	$	11,200.00
UM 1811 - Electric Avenue	P36462	Site #4 Wilsonville Public Lib	2250: Other Outside Services	EV4 LLC	201912	$	111,800.00
UM 1811 - Electric Avenue	P36462	Site #4 Wilsonville Public Lib	2250: Other Outside Services	EV4 LLC	202002	$	200.00
UM 1811 - Electric Avenue	P36462	Sky Commissioning	2250: Other Outside Services	ZECO SYSTEMS INC	201904	$	750.00
UM 1811 - Electric Avenue	P36462	Sky Commissioning	2250: Other Outside Services	ZECO SYSTEMS INC	201907	$	1,500.00
UM 1811 - Electric Avenue	P36462	Storeroom Materials	2101: Storeroom Materials		201904	$	143.64
UM 1811 - Electric Avenue	P36462	Storeroom Materials	2101: Storeroom Materials		201907	$	0.01
UM 1811 - Electric Avenue	P36462	Storeroom Materials	2101: Storeroom Materials		201909	$	411.92
UM 1811 - Electric Avenue	P36462	Storeroom Materials	2101: Storeroom Materials		201911	$	441.80
UM 1811 - Electric Avenue	P36462	Storeroom Materials	2101: Storeroom Materials		201912	$	184.09
UM 1811 - Electric Avenue	P36462	Storeroom Materials	2101: Storeroom Materials		202002	$	620.39
UM 1811 - Electric Avenue	P36462	Storeroom Materials	2101: Storeroom Materials		202009	$	(0.01)
UM 1811 - Electric Avenue	P36462	Storeroom Materials	2101: Storeroom Materials		202011	$	0.01
UM 1811 - Electric Avenue	P36462	Straight Time Labor Hourly	1103: Straight Time Labor Hourly		201811	$	264.64
UM 1811 - Electric Avenue	P36462	Straight Time Labor Hourly	1103: Straight Time Labor Hourly		201901	$	198.48
UM 1811 - Electric Avenue	P36462	Straight Time Labor Hourly	1103: Straight Time Labor Hourly		201905	$	634.60
UM 1811 - Electric Avenue	P36462	Straight Time Labor Hourly	1103: Straight Time Labor Hourly		201906	$	95.19
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		201906	$	235.88
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		201907	$	3,863.01
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		201908	$	9,926.37
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		201909	$	806.33
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		201910	$	15,436.85
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		201911	$	4,347.48
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		201912	$	4,532.21
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		202001	$	4,242.59
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		202002	$	3,595.62
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		202003	$	1,832.67
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		202004	$	1,472.38
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		202005	$	1,738.23
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		202006	$	490.67
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		202007	$	53.19
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		202008	$	53.19
UM 1811 - Electric Avenue	P36462	Straight Time Labor Salary	1101: Straight Time Labor Salary		202009	$	53.19
UM 1811 - Electric Avenue	P36462	Straight Time Labor Union	1102: Straight Time Labor Union		201904	$	822.52
UM 1811 - Electric Avenue	P36462	Straight Time Labor Union	1102: Straight Time Labor Union		201909	$	816.52
UM 1811 - Electric Avenue	P36462	Straight Time Labor Union	1102: Straight Time Labor Union		201911	$	104.31
UM 1811 - Electric Avenue	P36462	Straight Time Labor Union	1102: Straight Time Labor Union		201912	$	1,632.66
UM 1811 - Electric Avenue	P36462	Sunset Esplanade Site Visualiz	2250: Other Outside Services	DAVID EVANS & ASSOC INC	201902	$	1,873.60
UM 1811 - Electric Avenue	P36462	Switchgear, system studies & c	2110: Other Materials	EV4 LLC	201911	$	35,808.60
UM 1811 - Electric Avenue	P36462	Switchgear, system studies & c	2110: Other Materials	EV4 LLC	201912	$	35,808.59
UM 1811 - Electric Avenue	P36462	Terra 53CJ 50kw Dual Chargers	2250: Other Outside Services	ZECO SYSTEMS INC	202001	$	58,035.00
UM 1811 - Electric Avenue	P36462	USE CR ON NEXT INV. C50 18352	2250: Other Outside Services	GILLESPIE DECALS INC	201912	$	(680.00)

UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201811	$ 46.11
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201812	$ 2.09
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201901	$ 32.73
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201902	$ 0.45
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201903	$ 2.13
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201904	$ 148.33
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201905	$ 105.40
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201906	$ 92.43
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201907	$ 719.05
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201908	$ 1,828.01
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201909	$ 356.69
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201910	$ 82.03
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201911	$ 3,501.15
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		201912	$ 1,295.62
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202001	$ 696.33
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202002	$ 587.33
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202003	$ 366.06
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202004	$ 204.72
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202005	$ 455.52
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202006	$ 70.36
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202007	$ (47.62)
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202008	$ 10.12
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202009	$ 29.27
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202010	$ 12.39
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202011	$ 217.40
UM 1811 - Electric Avenue	P36462	Vacation Overhead	5104: Vacation Overhead		202012	$ (257.30)
UM 1811 - Electric Avenue	P36462	Willsonville EA City Council P	2401: Mileage Salary	Trostle,Kelsey M	201911	$ 4.64
UM 1811 - Electric Avenue	P36462	WIRE, ELECTRICAL, 3 CONDUCTOR,	2101: Storeroom Materials		201901	$ 34.85
Electric Island	P36921	Flagging Services	2210: Flagging Services	NW TRAFFIC CONTROL INC	202002	$ 197.50
Electric Island	P36921	Other Outside Services	2250: Other Outside Services	DAIMLER NORTH AMERICA COR	202010	$ 543,901.00
Electric Island	P36921	Other Outside Services	2250: Other Outside Services	DAIMLER TRUCKS NORTH AMER	202101	$ 651,824.00
Electric Island	P36921	Other Taxes & Governmental Fees	2950: Other Taxes & Governmental Fees	CITY OF PORTLAND	202006	$ 1,159.84
Electric Island	P36921	Accrual	5404: Accrual		202009	$ 543,900.00
Electric Island	P36921	Accrual	5404: Accrual		202010	$ (543,900.00)
Electric Island	P36921	Accrual	5404: Accrual		202012	$ 619,324.00
Electric Island	P36921	Accrual	5404: Accrual		202101	$ (619,324.00)
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202001	$ 0.87
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202002	$ 7.06
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202003	$ 26.08
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202004	$ 42.24
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202005	$ 42.45
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202006	$ 55.28
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202007	$ 57.12
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202008	$ 62.98
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202009	$ 63.45

Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202010	$ 1,124.84
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202011	$ 2,194.08
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202012	$ 2,187.92
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202101	$ 2,823.30
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202102	$ 3,413.62
Electric Island	P36921	AFUDC debt charge	5001: AFUDC Debt		202103	$ 3,416.11
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202001	$ 1.75
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202002	$ 14.23
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202003	$ 52.27
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202004	$ 65.84
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202005	$ 58.06
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202006	$ 156.34
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202007	$ 113.38
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202008	$ 124.56
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202009	$ 122.36
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202010	$ 2,197.43
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202011	$ 4,263.40
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202012	$ 4,293.31
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202101	$ 5,344.42
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202102	$ 6,741.70
Electric Island	P36921	AFUDC equity charge	5002: AFUDC Equity		202103	$ 6,741.03
Electric Island	P36921	CABLE, 600V, 750 KCMIL, AL, QU	2101: Storeroom Materials		202003	$ 4,821.26
Electric Island	P36921	Construction Overhead	5303: Construction Overhead		202001	$ 278.00
Electric Island	P36921	Construction Overhead	5303: Construction Overhead		202002	$ 1,595.91
Electric Island	P36921	Construction Overhead	5303: Construction Overhead		202003	$ 2,282.42
Electric Island	P36921	Construction Overhead	5303: Construction Overhead		202004	$ 1,446.85
Electric Island	P36921	Construction Overhead	5303: Construction Overhead		202007	$ 2,074.27
Electric Island	P36921	Construction Overhead	5303: Construction Overhead		202010	$ 561,011.63
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202001	$ 126.78
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202002	$ 612.49
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202003	$ 788.63
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202004	$ 24.57
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202005	$ (19.16)
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202006	$ 47.85
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202007	$ 32.51
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202008	$ (1.82)
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202009	$ 0.16
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202010	$ (8.34)
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202011	$ 19.49
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202012	$ (2.00)
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202101	$ 297.37
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202102	$ 201.09
Electric Island	P36921	Employee Benefits Overhead	5105: Employee Benefits Overhead		202103	$ 51.02
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202001	$ 2.22
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202002	$ 16.20

Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202003	$	24.41
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202004	$	6.15
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202005	$	0.43
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202006	$	3.00
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202007	$	(1.35)
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202008	$	0.55
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202009	$	(0.39)
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202010	$	(0.50)
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202011	$	0.92
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202012	$	(0.23)
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202101	$	16.54
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202102	$	(3.33)
Electric Island	P36921	Employee support Offset	5102: Employee support Offset		202103	$	0.79
Electric Island	P36921	Flagging Services	2210: Flagging Services		202002	$	121.05
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202001	$	14.45
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202002	$	92.47
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202003	$	26.58
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202004	$	24.87
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202005	$	12.40
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202006	$	5.22
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202007	$	12.66
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202008	$	7.77
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202009	$	(220.89)
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202010	$	224.44
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202011	$	5.69
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202012	$	57.70
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202101	$	69.00
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202102	$	(2.23)
Electric Island	P36921	Incentives Overhead	5103: Incentives Overhead		202103	$	56.70
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202001	$	16.15
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202002	$	105.01
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202003	$	137.66
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202004	$	10.50
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202005	$	(4.08)
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202006	$	31.12
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202007	$	9.41
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202008	$	(4.34)
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202009	$	4.18
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202010	$	(9.82)
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202011	$	6.76
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202012	$	(47.53)
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202101	$	32.79
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202102	$	30.82
Electric Island	P36921	Injuries Overhead	5107: Injuries Overhead		202103	$	25.26
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202001	$	0.05

Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202002	$	0.24
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202003	$	0.44
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202004	$	0.12
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202005	$	(0.01)
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202006	$	0.01
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202008	$	0.05
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202009	$	(0.02)
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202010	$	0.02
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202011	$	0.01
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202012	$	0.01
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202101	$	0.18
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202102	$	0.18
Electric Island	P36921	Labor Allocation - Hourly OT	5506: Allocated Hourly Overtime labor		202103	$	(0.03)
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202001	$	14.18
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202002	$	82.59
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202003	$	116.83
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202004	$	12.42
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202005	$	(18.48)
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202006	$	10.40
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202007	$	12.30
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202008	$	0.45
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202009	$	(1.04)
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202010	$	1.99
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202011	$	(5.49)
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202012	$	1.74
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202101	$	25.56
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202102	$	20.25
Electric Island	P36921	Labor Allocation - ST Salary	5501: Allocated ST SALARY Labor		202103	$	10.44
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Unio		202001	$	1.04
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202002	$	6.49
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202003	$	8.84
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202004	$	0.66
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202005	$	(0.68)
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202006	$	0.52
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202007	$	0.63
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202008	$	(0.24)
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202009	$	(0.28)
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202010	$	(0.04)
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202011	$	(0.38)
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202012	$	0.09
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202101	$	1.84
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202102	$	1.45
Electric Island	P36921	Labor Allocation-ST Hrly NonUn	5503: Allocated straight time HOURLY Non-Union labor		202103	$	0.76
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202001	$	0.08
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202002	$	16.02

Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202003	$	42.82
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202004	$	2.00
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202005	$	(9.55)
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202006	$	2.31
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202007	$	10.48
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202008	$	0.81
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202009	$	(1.11)
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202010	$	1.26
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202011	$	(4.38)
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202012	$	1.70
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202101	$	0.02
Electric Island	P36921	Labor Allocation-ST Hrly Union	5502: Allocated straight time UNION labor		202102	$	0.01
Electric Island	P36921	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time la		202006	$	0.16
Electric Island	P36921	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202007	$	0.24
Electric Island	P36921	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202008	$	0.19
Electric Island	P36921	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202009	$	0.02
Electric Island	P36921	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202010	$	0.02
Electric Island	P36921	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202011	$	0.06
Electric Island	P36921	Labor Allocation-ST Temporary	5509: Allocated PGE Temporary Straight Time labor		202102	$	0.05
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202002	$	0.59
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202003	$	1.60
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202004	$	(0.28)
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202005	$	(0.33)
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202006	$	0.16
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202007	$	0.12
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202008	$	(0.15)
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202009	$	1.21
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202010	$	(0.17)
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202011	$	(0.09)
Electric Island	P36921	Labor Allocation-Union Hrly OT	5507: Allocated Union Overtime labor		202012	$	(0.08)
Electric Island	P36921	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		202006	$	0.03
Electric Island	P36921	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		202009	$	0.25
Electric Island	P36921	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		202010	$	(0.02)
Electric Island	P36921	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		202011	$	(0.03)
Electric Island	P36921	Labor Allocation-Union Premium	5505: Allocated Premium UNION labor		202012	$	(0.02)
Electric Island	P36921	Materials	5302: Materials		202003	$	983.10
Electric Island	P36921	Materials	5302: Materials		202004	$	94.06
Electric Island	P36921	Materials	5302: Materials		202008	$	0.01
Electric Island	P36921	Materials	5302: Materials		202009	$	(92.10)
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202001	$	6.99
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202002	$	42.95
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202003	$	53.14
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202004	$	11.25
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202005	$	(0.25)
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202006	$	2.36

Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202007	$	16.05
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202008	$	0.76
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202009	$	0.62
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202010	$	3,419.17
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202011	$	1.46
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202012	$	(0.27)
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202101	$	11.50
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202102	$	10.35
Electric Island	P36921	Net Periodic Pension Cost	5118: Net Periodic Pension Cost		202103	$	2.01
Electric Island	P36921	Non PGE Labor Straight Time	1502: Non PGE Labor Straight Time		202003	$	741.15
Electric Island	P36921	Non PGE Labor Straight Time	1502: Non PGE Labor Straight Time		202004	$	787.20
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202001	$	10.82
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202002	$	131.61
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202003	$	249.27
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202004	$	(7.75)
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202005	$	(8.80)
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202006	$	3.57
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202007	$	41.00
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202008	$	4.20
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202009	$	(15.42)
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202010	$	2.53
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202011	$	(4.37)
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202012	$	4.35
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202101	$	10.02
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202102	$	18.59
Electric Island	P36921	Non-Labor Allocation	5599: Non-Labor Allocation		202103	$	3.85
Electric Island	P36921	Other Outside Services	2250: Other Outside Services		202003	$	59.58
Electric Island	P36921	Other Outside Services	2250: Other Outside Services		202004	$	1,396.25
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202001	$	0.03
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202002	$	0.18
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202003	$	0.25
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202004	$	0.03
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202005	$	0.01
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202007	$	0.07
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202008	$	0.02
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202009	$	(0.01)
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202010	$	15.18
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202101	$	(0.70)
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202102	$	(0.61)
Electric Island	P36921	OtherPostEmplBeneNonSvcCstLoad	5117: OtherPostEmplBeneNonSvcCstLoad		202103	$	(0.13)
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202001	$	2.01
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202002	$	12.50
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202003	$	15.64
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202004	$	0.64
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202005	$	(0.41)

Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202006	$ 0.93
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202007	$ 0.98
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202008	$ 0.35
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202009	$ 0.27
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202010	$ 0.07
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202011	$ 0.52
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202012	$ (0.04)
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202101	$ 6.46
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202102	$ 5.74
Electric Island	P36921	OtherPostEmplBene-SvcCostLoad	5112: OtherPostEmplBene-SvcCostLoad		202103	$ 1.15
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202001	$ 34.91
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202002	$ 235.58
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202003	$ 336.80
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202004	$ (6.47)
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202005	$ (35.64)
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202006	$ (1.22)
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202007	$ 15.66
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202008	$ (6.09)
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202009	$ (41.77)
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202010	$ 15.96
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202011	$ (15.59)
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202012	$ (4.54)
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202101	$ 123.45
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202102	$ 78.39
Electric Island	P36921	Payroll Taxes	5106: Payroll Taxes		202103	$ 28.71
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202001	$ 20.45
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202002	$ 127.81
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202003	$ 160.77
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202004	$ 6.85
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202005	$ (4.16)
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202006	$ 9.68
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202007	$ 10.44
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202008	$ 3.41
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202009	$ 3.09
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202010	$ 0.62
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202011	$ 5.27
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202012	$ (0.32)
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202101	$ 63.45
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202102	$ 57.07
Electric Island	P36921	Pension Service Costs	5111: Pension Service Costs		202103	$ 11.46
Electric Island	P36921	Prof 4 inch undetermined amoun	2250: Other Outside Services	LOY CLARK PIPELINE CO	202007	$ 3,800.00
Electric Island	P36921	Reclassification	5408: Reclassification		202012	$ (568,689.08)
Electric Island	P36921	Storeroom Materials	2101: Storeroom Materials		202003	$ 352.94
Electric Island	P36921	Storeroom Materials	2101: Storeroom Materials		202004	$ 495.02
Electric Island	P36921	Storeroom Materials	2101: Storeroom Materials		202006	$ 0.02

Electric Island	P36921	Storeroom Materials	2101: Storeroom Materials		202008	$ 0.03
Electric Island	P36921	Storeroom Materials	2101: Storeroom Materials		202009	$ (0.17)
Electric Island	P36921	Storeroom Materials	2101: Storeroom Materials		202010	$ 0.01
Electric Island	P36921	Storeroom Materials	2101: Storeroom Materials		202012	$ 0.02
Electric Island	P36921	Straight Time Labor Hourly	1103: Straight Time Labor Hourly		202002	$ 688.40
Electric Island	P36921	Straight Time Labor Salary	1101: Straight Time Labor Salary		202001	$ 313.87
Electric Island	P36921	Straight Time Labor Salary	1101: Straight Time Labor Salary		202002	$ 934.19
Electric Island	P36921	Straight Time Labor Salary	1101: Straight Time Labor Salary		202003	$ 1,245.41
Electric Island	P36921	Straight Time Labor Salary	1101: Straight Time Labor Salary		202004	$ 191.62
Electric Island	P36921	Straight Time Labor Salary	1101: Straight Time Labor Salary		202101	$ 746.56
Electric Island	P36921	Straight Time Labor Salary	1101: Straight Time Labor Salary		202102	$ 740.54
Electric Island	P36921	Straight Time Labor Salary	1101: Straight Time Labor Salary		202103	$ 246.85
Electric Island	P36921	Straight Time Labor Union	1102: Straight Time Labor Union		202002	$ 228.00
Electric Island	P36921	Straight Time Labor Union	1102: Straight Time Labor Union		202003	$ 1,211.78
Electric Island	P36921	Straight Time Labor Union	1102: Straight Time Labor Union		202006	$ 220.08
Electric Island	P36921	Travel to Daimler Testbed site	2401: Mileage Salary	Riehl,James M	202004	$ 5.75
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202001	$ 51.51
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202002	$ 306.22
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202003	$ 443.10
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202004	$ 12.20
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202005	$ 61.45
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202006	$ (6.09)
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202007	$ 19.63
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202008	$ 0.44
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202009	$ 7.31
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202010	$ 4.90
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202011	$ 78.81
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202012	$ (97.13)
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202101	$ 186.59
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202102	$ 97.98
Electric Island	P36921	Vacation Overhead	5104: Vacation Overhead		202103	$ (9.00)
Electric Island	P36921	April-December 2021 Fcst in Filing	April 2021 - December 2021 Forecast		202104 - 202112	$ 307,069.91

Exhibit 1703 is voluminous in size and provided only in electronic format

Exhibit 1704 is confidential and
provided only in electronic format.
Exhibit is subject to
General Protective Order 21-206

November 11, 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 932
Dated October 29, 2021

Request:

Referencing Attachment A from PGE's response to OPUC DR 901:

a) Please break these expenditures down into the following attributable categories: make ready, EVSE, line extension, and any other relevant category and group these categories by site.
b) Please describe how many EVSE ports the make ready portion of these expenditures will eventually support by site.
c) Please describe the demand capacity of each EVSE port the make ready portion of these expenditures will eventually support grouped by site.
d) Please identify which EVSE ports from these expenditures are in operation now.
e) Please identify which EVSE ports the make ready portion of these expenditures will eventually support will be in operation by the end of calendar year 2022.
f) Please identify when the other EVSE ports the make ready portion of these expenditures will eventually support will be in operation after 2022.

Response:

a. PGE does not track expenses at PGE-owned sites in the same way that we model costs at customer sites in our TE program economic forecasts. For example, PGE does not grant itself a line extension allowance, so line extension costs are not separately calculated at PGE-owned sites. PGE's response to OPUC Data Request No. 901, Attachment A. column "D" provides Accounting Work Orders (AWO) for expenses specific to sites. These expenses include labor, permitting fees, late-stage design changes, materials procurement, and construction. At this point, no expenses are anticipated for EVSE. Construction costs include bringing new EV-dedicated electrical service to the site (1-3 new services per site, depending on volume of fleet vehicles that typically park at each site). This new EV-dedicated service will also feed PGE workplace charging that is currently fed by the building's electrical service.

Please note that AWO: 1000010348 – “EV Preliminary Design & Engineering” contains costs related to strategic and planning work in 2020 to set goals for PGE fleet site upgrades and vehicle conversion commitments. It also includes early design work for the first few sites where EV infrastructure would be constructed.

b. The future number of ports supported by the make-ready work at each site are as follows:

Site	Number of Ports
Avery Regional Service Center	108
Beaverton Service Center	83
Oregon City Service Center	22
Portland Service Center	135
Salem Service Center	96

c. As much as possible, PGE expects to utilize dual-port EVSE with power sharing, such that when all vehicles are plugged in, each vehicle can be charged in a timely way using half of the EVSE’s nameplate power. At 100% fleet electrification, the number of ports at each site, by charger capacity, is forecasted as follows:

	Type of Ports				Total Connected Load (kW)	Total Estimated Demand (with power sharing) (kW)
Site	12 kW	19 kW	60 kW	150 kW		
Avery Regional Service Center	14	27	46	21	3,380	2,424
Beaverton Service Center	27	25	17	14	1,733	1,474
Oregon City Service Center	0	22	0	0	183	128
Portland Service Center	56	30	30	19	3,021	2,126
Salem Service Center	17	27	23	29	3,344	2,417
Total	114	131	116	83	11,661	8,569

d. The construction of this infrastructure is still in progress. As of Q2 2021, PGE had only nine network connected fleet charging ports, which are insufficient to meet current fleet charging needs. To bridge the gap between dedicated fleet charging ports and the number of fleet vehicles requiring support, PGE relies on workplace charging ports to charge fleet passenger vehicles. However, this is a temporary solution as fleet chargers require higher levels of performance, reliability and cyber security.

e. PGE forecasts that 40 EVSE (80 ports) will be in service by the end of 2022, but this remains a forecast and not a plan. To manage costs efficiently, PGE will construct the service infrastructure to support the planned-for number of EVSE, then will install and commission the appropriate EVSE as electric vehicles are adopted into the fleet.

f. The remaining ports related to infrastructure work will come into service as needed to support the conversion of vehicles as they vintage out of service. Our PGE fleet goals are to have 38% of the fleet be electric by 2025, 61% by 2030, and 100% by 2040.

May 11, 2021

TO: Eric Shierman
Public Utility Commission of Oregon

FROM: Robert Macfarlane
Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UE 389
PGE Response to OPUC Data Request No. 033
Dated April 13, 2021

Request:

Please identify the expected net present value of the following list of benefits PGE identified on page 9 of the program application:

a. Early learnings about the grid impacts of heavy-duty charging infrastructure
b. Potential opportunity to test the use of complementary grid edge technologies to mitigate the impact of heavy-duty charging infrastructure
c. Potential opportunity to receive grid services from vehicles or other grid edge technologies such as energy storage system, on-site generation, or grid edge controls
d. Opportunity to enhance planning estimates for heavy-duty fleet vehicle loads
e. Potential opportunity to better understand the value and use cases associated with vehicle-to-grid technologies
f. Development of standards and safety protocols for electrical system workforce training and deployment

Response:

a. Early learnings about the grid impacts of heavy-duty charging infrastructure

PGE recognizes the high level of uncertainty associated with projecting the net present value of the early learnings captured from the projects that may be built under Schedule 53. PGE proposes to use the following scenario analysis to create a range of estimated values by using early learnings to decrease future investments in distribution system infrastructure and energy costs. PGE has also attempted to make conservative assumptions throughout this analysis to acknowledge the uncertain nature of future benefits,

In Table 21 of Section 1.4 of PGE’s 2019 Transportation Electrification Plan, PGE projects that there will be 1,500 heavy-duty electric vehicles in PGE’s service area by 2030. If only 10% of these vehicles were provided 1 MW chargers, PGE may need to support up to 150 MW of new heavy-duty vehicle charging load. If ten 1 MW chargers were grouped together at each charging location, PGE would need to upgrade their distribution network to support 15, 10 MW new load additions throughout their service area.

While the number of charging ports located at a single site and charging port power output may vary, early conversations with customers have informed PGE's assumption that multiple new load additions of this size are likely by 2030. PGE has chosen to focus on a smaller number of large new load additions for this scenario analysis as these have the largest impact on the distribution system.

PGE's Distribution Planning team estimates that current methods of serving new load additions of 10 MW fall under one of six planning scenarios, summarized in the table below. These estimates are made assuming that the maximum nameplate load can be served with the loss of one major system element (N-1 planning).

Scenario	Work required	Likelihood	Cost
1	Line extension only	Low	$0.5M
2	Feeder reconductor only	Low	$1.0M
3	New feeder and new breaker at existing substation	High	$3.0M
4	New feeder and transformer replacement at existing substation	High	$4.0M
5	New feeder and new transformer with substation expansion	Moderate-High	$5.0M
6	New substation and feeder	Moderate	$10.0M

Typical PGE feeders are not loaded beyond 12 MW to ensure N-1 capacity is maintained, meaning that the 15 hypothetical load additions of 10 MW would require more than a utility line extension if an existing feeder was loaded beyond 2 MW, rendering Scenarios 1 and 2 unlikely. PGE proposes to focus on Scenarios 3-5 based on potential likelihood.

To serve these new locations using current methods, PGE could potentially spend $45 to $75M to install new feeders, breakers, transformers and/or upgrade existing substations (Scenarios 3, 4, or 5 only). Alternatively, early learnings could enable PGE to gain insight into the load profiles and diversity factors of heavy-duty vehicle charging loads, providing reasonable assurances that a site with 10 MW of nameplate capacity could be served with less capacity.

PGE is currently conducting internal analyses of light duty vehicle fast charging infrastructure to better quantify demand and energy use. These analyses rely on load profiles and diversity factors derived from PGE and customer owned charging infrastructure and may help PGE update new service design practices. However, these learnings were only available after new loads were connected to PGE's distribution network. PGE believes that Schedule 53 will enable similar learnings to occur before heavy-duty vehicle charging infrastructure is widely deployed. Learnings from Schedule 53 are also expected to impact more than just line extension designs due to the potential size of new load additions.

Lower capacity requirements make it more likely that an existing 12 MW feeder could serve a new charging site. Each instance that the installation of a new feeder is avoided could save up to $2.5M to $4.5M (Scenarios 3 – 5 only).

PGE proposes that early learnings about load profile and diversity factor could enable at least one future 10 MW charging deployment to avoid the installation of a new feeder from an existing substation transformer.

PGE also expects to capture early learnings on power quality and voltage management impacts from heavy-duty vehicle charging locations. Large, highly-variable loads (e.g. an electric arc furnace) have the potential to affect power quality and service reliability to other customers served by a common feeder. One solution that PGE has found to be effective is to require a dedicated feeder and substation transformer for the large customer load, thus mitigating any power quality impacts to nearby customers. Early learnings from heavy-duty vehicle charging may enable PGE to establish new standards for charging profiles, including the ramp rate (rate at which the charging power output increases), power factor, or other attributes. These standards could enable these large new loads to be served by a common feeder and/or common substation transformer with other customers.

PGE proposes that additional learnings about power quality and voltage management issues could avoid the installation of at least one additional new feeder and substation transformer.

To recognize PGE's ability to optimize distribution system designs based on customer-provided information at the time of the new service request and the uncertainty associated with making projections about future new load additions, PGE proposes that only 25% of these potential savings be attributed to this pilot. To provide a range of potential values, PGE has provided attribution rates as low as 15% and as high as 35%. The following tables show the net present value of the early learnings captured in IR33a-f of this information request.

Table 1. Net present value of early learnings - base scenario (25% of CAPEX savings attributed to pilot)

Early Learnings Benefits			
Program	Benefit		NPV $000s
IR 33a	Distribution CAPEX	Avoided new feeder projects (heavy duty charging infrastructure)	1,813
IR 33b	Distribution CAPEX	Avoided feeder reconductoring (complementary grid edge technologies)	878
IR 33d	Distribution CAPEX	Avoided feeder reconductoring	936
IR 33e	Vehicle to Grid	Improved Availability Increases Avoided Cost of Capacity in Future Programs	219
	Demand Response	Improved Availability Increases Avoided Cost of Capacity in Future Programs	116
IR 33f	Distribution CAPEX	Savings from Development of Safety Training Protocals	50
	Benefits		**4,012**

Table 2. Net present value of early learnings - low scenario (15% of CAPEX savings attributed to pilot)

Early Learnings Benefits			
Program	Benefit		NPV $000s
IR 33a	Distribution CAPEX	Avoided new feeder projects (heavy duty charging infrastructure)	1,088
IR 33b	Distribution CAPEX	Avoided feeder reconductoring (complementary grid edge technologies)	527
IR 33d	Distribution CAPEX	Avoided feeder reconductoring	562
IR 33e	Vehicle to Grid	Improved Availability Increases Avoided Cost of Capacity in Future Programs	219
	Demand Response	Improved Availability Increases Avoided Cost of Capacity in Future Programs	116
IR 33f	Distribution CAPEX	Savings from Development of Safety Training Protocals	50
	Benefits		**2,561**

Table 3. Net present value of early learnings - high scenario (35% of CAPEX savings attributed to pilot)

Early Learnings Benefits			
Program	Benefit		NPV $000s
IR 33a	Distribution CAPEX	Avoided new feeder projects (heavy duty charging infrastructure)	2,538
IR 33b	Distribution CAPEX	Avoided feeder reconductoring (complementary grid edge technologies)	1,229
IR 33d	Distribution CAPEX	Avoided feeder reconductoring	1,310
IR 33e	Vehicle to Grid	Improved Availability Increases Avoided Cost of Capacity in Future Programs	219
	Demand Response	Improved Availability Increases Avoided Cost of Capacity in Future Programs	116
IR 33f	Distribution CAPEX	Savings from Development of Safety Training Protocals	50
	Benefits		**5,463**

b. Potential opportunity to test the use of complementary grid edge technologies to mitigate the impact of heavy-duty charging infrastructure

PGE proposes the same scenario analysis described in IR 33.a be used to create a rough estimate of the benefits of complementary grid edge technologies to mitigate the impacts of heavy-duty charging infrastructure.

As discussed above, PGE may need to meet the load of 15 new 10 MW heavy-duty vehicle charging sites complementary grid edge technologies, including energy storage, on-site generation, and advanced controls make it more likely that an existing 12 MW feeder can serve these new loads by buffering peak site demands (energy storage and generation) or providing direct load control to ensure charging sessions stay below a pre-determined peak (advanced controls).

PGE proposes that early learnings about the application of complementary grid edge technologies to mitigate the impact of heavy-duty electric vehicle charging infrastructure could enable up to one future 10 MW charging deployments to avoid the installation of a new feeder using an existing transformer and substation. Low, medium, and high estimations of net present values are shown in IR33.a.

c. Potential opportunity to receive grid services from vehicles or other grid edge technologies such as energy storage system, on-site generation, or grid edge controls

Please reference IR12 for the benefits of grid services from the sites deployed under Schedule 53.

d. Opportunity to enhance planning estimates for heavy-duty fleet vehicle loads

PGE anticipates that the customer interactions and projects that result from Schedule 53 may provide enhanced insight into planned heavy-duty fleet charging infrastructure deployments. The learnings achieved through this pilot, including load profiles, diversity factors, and integrations with complementary grid edge technologies will enable PGE to determine the best locations in its service area to deploy this type of infrastructure. The combined insights and learnings could help PGE provide advice to customers about where to locate infrastructure and include the latest projections in charging infrastructure demand in distribution system upgrade plans.

PGE proposes that enhanced planning estimates would enable PGE to avoid installing a new feeder and breaker using an existing transformer and substation. Low, medium, and high estimations of net present values are shown in IR33.a.

e. Potential opportunity to better understand the value and use cases associated with vehicle-to-grid technologies

PGE propose the following scenario analysis to evaluate the potential benefits of enhanced understanding of vehicles-to-grid and demand response technologies. PGE will again provide a range of estimates and has also attempted to choose conservative assumptions.

PGE proposes that the enhanced understanding of vehicle-to-grid technologies and use cases could result in a 10% improvement in resource availability from vehicle-to-grid programs from 2030 to 2039. To estimate the impact of improved resource availability during this time period, PGE estimates that the vehicle-to-grid battery capacity will be ten times greater than the capacity available in 2022, totaling 1,781 kW (0.4% of PGE total estimated maximum 443 MW of vehicle charging from 1,500 heavy-duty electric vehicles). A 10% improvement in vehicle availability could than result in an incremental 178 kW of capacity. The net present value of the enhanced resource availability is showing the tables presented in IR33a.

PGE also proposes that the enhanced understanding of vehicle-to-grid technologies and use cases could result in a 10% improvement in resource availability from demand response programs from 2030 to 2039. PGE proposes that the demand response capacity could be five times larger than the 2022 level, resulting in a total available the demand reduction capacity of 740 kW. A 10% improvement in the availability of vehicles could result in an incremental increase in 74 kW of demand reduction. The net present value of the enhanced resource availability is shown in the tables presented in IR33a.

f. Development of standards and safety protocols for electrical system workforce training and deployment

Heavy-duty electric vehicle charging infrastructure designs are novel and may benefit from the standards development and workforce training opportunities presented by the projects that could be deployed under Schedule 53. PGE’s early participation in site design, ownership, and operation of make-ready infrastructure present unique opportunities to learn civil and electrical infrastructure design best practices and implement them for future programs. Schedule 53 may also present the local workforce with opportunities to design, engineer, construction, permit, and operate heavy-duty electric vehicle charging infrastructure, resulting in further savings and efficiencies.

If one 10 MW deployment of make-ready charging capacity costs $4M to design, engineer, permit, and construct and PGE standards and a highly trained workforce were to achieve just a 1% cost savings, a $40,000 savings would be achieved by 2030. PGE assumes the 1% of savings is attributable to this pilot. The net present value of this benefit is presented in the tables shown in IR33a.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Capital Budget Process

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Larry Bekkedahl
Archie Ewers

December 2, 2021

Table of Contents

I. Introduction

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

A. My name is Larry Bekkedahl. I am Senior Vice President of Advanced Energy Delivery for PGE. My qualification was previously provided in PGE Exhibit 500.

My name is Archie Ewers. I am a Financial Planning and Analysis Manager. My qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address certain issues raised by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) with respect to PGE's cost controls and capital budgeting and execution process.

Q. What issues did Staff raise regarding cost controls and budgeting?

A. Staff claimed that, as a general matter, PGE's filing demonstrated a lack of focus on cost control.[1] Staff raised concerns regarding PGE's budgeting process and the challenges of understanding the components, including project justification forms (PJF) and change orders.[2] Staff invited PGE to clarify its cost control process and protocols in reply testimony.[3]

Q. Please summarize your testimony.

A. PGE has a rigorous top-to-bottom and bottom-to-top cost management and capital budget process. The process involves careful review at defined stages in the project development and construction process and at multiple levels within the Company. In this way, PGE ensures that every project benefits customers and is undertaken in an economical and prudent manner. As an example, PGE's effective cost management is demonstrated by the fact that the

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[1] Staff/100, Muldoon/5-8.
[2] Staff/700, Hanhan/5, 8-14.
[3] Staff/700, Hanhan/14.

Integrated Operations Center (IOC) came in under budget. Staff's concerns regarding the PJFs provided by PGE reflect a misunderstanding of the documents, which were consistent with—and in some cases more detailed than—information provided in PGE's past rate cases (which had been sufficient for Staff).

Q. How is your testimony organized?

A. Our testimony contains the following sections:

- Section II – PGE's Capital Cost Management Practices
- Section III – Cost Controls at the Project Level
- Section IV – Projection Justification Forms
- Section V – Change Orders
- Section VI – Summary
- Section VII - Qualifications

II. PGE'S Capital Cost Management Practices

Q. Please summarize Staff's comments on PGE's capital cost management practices.

A. Staff asserted that they were "unable to detect a focus on cost control for PGE's capital investments in transmission and distribution facilities" and recommended excluding a portion of PGE's capital investment for "apparent mismanagement of costs."[4] Staff alleged that "PGE's annual budgeting process appears to eliminate controls that ensure" prudent cost management of new capital investments.[5] Finally, Staff observed that the PJFs are "insufficient, unintuitive, and are not conducive to regulatory oversight for prudence review."[6]

Q. Please provide a high-level overview of PGE's capital cost management practices.

A. PGE employs a simultaneous bottom-up and top-down approach to cost management, with multiple layers of controls. PGE's annual capital budgeting process is governed primarily by three groups: PGE's Board of Directors (BOD), the Capital Review Group (CRG), and Business Sponsor Groups (BSG). This is a layered process which is explained in more detail below, but here is a brief summary. From the "bottom-up," based on rigorous review of projects' need, scope, budget, and forecast, the BSG approves a portfolio of projects for funding. This is shared with the CRG which adjusts funding priorities across PGE. The aggregate annual budget is presented to the BOD for review and approval. The rigorous review is continuous, and the BOD budget review is performed once annually with incremental changes and revisions submitted and reviewed as needed. From the "top-down," the BOD is the ultimate decision-maker for determining the amount of capital available across PGE. The CRG then allocates this to BSGs based on funding allocation priorities, and then

[4] Staff/100, Muldoon/7.
[5] Staff/700, Hanhan/13.
[6] Staff/700, Hanhan/13.

each BSG manages its allocation by reprioritizing and balancing its portfolio of projects.

Q. Please briefly describe the role and responsibilities of the BOD, CRG, and BSGs in establishing PGE's annual capital budget.

A. The BOD is responsible for reviewing and approving the annual capital budget. In addition, the BOD approves large strategic projects and future-year obligations for long-lead-time equipment purchases. To the extent additional capital funds are needed after the annual budget is approved, the BOD must approve any additional spending. Finally, the BOD also determines the CEO's extended approval authority, which provides the CEO with limited authority to approve budgets over the BOD-approved amount.

The annual capital budget is recommended to the BOD by the CRG. The CRG develops the proposed annual budget based on the rigorous portfolio development and management of each BSG, and evaluates the use of funds throughout the year on a monthly basis. Each BSG develops a proposed annual budget based on its three- to five-year project road map that prioritizes projects based on PGE's strategic initiatives to benefit customers and project readiness.

Q. Once the annual budget is approved, how are funds managed within the year?

A. Portfolio Managers and Project Managers oversee the daily control of portfolios and projects. Monthly reports and monthly funding requests are provided to the BSG for review and consideration. The CRG reviews the funding requests, the overall impact to PGE's portfolio and strategic goals, and is responsible for approving the annual budgets allocated to each BSG.

To the extent funds in excess of the annual approved amount are requested, the following tools are available: seek reallocation of funds between BSGs; reject funds requested; require budget cuts across other projects; access reserves funding[7] within the BSG; access funds called "non-budgeted CEO matters" which is an amount of reserve funding that can be used in emergency situations or as temporary allocations; or go to the BOD for additional funds.

Q. How does PGE manage capital costs over multiple years to balance customer price impacts against the necessity of maintaining a reliable and safe system?

A. PGE incorporates a multi-year outlook in our capital planning and management in several ways. The BSG develops three- and five-year roadmaps which estimate projects over a longer-term duration. This provides the BSG with a broader view of the portfolio and enables the portfolio manager to balance project priority and cost management. The roadmaps enable portfolio managers to maintain funding stability over time and allow PGE executives to monitor the overall trend of the capital programs. PGE also employs analytical tools like asset risk models, system planning models, customer forecasts, and community development plans to help drive long term plans. With this multi-year perspective, PGE leaders can carefully balance customer price impacts with the need to invest in a reliable and safe system.

Q. Given the pivotal role of the BSG in PGE's cost control practices, please provide more information about its structure.

A. There are six BSGs under the CRG: Transmission and Distribution (T&D), Generation, Information Technology, Customer Services, Grid Architecture, and Buildings & Vehicles Services. Ninety-four percent of the capital budget is driven by the T&D and Generation BSGs. Each BSG is responsible for approving the right projects to support PGE's ability to

[7] "Reserves" is a funding source that PGE uses to fund stage-gated, emerging, and unanticipated projects that are not fully scoped or known when capital budgets are approved. This includes funding set aside for stage-gated projects, new large customer load requests, unanticipated increases on in-flight projects, or other emerging opportunities during the course of the year. Conversely, when an in-flight project gains efficiency and has dollars to give back, the funding give back will go into the reserves to be allocated elsewhere.

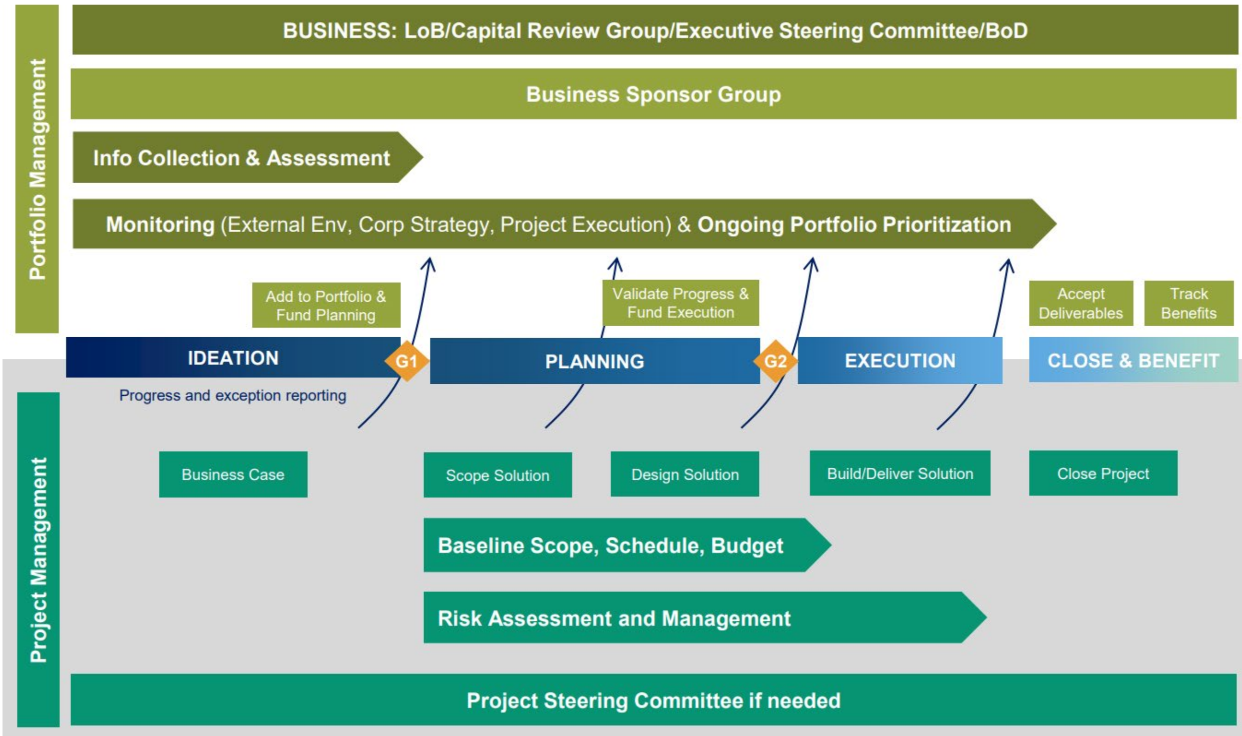
deliver on its strategy for the benefit of its customers. The BSG performs portfolio planning by developing three- to five-year road maps that translate the corporate strategy into specific initiatives and prioritizes project execution and funding. The BSG performs portfolio management by approving projects at stage-gate milestones, allocating funds to projects based on performance, monitoring portfolio execution, and escalating issues to the CRG as needed.

The BSG is comprised of senior leaders within the organization who serve as voting members and cross-functional leaders who serve as non-voting members. The BSG meets monthly to review projects and consider funding requests.

Q. Please provide a visual representation of the project management and cost control measures at the portfolio level.

A. See Figure 1.

Figure 1
Cost Control and Project Management at Portfolio Level



Q. Figure 1 shows two primary workstreams: Portfolio Management and Project Management. Please summarize each of these.

A. Portfolio Management refers to the management of the entire portfolio within a particular area, such as T&D. The two primary leadership roles in Portfolio Management are performed by the BSG leadership and a Portfolio Manager. Portfolio Management decides when projects are ready to move from the roadmap to active work, allocates funds to projects based on performance, approves projects at stage-gate milestones, monitors portfolio execution and delivery of benefits, manages portfolio exceptions, and escalates issues to the CRG as needed. The Portfolio Manager ensures projects benefit customers by aligning with and delivering on PGE’s strategy, allocates budgeted dollars to projects based on performance, approve stage-gate milestones for projects, monitors portfolio execution and benefits delivery, manages project expectation, ensures value in the portfolio, actively balances the portfolio, and identifies and escalates issues, as needed.

Project Management refers to the management of an individual project through the stage-gating process by a Project Managers. The Project Manager manages a project's progression through the planning and execution stage-gates and helps keep the project on schedule and within the budget, as discussed in more depth below.

Q. What is the stage-gating process?

A. The stage-gating process is a project management technique that PGE uses to assess project readiness using multiple project stages. Stage-gating helps Project Managers think through common project scoping and execution considerations, and minimize disruptions or scope changes by leveraging thoughtful planning.

There are four stages used by PGE: ideation, planning, execution, and close and benefit. These are shown in the blue rectangles in Figure 1. The work performed by Portfolio Management and Project Management flows through these four stage-gates.

A Project Manager manages each project through the stage-gating process. The first stage is "ideation," where the business case is developed. Upon approval by the Portfolio Manager and BSG leadership, the project moves into the "planning" stage and requests planning dollars. This is shown as the orange diamond labeled "G1" in Figure 1. Planning dollars are generally in the several-hundred-thousand-dollar range and are used to:

- Re-validate the business case, conducting studies and analyses as needed;
- Conduct engineering design;
- Secure permits and property easements;
- Confirm tasks, resources, budget, and schedule; and

- Finalize vendor bids and agreements.

Funding for long-lead-time equipment is also requested during the planning phase. This allows PGE to maintain project timelines because it can take over a year for certain equipment to be delivered. To be clear, procurement of long-lead-time items is not an irrevocable commitment to a project because such items can be repurposed, used as a spare, or sold.

Upon completion of the planning stage, the project is again reviewed by the Portfolio Manager and BSG. If approved, the project then moves into the "execution" stage and requests execution dollars. This is shown as the orange diamond labeled "G2" in Figure 1. By the time execution funds are requested at the conclusion of the planning stage, the Project Manager has performed the due diligence necessary to develop a total project cost estimate, which is presented when requesting execution funds.

While in the execution phase, on a monthly basis, the Project Manager reviews actual spend compared to budget; updates forecast of spend timing; reports and takes action on significant variances; and updates in-service dates. All of this is then reviewed by the Portfolio Manager and shared with the BSG. This is a critical cost control practice employed by PGE.

The fourth and final stage is close and benefit, which occurs when the project goes in-service and all accounting and documentation for the project is completed.

Q. Above you stated that each project undergoes a monthly evaluation where, among other things, actual spend is compared to budget. What happens if there is a variance?

A. Each month, projects in the execution phase with a variance of more than 10 percent between actuals and budget or between forecast and budget are flagged for further scrutiny and analysis by the Portfolio Manager. Results are presented to the BSG. Projects with a variance of more than 10 percent while in the execution phase may be required to limit or reduce funding, or the Project Manager may need to make a case for additional funding. This is another example of the multiple layers of cost control and management employed at PGE. In some cases, funding for projects will be paused if there are concerns with cost management, scope, or timeline.

Q. How does PGE estimate costs in order to request planning and execution funds?

A. The Generation, Transmission and Distribution Project Management Office (GTD PMO) is responsible for estimating costs for capital projects. The estimates are used as the baseline budget requests for the planning and execution gates, with updates to the forecast and budget occurring as actual contract commitments are made. Cost estimates are developed with an in-depth understanding of construction processes and methods. They are data driven with market, actual, and historical information maintained within one estimating database.

PGE employs standardized estimation parameters, shown in Table 1. Planning funds are requested based on a "feasibility estimate," which has a range of accuracy of -30% to +50%, based on Association for the Advancement of Cost Engineering (AACE International) guidelines (see, Stage 3 in Table 1).

Estimate accuracy increases as design progresses. Execution funds are requested based on the "Issued for Construction (IFC) Design Estimate," which has a range of accuracy of -15% to +20% (see Stage 5 in Table 1).

Table 1
Standardized Estimation Parameters

Project Management Playbook Stages	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5	Stage 6	Stage 7
Playbook Stage Name	Project Planning	Portfolio Planning	Execution Planning	Engineering/ Permitting	Construction Planning	Construction	Project Closeout
Estimate Type and Accuracy	**Conceptual Screening** *-50% to +100%*		**Feasibility Estimate** *-30% to +50%*[1]	**30% Design Estimate** *-20% to +30%*	**IFC Design Estimate** *-15% to +20%*		
Intended Use	Portfolio screening of projects and evaluating options		Request Planning Funds	Update planning fund request (if needed)	Request Execution funds		

Q. You have described the rigor with which PGE plans projects, estimates costs, and employs a stage-gating process to require BSG review and approval prior to receiving funds. Does PGE use other cost control management practices?

A. Yes. PGE has an annual process that must be followed before any money can be spent, called authorization to spend (ATS). This begins with PGE's annual budgeting process in May, when each project submits its annual spending plan for the following year for consideration by the BSG and, ultimately, the CRG. This is called "Capital Call." Between May and November, the Portfolio Manager analyzes the proposed spending requests and modifies the portfolio's three- to five-year roadmap. Based on this analysis, the Portfolio Manager recommends to the BSG approval of funding for projects. Once each BSG has approved its annual spending plan, these are brought to the CRG for review and approval.

Once the CRG approves the spending plan, there is one more step before funds are available to be spent. This is the ATS process, which occurs in November. ATS is the confirmation of budgets submitted in May. Depending on the size of the project's budget, there are multiple layers of approval that are required before funds are authorized to be spent. This is yet another component to PGE's cost control management. In order to have funds released and allowed to be spent based on approved project funds, all projects require the approval of Corporate Planning, Asset Accounting, Environmental Services, the sponsoring department's manager, and the Project Process Administrator.

Additional approvals are required as a project increases in cost. If a project is more than $350,000, it needs the additional approval of the sponsoring department's senior manager. If the project is more than $500,000, it needs the approval of the sponsoring department's director. If the project is more than $1 million, it needs the approval of the organization's vice president and lastly, if the project is more than $5 million, it needs the approval of the Chief Financial Officer. These approvals are sequential and cumulative. For example, if a project is more than $5 million, it will need approval from each layer of management prior to seeking approval from the next higher level of management. If any person in the authority chain rejects a project, the project does not progress up the chain and is sent back to the Project Manager for revision.

Q. Part of cost control management is prioritizing how limited funds are spent. Given Staff's scrutiny of PGE's T&D capital spending, please explain how PGE prioritizes which T&D projects to fund.

A. Projects are identified as belonging to one of four categories: maintaining the business, compliance, customer-driven, and new opportunities. "Maintaining the business" includes necessary work such as rebuilding or replacing defunct equipment for reliability and safety reasons. "Compliance" projects include necessary work to be compliant with the rules and regulations that govern the electric utility, including Facilities Inspection and Treatment to the

National Electrical Safety Code (FITNES) and North American Electric Reliability Corporation (NERC), among other regulatory bodies. "Customer-driven" projects include distribution line construction, substation upgrades, etc. "New opportunities" include pursuits such as energy storage projects.

Projects are prioritized based on business and customer benefit with specific focus on maintaining the business and compliance. Over ninety percent of PGE's annual capital budget is related to must-do projects to maintain the business, comply with regulations, and serve the needs of customers. As an example, only four percent of PGE's 2021 annual T&D portfolio was designated for new opportunities.

Q. Please summarize PGE's cost control management practices.

A. The annual capital budgeting process is governed primarily by three groups: PGE's BOD, the CRG, and the BSGs. PGE employs a simultaneous bottom-up and top-down approach to cost control management, with multiple layers of controls in between. On one end, individual Project Managers create annual capital project plans that are provided to their BSG. There is a Portfolio Manager within each BSG who aggregates the project recommendations and triages them against the BSG's three- to five-year roadmap, forecasted customer demand, and strategic asset management to determine the best portfolio of projects to present to the BSG and CRG. The CRG then reviews the portfolios from each BSG.

On the other end of this process, PGE's BOD reviews and approves the total capital budget based on the aggregated annual plans from the BSGs that were reviewed by the CRG. This approved annual budget is then passed back to the CRG, and the CRG allocates the final dollars to the BSGs, based on the board approved plan for the year.

As a project progresses, variances are assessed each month, and any actual or forecasted variance of more than 10 percent is carefully scrutinized to ensure that the project remains prudent and that project costs are controlled to the maximum extent possible.

III. Cost Controls at the Project Level

Q. Based on the previous section, stage-gating is a critical component to how PGE manages costs. Please provide more information on why PGE uses stage-gating.

A. Stage-gating reduces the risk of over-allocating funds to projects that do not yet have a fully developed scope and budget. This optimizes PGE's ability to execute on its capital plan during the year and serves as a cost control measure checkpoint to ensure projects have the necessary resources and plans before funding is committed by the BSG/CRG.

Q. Do all projects go through stage-gating?

A. No. Gated projects include most "base" and "strategic" projects, but do not include "blanket" projects. "Base projects" are a general portfolio that includes projects that sustain and grow the business, and include both gated and non-gated blanket projects. "Blanket projects" cover ongoing work and include numerous individual work orders, meaning gating is not necessary or feasible. Examples of blanket projects include customer line extensions; joint use capital, such as pole attachments; other customer work, such as meter installations; and municipality work, such as road widenings. More information on blanket projects is provided in Exhibit 2000. "Strategic projects" are larger, more complex projects that have a high profile. Examples of strategic projects are new power generating facilities and the Integrated Operations Center.

Q. Does your description of the capital budgeting process using annual and stage-gating methods in combination match the description of the PGE capital budgeting process as provided by Staff?[8]

A. Some portions match, however, the underlying controls created through the use of stage-

[8] Staff/700, Hanhan/10-11.

gating were missed by Staff. Staff's understanding is limited to the annual process and does not capture the controls that guide individual projects on a monthly basis *and* over multiple years because of stage-gating.

Q. Did PGE explain to Staff that its current capital management process has been updated since its last rate case?

A. Yes. PGE met with Staff on multiple occasions to discuss the PJFs, changes orders, and PGE's capital budgeting and execution process. For example, during the October 8, 2021 meeting, PGE provided Staff with a presentation on PGE's budget setting and approval process, the role and function of the BOD, CRG, and BSGs, how PGE prioritizes spending in the T&D capital portfolio, and PGE's stage-gating process, including discussion of planning funds and execution funds and allowed variances between forecast and budget.[9] PGE highlighted that its process had changed since its last general rate case. PGE began to use stage-gating in 2019, just after PGE's last general rate case, Docket UE 335. PGE explained to Staff that stage-gating brings with it more controls, more review, and more scrutiny to projects and budgets than PGE's prior process.

Q. Why did PGE change its process?

A. PGE sought to enhance its project portfolio management practices to improve project selection, resource utilization, and accountability to benefits and outcomes. PGE found improvements to the overall project portfolio management by researching and adopting the Gartner Project Portfolio Management Model.[10]

Q. Do projects experience fewer or greater controls now compared to PGE's prior process?

A. There are more controls now than in the past. Under the new process, the project is required

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[9] *See*, Confidential Exhibit 1801.
[10] *See*, ITScore Overview for Program and Portfolio Management (gartner.com)

to complete milestones to show readiness at each stage before it can obtain funding. That improves the probability of successfully delivering on project benefits while remaining within the total approved project budget.

Q. Staff stated in testimony that "PGE does not set budget targets for projects."[11] Is this accurate?

A. No, that is not accurate. When a project is in the planning stage-gate, planning funds are requested to conduct engineering design; secure permits and property easements; confirm tasks, resources, budget and schedule; finalize vendor bids and agreements; and order long lead time items. At this stage, the total estimated project costs including estimated execution costs will be included in the BSG multi-year capital road map for visibility. When a project moves to the execution stage, it requests execution dollars. The Portfolio Manager will compare and evaluate the execution request to the amount from the planning phase shown on the BSG capital road map. Differences will require additional analysis and presentation to the BSG.

If the project is approved to move to the execution phase, the relevant revision on the PJF will say "Request for Execution Funding."[12] The "Total Project Budget" that is shown at this time is the best proxy for the initial budget of a project. When the "Total Project Budget" is estimated and requested at during the "Request for Execution Funding," this is at this point in time when sufficient planning and analysis has occurred to make an informed multi-year project cost estimate. Execution funds are requested based on the standardized estimation parameter of IFC design estimate, which has an accuracy range of -15% to +20%.[13] We refer

[11] Staff/700, Hanhan/10.
[12] In most cases, projects that began prior to the implementation of stage-gating in 2019 may not be as clear.
[13] *See*, Stage 5 of Table 1.

to this as the "estimated total project budget" in PGE Exhibit 2000.

Q. Staff also stated that "[u]ltimately, the budget for a project appears to be what the project ends up costing, rather than a targeted amount."[14] Is this a fair description of PGE's process?

A. No. This is a misconception based on not fully understanding the stage-gating and review process. As an initial matter, PGE intentionally does not request the entire project cost at the very beginning of the project. As discussed previously, there is a standardized process to estimate costs with increasing accuracy as more information is obtained. In particular, planning funds are requested prior to execution funds specifically to obtain more information to better estimate the total cost of the project. It is not until execution funds are requested that there is an informed total cost estimate. This estimate is based on the IFC design estimate and has an accuracy range of -15% to +20%. This means it is acceptable for the final project cost to be within -15% to +20% of the project cost estimate made when execution funds are requested. This range represents the complexities associated with large, multi-year projects.

PGE's rigorous review of the project does *not* end when execution funds are requested. Every month the Project Manager updates the project's forecast compared to actual spend; any variances over 10 percent are noted and appropriate actions are taken. Requests for funding increases or decreases are considered by the BSG and approved or rejected. The Portfolio Manager and BSG may reject the requested funds because the project is overspending compared to budget and needs to reevaluate and get back on track.

Staff's confusion may stem from the fact that rejections of requested funds may not appear on the PJF where project funding changes are requested and documented. If a funding

[14] Staff/700, Hanhan/8.

request is rejected, it will not show up in the Revision Summary table on the PJF, but there may be a narrative request for funding in one of the text boxes of the PJF. This indicates the funds were requested but rejected. Because Staff could not see on the PJFs the rejections of requested funds, Staff seemed to assume that every request for additional funding is arbitrarily approved with no review or oversight. The Revision Summary in the PJF only shows approved revisions to a project because the rejection history does not contribute meaningful information to the future spending of the project.

Q. In testimony, Staff states that [Begin Confidential] [redacted].[15] [End Confidential] Is that an accurate understanding of PGE's process?

A. No. First, the Portfolio Manager alone does not have the authority to postpone projects to a different year. The approval is made at the BSG and CRG level. More importantly, postponement of any project or portion of a project is not used as a mechanism to allow projects to spend imprudently. A project that incurs significant overruns compared to budget (meaning a variance over 10 percent when in the execution stage or a variance over 50 percent when in the planning stage) would be flagged by the Portfolio Manager and a presentation to the BSG may be required for approval to move forward with the project. It is the Portfolio Manager's role to ensure the portfolio delivers value and when a project's costs significantly overrun, it puts delivery of the portfolio value in jeopardy.

Q. Why might a project have funding moved from one year to another?

[15] Staff/700, Hanhan/12.

A. A project might have funding moved from one year because of schedule changes due to lack of availability of materials or labor, delays in permitting, customer scheduling delays, or because a higher priority project needed to take its place.

Q. If a project's funding is moved from one year to another, does this mean that the project gets additional funding?

A. No. Moving a project from one year to the next does not change its total approved funding. It only changes its schedule, and therefore the year the approved funding will be executed. While these shifts can help maintain the overall portfolio budget in the current year, if funds are moved into a future year, that will result in a trade off in that future year.

Q. How does PGE ensure that individual projects are not being mismanaged?

A. Projects are reviewed monthly by Portfolio Managers for changes in spending. It is through this review process that issues surface and are proactively addressed. Portfolio Managers will work with project teams to evaluate the issue, validate it, resolve it if possible, and potentially look for trade-offs in the portfolio to balance any unavoidable changes.

Q. In his opening testimony Mr. Muldoon states that "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."[16] Did PGE explain its cost control methods to Staff members Ms. Hanhan and Mr. Sayen?

A. Yes. As mentioned above, PGE met with Staff, including Ms. Hanhan and Mr. Sayen, on multiple occasions to explain the details of our process.

Q. Staff specifically mentions the IOC as an example of apparent mismanagement of costs and proposed a [Begin Confidential] [redacted] [End Confidential] adjustment to

[16] Staff/100, Muldoon/7.

capital for the IOC.[17] **What was the basis for Staff's adjustment?**

A. Staff's proposed adjustment was based on Staff's understanding that the approved capital budget for the IOC was **[Begin Confidential]** [redacted] **[End Confidential]**. Staff's **[Begin Confidential]** [redacted] **[End Confidential]** adjustment is half of the difference between the **[Begin Confidential]** [redacted] **[End Confidential]** cost included in PGE's initial filing and the number Staff "was able to identify as the initial total cost projection," **[Begin Confidential]** [redacted].[18] **[End Confidential]**

Q. What was Staff's basis for using [Begin Confidential] [redacted] **[End Confidential] as the "initial total cost projection"?**

A. Staff used **[Begin Confidential]** [redacted] **[End Confidential]** as the "initial total cost" projection based on its **[Begin Confidential]** "[redacted]" **[End Confidential]**; Staff cited PGE's response to OPUC Data Request No. 880 as the reference.[19]

Q. What was OPUC Data Request No. 880 and how did PGE's respond?

A. OPUC Data Request No. 880 referenced an internal presentation made in March 2019, which we provided in response to OPUC Data Request No. 499 that asked for the presentations about the IOC that were made to PGE's Operations Steering Committee. The data request referenced slide 8 of that presentation that show a cost of **[Begin Confidential]** [redacted] **[End Confidential]**. Staff asked if this was the Guaranteed Maximum Price (GMP), whether the IOC was constructed within that GMP, and whether the GMP changed throughout the

[17] Staff/100, Muldoon/7; Staff/700, Hanhan/15-17.
[18] Staff/700, Hanhan/17.
[19] Staff/700, Hanhan/15.

project.

In our response, we clearly stated that "Slide 8 shows an *estimate* of total project costs as of March 2019. The Guaranteed Maximum Price (GMP) was finalized on August 22, 2019 at **[Begin Confidential]** [redacted] **[End Confidential]**. The GMP applies to direct construction costs only."[20]

Q. Did Staff submit any further discovery to determine the estimated total project budget for the IOC?

A. No.

Q. Staff asserted that "Staff asked for original budgets and cost tracking [but] did not receive this data in time to include in this testimony."[21] How do you respond?

A. It is unclear what Staff is referring to. The last data request regarding the IOC was OPUC Data Request No. 888 to which we responded on October 7, 2021, two and a half weeks prior to Staff filing Opening Testimony. If Staff is referring to OPUC Data Request No. 889, to which we responded on October 13, 2021, the IOC was *not* included in the list of projects for which Staff requested information.

Q. What was the original budget of this strategic project as approved by PGE's BOD?

A. The total project cost approved by PGE's BOD in the annual capital plan was **[Begin Confidential]** [redacted] **[End Confidential]**. This can be confirmed with the associated board presentation and resolution for the capital plan.

Q. Why did Staff not receive this information?

A. This information was not requested. Most of Staff's data requests specifically referenced

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[20] *See* Staff/703, PGE's response to OPUC Data Request No. 880, provided in Exhibit 1802. Emphasis in the original.
[21] Staff/700, Hanhan/16.

statements made in PGE Exhibit 800 or in PGE's internal presentations to the Operations Steering Committee, which were provided upon request in response to OPUC Data Request No. 499.

Q. Why was a specific project budget approved by PGE's BOD for the IOC and not for other capital projects?

A. This project was deemed to be a large strategic project based on the size, complexity, and strategic need. As mentioned above, all strategic projects are reviewed and approved by PGE's BOD under a capital resolution specific to the project. This offers greater oversight by the PGE BOD as compared to other projects. Other examples include Carty, Wheatridge, and Port Westward II.

Q. Is the IOC now complete?

A. Yes. The IOC was completed at the end of October 2021, and PGE employees began moving into the building at the beginning of November 2021.

Q. Was the final cost of the IOC consistent with its total approved capital budget of $215.7 million?

A. No, in fact PGE completed the IOC <u>under</u> the approved capital budget.

Q. Have Staff's concerns regarding the IOC been resolved?

A. Yes. The IOC is a part of the second stipulation reached in the general rate case.

Q. Does the IOC cost support the claims made by Staff that PGE is mismanaging its costs?

A. No. Actually, the IOC coming in under budget demonstrates that PGE effectively manages costs to the benefit of customers.

Q. Does PGE have any other evidence to support its careful cost management of capital projects?

A. Yes. In Exhibit 2000, PGE details the prudency and cost control measures regarding the projects identified by Staff in their Opening Testimony.

IV. Project Justification Forms (PJFS)

Q. Staff states "PJFs are insufficient, unintuitive, and are not conducive to regulatory oversight for prudence review."[22] Please respond.

A. Below, we discuss the challenges Staff appear to have experienced and refute their claims that PJFs are not useful for understanding the prudency of a capital project.

Q. Please summarize what a PJF is and what it provides.

A. The PJF is a form populated by Project Managers and maintained within PGE's project management software, PowerPlan. For each project, the PJF contains the business justification, scope, budget, schedule, project alternatives considered, and possible project risks. This is also where any revisions to the project are input for approval or rejection by the chain of approvers.

The PJF contains a running list of all requested and approved changes to capital funds and a brief summary of why the change was requested. To be clear, when the revision shows an increase or decrease to an annual budget or the total project budget, this is the *net sum* of all changes requested during that revision. In some cases, there may be increases and decreases to certain items, but only the net change is shown in the revision summary. Typically, the justification text boxes will briefly describe the cause for both increases and decreases but may not describe every change if they are relatively small.

The "Revision Summary" shows the approved budget changes, referred to by a revision number. Finally, the PJF summarizes the need for the project and the risks of not completing the project. Some projects, such as reliability-driven projects, will also have a whitepaper providing a more extensive justification of the project need and risks of not completing the

[22] Staff/700, Hanhan/13.

project.

Q. Has Staff previously reviewed PJFs?

A. Yes. PJFs have been provided to Staff in at least the last three GRCs.

Q. Have the PJFs changed since PGE's last general rate case?

A. Yes. The forms have changed to reflect the stage-gating process described in Section II. To be clear, the new stage-gating process began in 2019. The new PJF format did not go-live in PowerPlan until the end of 2020.

Q. What alterations were made as a result of this update?

A. There are now three different forms depending on the type of project: gated, ungated, or elevated. This way, each form has fields (text boxes) requiring information specific to that type of project. Previously, the old PJF had one open-ended text box for Project Managers to include all pertinent information. To ensure consistent provision of information, the new PJF have individual fields to prompt the Project Manager to include each piece of information.

An example of the old PJF is shown in Exhibit 1803. Take for example, the first text box on page one. This single field contains five pieces of information: the revision number; the approval date; the approval meeting (e.g., BSG); whether the requested funding is for planning or execution dollars; and a description of the change in funds. All this information is still provided in the new PJF (see example in Exhibit 1804) but in five separate fields. This adds rigor to ensure the Project Manager is providing all information, but requires the reader to read all fields together the glean the same information that had previously been provided in a single field.

Q. Does the new PJF include more or less information than the old PJF?

A. The new PJF includes more information across more fields. As stated above, while the information for a project could largely be viewed in one field in the old form, the old form did not require a Project Manager to enter all the needed information. The new form breaks down the information into individual fields and has additional fields to address stage-gating.

Q. Given that the new forms have more, not less, information than the old, how does PGE respond to Staff's claim that the information contained in the forms is insufficient?

A. Staff has received and reviewed PJFs in at least the last three rate cases going back six years without similar complaints. It is perplexing that Staff finds the new, more detailed forms insufficient when it did not previously raise concerns regarding the older, less detailed forms.

The change in PJF format may have created challenges for Staff when reviewing projects that had been started under the old system and completed under the new system. However, these circumstances do not justify Staff's wholesale characterization of the forms as incomplete, irrelevant, or not useful for a prudency review.

Q. Please explain how a project started under the old system but completed under the new system would appear to a reviewer.

A. This would be the most challenging type of project to review. Project Managers were tasked with inputting the information from an already started project into the new forms at the point that the system changed. However, the old form also remains appended to these projects so that the project information from prior to the start of the new system was not lost.

When printed for review, typically, the new form is shown first, with the old form shown second. Both the old and new forms start with the Revision Summary table, which makes it easy to identify where each form begin.

The best way for a reviewer to understand a project that had started under the old system and completed under the new system would be to find the old form and review it first and then review the new form which picks up from where the old form had left off. This requires the reviewer to understand both the old and new processes. Without that understanding, the forms could appear unintuitive and could be challenging to review. PGE walked through how to read the new and old PJFs when we met with Staff.

Q. Going forward, will this continue to be an issue for a reviewer of capital projects?

A. No. Going forward, only the new PJFs will exists, which will reduce the confusion associated with the PJF.

Q. Does PGE believe it is necessary to make any further changes to the PJFs because of Staff's criticism of the forms?

A. No. As stated above, we believe the information included in these forms is appropriate, complete, and relevant when reviewing the prudence of capital projects. In addition, we do not believe that the challenges Staff may have experienced because of the changes in our process justify Staff's wholesale condemnation of the substance of the information contained in the PJFs, which has been provided to Staff and reviewed in multiple other rate cases.

V. Change Orders

Q. In testimony Staff states that they were "very surprised" by PGE's objection to Staff's data request for change orders because "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 cost overruns."[23] Does this description match PGE's understanding of prior rate case data requests for change orders?

A. No. PGE reviewed the data requests received from the last three rate cases and did not find Staff's statements to align with the information found as we describe below. In prior rate cases, Staff has not sought information on change orders at the level of detail sought here. Thus, PGE has not previously had occasion to explain its company-specific change order process to Staff.

Q. What is a change order?

A. Change orders are the documentation between PGE and a vendor/contractor for changes to a project and are a part of an agreement with the vendor/contractor for the project. A change order can cover nearly every aspect of a project, ranging from changing the location of a handrail to the quantity of gravel purchased, so long as the agreement between PGE and the vendor and/or contractor requires a change order to be submitted. Agreements with vendors and contractors typically include the requirement that nearly every change, large or small, be submitted and approved through a change order. This maintains a record between PGE and the vendor and/or contractor and ensures both parties are in agreement on all aspects of the project.

[23] Staff/700, Hanhan/9.

Colloquially, PGE may also use the term “change orders” for large changes to a project that are included as revisions on PGE’s PJF.

Q. Why are change orders between PGE and vendors/contractors not the best source of information for a capital project?

A. First, change orders are in place *only* with outside vendors/contractors. Use of internal PGE labor, for example, is not documented via a change order. Thus, any change to internal labor costs would not be captured in a change order. As a result, change orders provide an incomplete picture of PGE’s spending and budget management. In contrast, the PJF documents changes to both internal and external costs, making the PJF the most comprehensive source to document PGE’s spending and budget management.

Q. Did Staff request change orders in UE 335, PGE’s most recent general rate case?

A. Yes, on March 15, 2018, in OPUC Data Request No. 131, Staff requested change orders for every project completed after July 2017.[24]

Q. How did PGE respond?

A. PGE referred Staff to PGE’s response to OPUC Data Request No. 129, which provided only PJFs.[25]

Q. Were any detailed change orders between PGE and a vendor/contractor provided in this data response?

A. No. Only the PJFs were provided.

Q. After receiving this answer, did Staff request additional information regarding change orders between PGE and vendors/contractors or suggest in its testimony that the information provided was not sufficient?

[24] *See*, Exhibit 1805.
[25] *See*, Exhibit 1805.

A. No.

Q. Did Staff request change orders in UE 319, the general rate case that preceded UE 335?

A. Yes. In UE 319, Staff requested all of the change orders for just the Carty Generating Station in OPUC Data Request No. 148.[26]

Q. How did PGE respond?

A. PGE's response to the data request shows that Staff withdrew the request. Unfortunately, we do not have any information on file to show the context of this withdrawal.

Q. Did Staff request change orders in the rate case before that, UE 294?

A. Yes. In OPUC Data Request No. 171, Staff requested change orders for just the Carty Generating Station, and PGE provided eleven change orders between PGE and Abeinsa (the EPC contractor) for the project in response.[27]

Q. Based on the responses above, PGE provided only eleven change orders related to just one project in the last three rate cases. How does this compare to Staff's request for change orders in the current rate case?

A. After receiving the PJFs for over 140 T&D projects included in our initial filing, Staff then requested change orders each T&D project included in our initial filing. Based on a high-level review to determine how this request could be filled, PGE discovered that this would have yielded thousands of change orders, and each one would need to be pulled manually from PGE's supply chain system. The request was not targeted to one or two specific projects, as was the case in the past with Staff's requests regarding Carty. Given the volume requested and the lack of specificity, we believe our objection to the burdensomeness of this data request was reasonable.

[26] *See*, Exhibit 1805.
[27] *See*, Exhibit 1805.

Nonetheless, PGE provided change orders associated with final purchase order amounts that exceed $750,000, plus all underlying documentation supporting those change orders, for at least 15 projects.

Q. If Parties are interested in understanding the material cost changes that occur on a project, how would they find this information?

A. Parties should look at the revisions on the PJF. The revisions on these forms represent the material changes to a project and leave out the immaterial changes that would be reflected in a review of every single change order. Additionally, the PJF will show changes to internal costs, which would not be reflected in change orders that are, by definition, applicable only to external vendors. For example, if there was an increase in PGE line crew labor, this cost increase would be documented in the PJF. It would *not* be documented in a change order, because PGE does not have change orders with itself.

Q. When Staff requested numerous change orders in this case, did PGE direct Staff to the PJFs and provide this explanation?

A. Yes. As mentioned above, PGE met with Staff several times to discuss various aspects of the capital budgeting and execution process, including how to interpret the PJFs.

VI. Summary

Q. Does PGE have a robust cost management and capital budget process?

A. Yes. As described in detail above, PGE has a rigorous top-to-bottom and bottom-to-top cost management and capital budget process. We have added several layers of control and review since the last rate case, including stage-gating and standardized cost estimation processes. While reading the PJFs may require some patience, they do provide robust documentation and explanation of changes to a project's budget. What is not shown in the PJF, but is described herein, are the layered levels of control and review for each project on a monthly basis, both within Portfolio Management and Project Management.

PGE takes seriously its obligation to provide safe and reliable service for our customers while balancing cost and affordability.

VII. Qualifications

Q. Mr. Ewers, please describe your qualifications.

A. I hold a Bachelor of Science degree in Accounting from Southern Oregon University and a Master of Business Administration from the University of Oregon. I have 20 years of experience in accounting and finance. I joined PGE in 2012, and I have held positions in the Finance Organization, the Project Management Office and in Data Strategy and Management. I am currently the Manager of Financial Planning and Analysis, and I have been in my role for two years.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
1801	PGE's Response to OPUC Data Request No. 889, Attachment B
1802	PGE's Response to OPUC Data Request No. 880
1803	Example of Old PJF
1804	Example of New PJF
1805	Data Requests from Previous Rate Cases

Exhibits 1801-1804 are
confidential and provided only in
electronic format. Exhibits
are subject to
General Protective Order 21-206

October 31, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE *Third Supplemental* Response to OPUC Data Request No. 131
Dated October 31, 2018

Request:

Please provide the following information for each project completed after July 2017. This request is ongoing and should be supplemented July 1, 2018, September 1, 2018, and November 1, 2018:

a. **Business Case**
b. **Project Charter**
c. **Project Budget**
d. **Actual Cost**
e. **Change Orders**
f. **Closing Documents**

Response (Dated March 29, 2018):

Based on a discussion with the OPUC Staff on March 19, 2018, the dates specified for supplemental responses are "file by" dates. Consequently, the information provided by those dates will be as of the most recent month closed for accounting purposes (e.g., the July 1 supplemental response will provide data as of May 31, 2018).

Please refer to PGE's response to OPUC Data Request No. 129, which includes details for completed projects after July 2017 and through December 2017 for requested items "a" through "e". Item "e" refers to approved changes in costs during the life of the project. Item "f" is all performed systematically in our PowerPlan Asset Management module after the projects are closed to plant.

Projects are triggered to close in PowerPlan in one of three ways. The first is a Monthly Close methodology, which uses this system control process to transfer the Projects' monthly capital expenditures to used and useful in the month incurred – this is used for the purchase of Furniture and IT Equipment. These costs are transferred to FERC account 101 and recorded to the correct 300-level FERC account for depreciation. The second methodology the PowerPlan system uses for control purposes is the Manual Blanket, for closing projects and capitalized costs when used and useful. The definition of a Blanket Project is discussed further in OPUC Data Request 132, and is similar to the Monthly Close. The capital expenditure costs in a project that falls into a Manual Blanket category are transferred to FERC account 106 and recorded to the correct 300-level FERC account for depreciation. The final method in PowerPlan uses for control purposes is Specific Close. Specific Close projects accrue costs in FERC account 107 while assets are being constructed. When the assets become used and useful, the project manager, or representative, inputs the date into PowerPlan, triggering the system to make the identification of the project and capitalized costs to create the journal entry to transfer costs from FERC 107 to FERC 106. As such, there is no formal closing documentation to provide.

PGE will provide 2018 actual updates as of May 31st, July 31st, and Sept 30th.

First Supplemental Response (Dated June 29, 2018)

Attachment 131-A provides the actual capital projects placed in-service through May and the updated close-to-plant forecast through December 31, 2018 by project.

Attachment 131-B provides project justifications for capital projects that were not part of PGE's original response but are now included in the updated forecast as of May 31, 2018.

PGE's response to AWEC Data Request No. 027 provides the project justifications for the projects forecasted to close-to-plant in PGE's original forecast.

Attachment 131-A and 131-B are protected and subject to Protective Order No. 18-047.

Second Supplemental Response (Dated August 30, 2018)

Attachment 131-C provides the actual capital projects placed in-service through July and the updated close-to-plant forecast through December 31, 2018 by project.

Attachment 131-D provides project justifications for capital projects that were not part of PGE's original response or in the First Supplemental Response, but are now included in the updated forecast as of July 31, 2018.

Attachment 131-C and 131-D are protected and subject to Protective Order No. 18-047.

Third Supplemental Response (Dated October 31, 2018)

Attachment 131-E provides the actual capital projects placed in-service through July and the updated close-to-plant forecast through December 31, 2018 by project.

Attachment 131-F provides project justifications for capital projects that were not part of PGE's original response or in the First Supplemental Response, but are now included in the updated forecast as of September 30, 2018.

Attachment 131-E and 131-F are protected and subject to Protective Order No. 18-047.

UE 335

Attachment 131-E

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Updated Close-to-Plant by Project Through Year-End 2018

UE 335

Attachment 131-F

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Project Justification Documents

March 29, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 129
Dated March 15, 2018

Request:

Please provide the original response to the Staff Plant Audit AIR 41 and 42 and update the response to the present date.

Response:

Attachment 129-A and 129-B provide the original responses to 2018 Staff Plant Audit AIR 41 and 42. The responses include actuals and project summaries for projects transferred to plant (additions) from January 2016 to September 2017.

Attachment 129-C provides projects and costs that were classified as plant-in-service during the fourth quarter of 2017.

Attachment 129-D provides Funding Project justifications of additional projects that are new or revised for the fourth quarter of 2017, which is PGE's most recently closed quarter with corresponding SEC filing (i.e., 10-K / 10-Q).

Attachments 129-B, 129-C, and 129-D, are protected and subject to Protective Order No. 18-047.

UE 335

Attachment 129-A

Provided in Electronic Format only

Original Response to 2018 Staff Plant Audit AIR 41 and 42

UE 335

Attachment 129-B

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-047

Original Response to 2018 Staff Plant Audit AIR 41 and 42

UE 335

Attachment 129-C

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-047

Q4 2017 Plant in Service Projects

UE 335

Attachment 129-D

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-047

Q4 2017 Project Justifications

March 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to OPUC Data Request No. 148
Dated March 6, 2017

Request:

Please provide all change orders related to the Carty project.

Response:

On March 16, 2017, OPUC Staff notified PGE that it withdraws its request in OPUC Data Request No. 148.

March 16, 2015

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 294
PGE Response to OPUC Data Request No. 171
Dated March 2, 2015

Request:

Please provide a list of any change orders associated with the Engineering, Procurement and Construction (EPC) contract for building the Carty Generating Station as of the date of responding to this data request. For each change order, please provide relevant information such as the date, dollar amount, requestor, etc. Please also provide a copy of each change order.

Response:

Attachment 171-A provides a list of the change orders associated with the EPC contract as well as a copy of each change order. Attachment 171-A is confidential and subject to Protective Order No. 15-036.

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UE 294

Attachment 171-A

Provided in Electronic Format only

Confidential and Subject to Protective Order No. 15-036

Change Orders

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Production

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Larry Bekkedahl
Stefan Cristea

December 2, 2021

Table of Contents

I. Introduction

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

A. My name is Larry Bekkedahl. I am the Senior Vice President of Advanced Energy Delivery. My qualifications appear at the end of PGE Exhibit 500.

My name is Stefan Cristea. My position at PGE is Senior Regulatory Analyst in the Rates and Regulatory Affairs department. My qualifications appear at the end of PGE Exhibit 700.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address certain issues and proposed adjustments raised by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to capital and O&M costs associated with PGE's generating units.

Q. What specific issues do you address in your testimony?

A. We address the following issues:

- Trojan Nuclear Decommissioning Trust (Section II-A)
- Faraday Repowering Project (Section II-B)
- Major Maintenance Accruals (Section II-C)

Q. How is the remainder of your testimony organized?

A. After this introduction, we have two sections:

- Section II: Parties' Proposed Adjustments
- Section III: Summary and Conclusion

II. Parties' Proposed Adjustments

A. Trojan Nuclear Decommissioning Trust

Q. What is the Trojan Nuclear Decommissioning Trust (NDT)?

A. PGE established the Trojan NDT to set aside funds that provide financial assurance for PGE's decommissioning obligations for the Trojan nuclear generating unit, as required by the Nuclear Regulatory Commission (NRC).

Q. Did Staff review the Trojan NDT costs and model?

A. Yes. Staff "analyzed the assets included in the trust and the Company's financial assumptions about the [Trojan Nuclear Decommissioning] trust" and found "no notable outliers in the financial assumptions used by the Company."[1] Staff concluded that no adjustment is needed for the Trojan NDT.[2]

Q. Please summarize the issues raised by AWEC regarding the Trojan NDT.

A. AWEC argues that PGE should refund to customers approximately $10.5 million that PGE received from the United States Department of Energy (DOE) between 2015 and 2019 as reimbursements associated with the Trojan Independent Spent Fuel Storage Installation (ISFSI).[3] Additionally, AWEC recommends that PGE refund to customers the $1.9 million Trojan annual accrual collected in 2020 on the basis that PGE did not add this amount to the Trojan NDT in 2020.[4]

Q. Is AWEC's recommendation that PGE refund $10.5 million in DOE reimbursements to customers reasonable?

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[1] Staff/500, Fjeldheim/46, lines 2-3 and 18-19.
[2] Staff/500, Fjeldheim/47.
[3] AWEC/100, Mullins/42.
[4] AWEC/100, Mullins/42.

A. No. AWEC's assertion that PGE retained the DOE reimbursements received between 2015 and 2019 is incorrect. In fact, as outlined below, PGE refunded the majority of the amounts received from the DOE directly to customers through Schedule 143 or through reduced customer annual contributions to the Trojan NDT.

Q. Is AWEC's recommendation that PGE refund the $1.9 million collected from customers reasonable?

A. No. As also explained below, PGE did not contribute the $1.9 million 2020 Trojan annual accrual collected from customers to the Trojan NDT in 2020 to fix an issue that occurred in 2019 when PGE effectively refunded the DOE reimbursements to customers twice: PGE refunded $2.9 million via Schedule 143 and also deposited $2.8 million in the trust.

Q. How does PGE fund the Trojan NDT?

A. PGE currently makes annual contributions of the DOE reimbursements and the Trojan annual accrual collected from customers. Prior to January 1, 2020, PGE contributed only the Trojan annual accrual collected from customers, while the DOE reimbursements were refunded to customers through Schedule 143.

Q. Please describe the history that resulted in PGE receiving DOE reimbursements related to Trojan?

A. As part of a 1983 contract between PGE and the DOE, PGE was required to pay the DOE 0.1 cents for each kilowatt-hour of electricity the Trojan plant produced. In return, DOE was required to take possession of the spent nuclear fuel generated at Trojan, beginning no later than January 31, 1998.

Because the DOE subsequently failed to take possession of the spent nuclear fuel, PGE filed suit to recover the extra costs incurred (i.e., damages) as a result of the DOE's breach of contract. Examples of the costs incurred include the construction of a dry storage facility and on-going spent fuel storage O&M costs.

PGE settled its lawsuit against the DOE in 2013, which resulted in the partial reimbursement of costs incurred through the end of 2009 for the Trojan partners. PGE's share of the settlement was approximately $50 million.[5] Furthermore, the settlement agreement established an administrative process for annual claim submissions for the recovery of allowable costs.

Q. Please describe the annual claim submission process?

A. Pursuant to the Settlement Agreement, PGE submits annual claims for damages resulting from the failure of the DOE to perform its contractual obligation to remove spent nuclear fuel. An annual claim (for the calendar year) is required to be filed no later than July 31st of the subsequent year (e.g., PGE has to file a claim by July 31, 2022 for costs incurred in 2021). Submission of a claim can be deferred up to three years if the amount of allowable costs to be claimed is less than $500,000.

Q. Please provide examples of allowable costs.

A. PGE can recover costs associated with ISFSI operations and maintenance, security and operations personnel, NRC inspections, Trojan NRC license renewal, electricity, or insurance.

Q. How did PGE treat the approximate $50 million received from the DOE pursuant to the Settlement Agreement?

A. PGE established Schedule 143 and refunded these amounts to customers over three years, between 2015 and 2017.

[5] Including an initial payment of $44 million and subsequent payment of $5.8 million from the DOE.

Q. Did PGE continue to refund annual DOE reimbursements to customers after the amortization of the $50 million was completed?

A. Yes. In accordance with the claims submission process established through the Settlement Agreement, PGE continued to submit annual claims and use Schedule 143 to refund the DOE reimbursements received from the DOE to customers, until Schedule 143 was set to zero beginning on January 1, 2020.

Q. What is the total amount that PGE refunded to customers via Schedule 143?

A. In total, PGE refunded to customers approximately $56.3 million between 2015 and 2020. PGE received approximately $63.3 million from DOE between 2013 and the end of 2020. The difference of approximately $7.0 million that was not refunded to customers via Schedule 143 is comprised of $6.6 million in reimbursements from DOE received in December 2019 and December 2020, and an additional $0.4 million residual balance of Schedule 143 as of December 31, 2019. PGE plans to transfer the $0.4 million residual balance to Schedule 105-Regulatory Adjustments, as noted in the Staff Memo recommending that the Commission approve PGE's request to set Schedule 143 prices to zero effective January 1, 2020 in Docket No. ADV 1046.[6]

Q. Why does AWEC recommend a $10.5 million adjustment when the amount that PGE has not refunded to customers via Schedule 143 is only $7.0 million?

A. AWEC calculates that PGE received approximately $13.3 million from the DOE between 2015 and 2019 and deposited only approximately $2.8 million in the Trojan NDT during the same period. Therefore, AWEC asserts that PGE retained a net of $10.5 million from the DOE reimbursements and should refund this amount to customers.[7] However, AWEC fails to

[6] See Staff Memo to Advice No. 19-27: https://edocs.puc.state.or.us/efdocs/HAU/adv1046hau101027.pdf
[7] AWEC/100, Mullins/41, lines 9-11

account for the fact that PGE refunded DOE reimbursements to customers via Schedule 143 until January 1, 2020, when the schedule prices were set to zero. In other words, AWEC's adjustment includes approximately $3.5 million that PGE already refunded to customers via Schedule 143.

Q. Please explain why PGE did not refund the $6.6 million reimbursements received from DOE in December 2019 and December 2020 to customers via Schedule 143.

A. PGE did not refund these amounts to customers because during PGE's 2019 general rate case in Docket No. UE 335 (UE 335), the Trojan annual accrual to be collected from customers was significantly reduced to account for the assumption that future DOE reimbursements would be transferred into the Trojan NDT instead of being refunded to customers via Schedule 143. Specifically, the Trojan model used to calculate the Trojan annual accrual in UE 335 included the assumption that the DOE reimbursements projected to be received in 2019 and 2020 in the amount of $4.3 million and $4.4 million, respectively, would be transferred into the trust. Consequently, the Commission adopted a Stipulation wherein parties agreed to significantly reduce the Trojan annual accrual collected from customers from $3.5 million to $1.9 million.

Because the amount customers pay into the Trojan annual accrual was reduced following UE 335, PGE customers are receiving the benefit of the $6.6 million in DOE refunds through these reduced annual accrual payments, rather than through direct refunds via Schedule 143. However, because of timing issues and an error that occurred in 2019, PGE has not yet transferred the $6.6 million DOE reimbursement into the Trojan trust. PGE is planning to add the funds to the trust in December 2021 or the first quarter of 2022. PGE has always intended to add these funds to the trust and has no intention of retaining these amounts as AWEC asserts.[8] Importantly, customers are already receiving the benefit of the $6.6 million reimbursement from DOE through reduced annual collections.

Q. Are customers harmed by the delay in adding the $6.6 million DOE reimbursement into the trust?

A. No. The Trojan model that calculates the annual accrual amount collected from customers assumes that DOE reimbursements are contributed to the trust when they are received. Thus, the Trojan annual accrual amount collected from customers accounts for the DOE reimbursements irrespective of when they are actually added to the trust. Additionally, even if PGE had added the $6.6 million to the trust in 2020, hence increasing the 2020 year-end balance, the increased balance would not have warranted a change in the Trojan annual accrual amount to be collected from customers, as we will explain in detail below.

Q. Did PGE stop refunding DOE reimbursements to customers via Schedule 143 in January 1, 2019, as modeled in UE 335?

A. No. We mentioned above that an error occurred in 2019. In 2019, PGE inadvertently did not set Schedule 143 prices to zero. As a result, PGE continued refunding the annual DOE reimbursement amount to customers even though PGE had also contributed the DOE reimbursement amount into the trust to decrease customers' contributions to the trust. Specifically, PGE refunded approximately $2.9 million through Schedule 143, <u>and</u> deposited a DOE reimbursement of $2.8 million into the Trojan trust,[9] which effectively double-counted the refund. PGE also transferred the $1.9 million Trojan annual accrual collected from customers in 2019 into the Trojan NDT. We reiterate that, as explained above, the $1.9

[8] AWEC/100, Mullins/41.
[9] The amounts are slightly different because the contribution to the trust reflects the actual DOE reimbursement while the amortization to customers via Schedule 143 includes an estimated component due to the timing of the reimbursement.

million annual accrual collected in 2019 represents a decrease from the prior accrual amount, and this decrease is based on the assumption that all DOE reimbursements are transferred to the Trojan trust instead of being refunded to customers. In other words, in 2019, customers received the benefit of the DOE reimbursement twice—through decreased contributions to the Trojan trust and through refunds via Schedule 143.

Q. Did PGE fix this issue in 2020?

A. Yes. PGE fixed the issue of the 2019 double refunding in two ways:

- First, because PGE incorrectly refunded approximately $2.9 million to customers in 2019, PGE did not contribute the $1.9 million collected from customers in 2020 to the trust and also did not contribute a portion of the 2021 annual collection; and
- Second, PGE proposed, and the Commission approved, setting the Schedule 143 prices to $0 effective January 1, 2020 in Docket No. ADV 1046, Advice No. 19-27 so that customers would not receive refunds through Schedule 143 in 2020 and subsequent years.

Q. Why didn't PGE contribute the $1.9 million collected from customers for the 2020 Trojan annual accrual to the trust?

A. PGE did not contribute this amount to the trust because, as noted above, PGE customers received the benefit of the DOE reimbursement twice in 2019. Specifically, PGE refunded approximately $2.9 million to customers in 2019, while also contributing to the trust both the DOE reimbursement and the 2019 Trojan annual accrual. To fix this issue, PGE deemed the $2.8 million DOE reimbursement added to the trust in 2019 to be a pre-funding of the 2020 annual customer collections and a portion of the 2021 annual customer collections.

Q. Could PGE have resolved the issue of double refunding by simply withdrawing the $2.8 million DOE reimbursement that was added to the Trojan NDT in 2019?

A. No. PGE can only withdraw funds from the trust to pay for qualified expenses incurred at the Trojan ISFSI. There have been other extraordinary instances when PGE has requested to withdraw funds from the Trojan NDT, such as when PGE received the $50 million from the DOE and the trust was significantly over-funded, but PGE would need to build a substantial record in support of a withdrawal request that includes proof that the trust provides financial assurance for future decommissioning costs. As we describe below, the trust is currently slightly underfunded so it would be difficult to support a withdrawal request.

Q. Did PGE withdraw funds from the trust in 2021 to cover Trojan ISFSI qualified expenses?

A. Yes. To date in 2021, PGE has withdrawn approximately $2.6 million from the Trojan trust to pay for qualified expenses incurred at the Trojan ISFSI in 2020 and 2021. Furthermore, PGE will withdraw an additional $2.8 million to cover other Trojan ISFSI 2021 expenses prior to year-end. Thus, in total, PGE will have withdrawn approximately $5.4 million from the Trojan NDT before year-end 2021.

Q. Would the Trojan annual accrual amount collected from customers have decreased if the end-of-year 2020 Trojan trust balances had included the $6.6 million DOE reimbursements received in 2019 and 2020 and the $1.9 million received from customers in 2020?

A. No. To determine the size of the Trojan annual accrual needed to give financial assurance for Trojan decommissioning costs, PGE uses a model that accounts for the latest Trojan NDT balances, expected rate of return on trust assets, projected decommissioning cost estimates, projected DOE reimbursements, tax expenses, and other parameters. Based on the analysis performed for this general rate case and the considerable uncertainty associated with the spent nuclear fuel at the Trojan site, PGE proposed to maintain the current annual accrual rate of $1.9 million, despite the fact that the Trojan model results in a Trojan trust deficiency starting in 2056. This projected trust deficiency would have warranted a request to increase the Trojan annual accrual rate and adding approximately $8.5 million ($6.6 + $1.9 million) to the end-of-year 2020 Trojan trust balance would only shift the year when the trust becomes deficient to 2057. The Trojan model with an adjusted 2020 balance to include these amounts is provided in supporting work papers to this testimony.[10] Also, as noted above, PGE will have withdrawn approximately $5.4 million before year-end 2021 from the Trojan NDT, and thus, the trust balance will only increase by a net of approximately $1.2 million after PGE contributes the $6.6 million to the trust.

Q. Why didn't PGE ask for an increase to the Trojan annual accrual in this general rate case (GRC)?

A. PGE did not propose an increase to the Trojan annual accrual to mitigate the impact on customer prices and because there are still approximately 38 years until the current NRC license expires. For regulatory purposes, PGE uses the NRC license expiration year as the assumed time when the Trojan decommissioning will be finalized. However, at this time there is no information to suggest that the DOE can take possession of the Trojan spent fuel in the near future.

Q. Did AWEC propose other adjustments related to the Trojan annual accrual?

[10] See Work paper "2022 Trojan NDT Accrual", tab "Return – 2022 GRC", range CB255:CB258 for the fund deficiency amounts with a 2020 end of year balance that includes 2019 and 2020 DOE reimbursements and 2020 customer collections. The updated 2020 end of year balance is provided in tab "Financial Assumptions", cells X85 and X86.

A. Yes. AWEC recommended that PGE refund to customers an additional $1.9 million on the basis that PGE double collected the Trojan annual accrual through base rates and through Schedule 136.[11] Schedule 136 is the Community Solar Program Cost Recovery tariff schedule and does not contain any Trojan-related collections. This issue was resolved in the Second Stipulation with no adjustment to PGE's proposed revenue requirement in this case.

Q. Please summarize your response to AWEC's recommendations.

A. AWEC's recommendations regarding the Trojan NDT are not reasonable. AWEC ignores several key facts regarding the Trojan NDT, including:

- PGE refunded DOE reimbursements to customers until Schedule 143 prices were set to zero in January 2020;
- Customers currently receive the benefit of lower Trojan annual accruals due to the assumption that DOE reimbursements are contributed to the trust, irrespective of when the transfers of funds to the trust actually occur; and
- PGE proposed to maintain the current annual accrual rate of $1.9 million, despite the fact that the Trojan model suggests the annual accrual amount should be increased since the Trojan trust will be deficient starting in 2056**.**

In conclusion, PGE recommends that the Commission reject AWEC's adjustments on the basis that they ignore the key elements explained above and contradict the approach agreed-upon in UE 335 under which DOE reimbursements are used to reduce customers' contributions to the Trojan trust, rather than being refunded to customers directly.

B. Faraday Repowering Project

Q. Please summarize the issue raised by parties regarding the Faraday Repowering Project.

[11] AWEC/100, Mullins/44.

A. Both Staff and AWEC raised concerns regarding the Faraday Repowering Project:

- Staff argues that PGE did not consider all options available at the time the decision was made to repower Faraday. Additionally, Staff claims that PGE mismanaged the contracting of the project and over-relied on "known estimated construction costs"[12] when calculating project Net Present Values (NPVs), and this resulted in project construction delays and increased costs.
- AWEC argues that "the completion of this project in time for the rate effective date in this proceeding is highly uncertain, particularly considering the ongoing global supply chain problems"[13] and that customers "should not be responsible for any of the excessive costs[.]"[14]

Q. What recommendations do Staff and AWEC provide?

A. AWEC recommends that the costs associated with the Faraday Repowering project be excluded from the 2022 revenue requirement forecast.[15]

Staff makes the following recommendations:

- PGE should file an attestation that the Faraday plant has been placed into service prior to April 30, 2022.[16]
- PGE should include significant capital investments such as repowerings in integrated resource plan (IRP) filings going forward and fully demonstrate the prudency of its investments in future filings.[17]

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[12] Staff/1000, Enright/21, at 15-19
[13] AWEC/100, Mullins/20, at 10-12.
[14] AWEC/100, Mullins/21, at 9-10.
[15] AWEC/100, Mullins/21.
[16] Staff/1000, Enright/14.
[17] Staff/1000, Enright/16.

- A 10 percent disallowance of the general construction cost increase agreed upon by PGE and the general contractor in the contract amendment executed in May 2019.[18]
- A disallowance of **[Begin Confidential]** [redacted] **[End Confidential]** in costs related to delays in project construction. However, Staff also recommends that the Commission allow PGE to recover legal and accountancy costs associated with contract renegotiations and to keep any liquidated damages payable under the construction contract.[19]

Q. Does AWEC recommend a cost disallowance?

A. No. AWEC only recommends that the Faraday repowering project costs be removed from the 2022 revenue requirement. If this occurred, PGE would be able to request cost recovery in a future proceeding, when the project has been placed in service and costs can be reviewed for prudency.[20]

Q. Do you agree with the adjustments and recommendations proposed by Staff and AWEC?

A. No. The Faraday repowering costs were prudently incurred, and PGE should be permitted to recover the full cost. Because the most recent update to the project schedule provides for a fourth quarter 2022, in-service date, however, PGE requests that the Commission adopt a tariff rider to allow PGE to timely recover the prudently incurred costs. At the end of our testimony, we also discuss other approaches to recovery that the Company could pursue if the Commission does not accept the proposed tariff rider.

[18] Staff/1000, Enright/21.
[19] Staff/1000, Enright/25.
[20] AWEC/100, Mullins/21, at 17-19.

Q. Please explain the structural issues at Faraday that led PGE to pursue the repowering project.

A. PGE made the decision to repower Faraday because of major safety and operational concerns. The most significant are:

- The Faraday facility lacked seismic reinforcement to ensure structural integrity during a seismic event.
- 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 outage duration and cost for cleaning, repair, or replacement of structures and equipment due to flooding was expected to significantly impact costs and plant reliability. Furthermore, the generator floor and windows of the powerhouse were below extreme high-flow event water levels.
- Numerous pieces of plant equipment had exceeded their useful lives, which was expected to impact plant availability and reliability and require increased operation and maintenance costs.
- The age of plant equipment was also expected to create challenges in predicting the type and duration of unplanned outages due to limited access to skilled craft, parts, and materials.
- Extreme high-flow events were expected to become more frequent in the region and the response to and preparation for predicted high-flow events would require redeployment of labor and materials to shut down and prepare the facility for flooding at increased expected costs.

Q. Please respond to Staff's argument that PGE did not consider all options available at the time when the Faraday Repowering project was pursued.[21]

A. While Staff noted in their testimony that PGE *did* actually consider all the options available, except the full decommissioning of the Faraday plant,[22] Staff asserts that "PGE missed the opportunity to assess the value that the imperfect projects might create."[23] It is not obvious what Staff means since PGE explained during discovery[24] that some of the options considered were not viable because they would incur similar costs but would not address the operational safety and reliability issues at Faraday.

Q. What options did PGE consider to ensure reliable and safe plant operations at Faraday?

A. PGE considered the following options:

1. Status Quo: Do nothing and continue to maintain original powerhouse and turbine-generators.
2. Retrofit the existing powerhouse structure and maintain original turbine-generators.
3. Replace the powerhouse structure and maintain original turbine-generators.
4. Replace the powerhouse structure and install new turbine-generators.

Q. Why didn't PGE consider decommissioning Faraday, instead of repowering?

A. Faraday has been an important component of PGE's generation portfolio since 1907, providing non-emitting, firm capacity. As we explained in our direct testimony,[25] Faraday benefits customers because it helps meet PGE's capacity needs and provides resource diversity in meeting our carbon-free energy requirements. Repowering Faraday ensures that

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[21] Staff/1000, Enright/18.
[22] Staff/1000, Enright/16, Confidential Figure 3 – Scenarios considered by PGE in 2016, at lines 10-21
[23] Staff/1000, Enright/18, at lines 20-21.
[24] *See* Staff/1002, Enright/7 (PGE's response to OPUC Data Request No. 588, part c)
[25] PGE/700, Jenkins-Cristea/5.

customers will have reliable access to this valuable resource for decades to come**.** The Faraday Repowering project will provide PGE access to firm capacity, which is critical given the regional capacity shortage. As described in PGE Exhibit 700,[26] over the last two decades, a significant amount of firm and dispatchable generation (i.e., coal and gas plants) has been retired or decommissioned within the Western Electricity Coordinating Council (WECC) region. These resources have not been replaced in kind. The reduction in regional firm and dispatchable resources is causing a regional capacity shortage which manifests in the form of extreme price volatility and increases the number of scarcity price events during weather driven load excursions or other market events. For example, the Mid-C power market exhibited this type of behavior during the 2021 heat events that led Mid-C market power prices to settle as high as $489/MWh. Access to reliable generation from Faraday will help PGE's customers weather such scarcity price events.

Faraday is particularly valuable because it is a non-emitting capacity resource. As explained in PGE Exhibit 1300, PGE's decarbonization strategy aligns with the aggressive emissions reductions required by Oregon law. PGE needs resources like Faraday to achieve significant emissions reductions while maintaining reliability. The carbon reduction requirements under HB 2021 makes retention and repowering of the Faraday hydro project even more critical as we seek to eliminate carbon emissions from our power supply portfolio by 2040. Because of the significant benefits Faraday provides—and will continue to provide for decades to come—PGE did not consider the decommissioning of Faraday to be a beneficial option for customers.

Q. Which of the options listed above were evaluated by PGE from an economic perspective?

[26] PGE/700, Jenkins-Cristea/5.

A. In 2016, prior to selecting the repowering as the best option, PGE evaluated the NPVs for maintaining the status quo and for the repowering options.

Q. What was the result of the economic analysis performed in 2016 that compared the status quo with the repowering option?

A. The repowering scenario had a greater NPV than the status quo scenario. PGE relied on this analysis and several other factors when giving the Faraday Repowering project contractor notice to proceed. Exhibit 1901 provides the economic analysis.[27]

Q. Why didn't PGE evaluate the NPV of the other two alternatives?

A. PGE did not consider retrofitting or replacing the powerhouse structure and maintaining the original turbine-generators to be viable or prudent options because PGE would have incurred significant costs without mitigating the flood risk or addressing the age of the existing generator equipment. Therefore, an NPV analysis was not completed because the options were not otherwise feasible.

Q. Aside from the results of PGE's economic analysis, what other factors did PGE consider when selecting the Faraday repowering from the aforementioned alternatives?

A. As described above, the Faraday plant was having significant structural issues that impacted safety and plant operations. PGE pursued the plant repowering to: 1) avoid frequent and unpredictable maintenance issues due to equipment age and flooding, 2) improve operational safety, 3) improve operational reliability, 4) increase plant generation and capacity, 5) capture renewable production tax credits, and 6) ensure PGE has access to a clean, non-emitting energy and capacity resource to support Oregon's and PGE's decarbonization goals.

[27] See tab "Assump", cell O24 for the delta between the two scenarios NPVs.

Q. Staff argues that PGE approved the Faraday Repowering "in a rush" to ensure the repowering project was eligible for production tax credits (PTCs) and that "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".[28] How do you respond to this?

A. Staff's conclusions are purely speculative and not based on the evidence PGE provided through discovery. While PGE agrees that it was important for the project to be approved in time to meet the eligibility for PTCs for the benefit of customers, PGE did not approve the project "in a rush" and without careful attention to all project details. As described in this testimony thus far, PGE did a thorough review, analyzing multiple options and performing economic analysis before the Faraday Repowering Project was selected. Moreover, PGE is not a construction company. Therefore, to determine preliminary cost estimates and the most beneficial repowering option for customers, PGE engaged Kleinschmidt - a reputable company with more than 50 years of experience in hydropower facilities, from modernization and rehabilitations to building new facilities - to perform a comprehensive powerhouse upgrade study for Faraday.

Q. Please provide a brief description of the purpose of the Kleinschmidt study.

A. PGE commissioned the Faraday powerhouse upgrade study to support the economic evaluation of whether a comprehensive upgrade of the facility would be a more economic investment than maintaining the status quo and undertaking the multiple major capital projects that were needed to address major repairs and renovations required to ensure continued safe and reliable operations of the original Faraday hydro facility (Units 1 through 5). The repairs

[28] Staff/1000, Enright/20.

and renovations that would have been required if the status quo was maintained included rebuilding the powerhouse superstructure, overhauling turbines, and upgrading the controls and electrical system. The study was finalized in April 2016.

Q. Staff criticizes PGE for relying on the estimate in the Kleinschmidt study.[29] Please describe the Kleinschmidt cost estimate.

A. Kleinschmidt developed a breakdown of project components to create an opinion of probable construction costs based on the best information known at that time, consistent with a Class 4 level, as defined by the AACE International classification system for the hydropower industry. A Class 4 level is defined as a cost estimate at a project maturity level of 1 to 15%. **[Begin Confidential]** [redacted] **[End Confidential]**.

Q. Staff notes that the general construction cost estimate increased significantly from the Kleinschmidt initial estimate.[30] Please explain how the Kleinschmidt estimate compares to the increased estimate Staff references.

A. As noted above, in 2016, Kleinschmidt estimated the general construction costs would be **[Begin Confidential]** [redacted] **[End Confidential]**. The original project cost estimate was created during the planning phase of the design work with the best information known at the time, and PGE used the estimate as a basis for requesting funding to move forward with the powerhouse design work. Due to the high complexity, uniqueness, and uncertainties inherent in the repowering of a 100+ year-old hydro facility, PGE understood that overall costs would

[29] Staff/1000, Enright/19.
[30] Staff/1000, Enright/19.

be evaluated at 30% design and 90% design to determine whether to re-evaluate budget and scope after receiving actual bids. In 2018, when the project was at 90% design, PGE executed the negotiated Guaranteed Maximum Price contract with the selected Construction Manager/General Contractor (CM/GC). **[Begin Confidential]** [redacted] **[End Confidential]**. Subsequently, the contract was amended in May 2019 and November 2020. As PGE completed more of the project design and gained more detailed information, including obtaining actual bids, the estimated cost increased, but this does not mean that the Kleinschmidt estimate was unreliable or that PGE should not have relied on the informed opinion of the reputable expert PGE had retained.

Q. Staff is proposing a disallowance of approximately [Begin Confidential] [redacted] **[End Confidential] to general construction costs to reflect "PGE's over-reliance on the 'known' estimated construction costs" and because PGE's financial and technical experts made "no attempt to verify or investigate the data used in its NPV calculation."[31] Do you agree with Staff's adjustment?**

A. No. Staff's proposed adjustment is based on unsupported assertions. In the planning phase, PGE commissioned a complex and detailed study from a reputable company, using the best information known at the time, to determine the repowering option that provided the most benefit to customers. But PGE did not simply obtain the Kleinschmidt estimate and then proceed with the project without looking back. Rather, as described in this testimony, we conducted a thorough review of project alternatives and an NPV analysis to support the decision to select the Faraday Repowering project.

[31] Staff/1000, Enright/21, lines 15-20

Q. Does Staff propose additional cost disallowances related to the Faraday Repowering Project?

A. Yes. Staff is proposing an additional **[Begin Confidential]** [redacted] **[End Confidential]**.[32]

Q. What are Staff's arguments in support of this adjustment?

A. Staff proposes this adjustment on the basis that PGE mismanaged the contracting for the construction project. Specifically, Staff argues that PGE missed the opportunity **[Begin Confidential]** [redacted] **[End Confidential]**. Furthermore, to support the argument that PGE should have **[Begin Confidential]** [redacted] **[End Confidential]**, Staff draws a parallel between the original general construction contract executed in 2018 for Faraday and a draft power purchase agreement (PPA) submitted by PGE in Docket No. UM 1773 in July 2017.[33]

Q. Do you agree with Staff's proposed disallowance?

A. No. As noted above, Staff's proposed disallowance is based on Staff's view that PGE mismanaged the execution of the original contract by **[Begin Confidential]** [redacted] **[End Confidential]**. However, as PGE explained during discovery **[Begin Confidential]** [redacted]

[32] Staff/1000, Enright/25.
[33] Staff/1000, Enright/23.

[redacted] **[End Confidential]**[34]

Q. Staff argues that the project cost increased due to PGE's failure to [Begin Confidential] [redacted] [End Confidential], and Staff references a draft PPA to support this argument.[35] Is Staff's reliance on the draft PPA reasonable?

A. No. First, the two agreements are not analogous in that they have substantially different scopes and terms. One is a power purchase agreement and the other is a construction agreement with a general contractor. However, even when compared, the construction agreement contains similar protections to the draft PPA. Specifically, while the draft PPA referenced by Staff included **[Begin Confidential]** [redacted] **[End Confidential]**

[34] See PGE's response to OPUC Data Request No. 825, provided by Staff in Exhibit 1002, page 47.
[35] Staff/1000, Enright/22-23 n.66.

Q. Why didn't PGE add additional [Begin Confidential] [redacted] **[End Confidential]?**

A. As noted above, the original contract **[Begin Confidential]** [redacted][36] **[End Confidential]**

Q. Why did the project schedule experienced delays?

A. Aside from construction issues encountered with the general contractor, the Faraday Repowering Project construction was impacted by the extraordinary events that occurred during the 2020 and 2021 timeframe. Specifically, the construction schedule and cost were impacted by the 2020 wildfires, flooding events in 2020 and early 2021, the February 2021 ice storm, and by the ongoing COVID-19 pandemic which caused the construction site to shut down for safety reasons when there was a COVID-19 outbreak. These events were not foreseeable when PGE entered the original construction contract.

Q. Please elaborate how these events impacted the Faraday Repowering Project.

[36] Staff/1000, Enright/24, lines 3-4 and 14-15.

A. The concurrent occurrence of these events resulted in significant strains put on the work crews and the progress of the project. Below are additional details regarding how these events impacted the Faraday Repowering Project:

- The 2020 wildfire at the site resulted in site evacuation and also in loss of power at the site that caused hydro pumps to stop working, which in turn resulted in the flooding of the construction site and work needing to be paused. Exhibit 1902 provides images that show the wildfire impact.
- The construction site was also flooded due high river flows in January 2020, December 2020, and January 2021, causing delays in the project schedule. Exhibit 1903 provides images that show the January 2020 site flooding, Exhibit 1904 provides images that show the December 2020 site flooding, and Exhibit 1905 provides pictures that show the January 2021 site flooding.
- The February 2021 ice storm resulted in loss of power and unsafe work conditions causing the shutdown of the construction site for a limited period of time.
- The COVID-19 pandemic caused equipment vendors to delay the production of parts which in turn introduced delays in project schedule. The COVID-19 pandemic also resulted in uncertainties regarding health safety, loss of qualified personnel, and caused the construction site to shut down multiple times for health safety reasons due to virus outbreaks.

In isolation, each of these events may not have had a significant impact on the project, however, the culmination of all of these events ultimately severely impacted the project.

Q. What specific actions did PGE take to keep the project schedule on track?

A. **[Begin Confidential]** [redacted]

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

- [redacted]

- [redacted]

- [redacted]

• [redacted] **[End Confidential]**

Q. Please summarize PGE's position on the Faraday Repowering Project.

A. Repowering Faraday benefits customers by ensuring access to a reliable non-emitting capacity resource for decades to come. PGE diligently assessed all viable options prior to making the decision to repower Faraday, a process that included hiring a reputable consultancy company to perform a powerhouse upgrade study and economic analysis. After the repowering decision was made, based on economic analysis and other factors described in this testimony, PGE hired a general contractor to perform the work. **[Begin confidential]** [redacted] **[End Confidential]**

PGE should be permitted to recover the full cost of the Faraday Repowering Project after the project is placed in service.

Q. What is the current expected in-service date for the Faraday Repowering Project?

A. The Faraday Repowering Project estimated in-service date is now fourth quarter 2022. The Faraday Repowering Project is now approximately 70 percent completed and **[Begin Confidential]** [redacted] **[End Confidential]** to complete the remaining approximately 30 percent of the project work.

Q. How does PGE intend to seek recovery of the Faraday Repowering Project prudently incurred costs?

A. As noted above, the current estimated in-service date is after April 30, 2022, the cut-off date to include capital investments in the rate base for this GRC. The options for PGE to request recovery of prudently incurred costs for the Faraday Repowering Project are:

1. Commission approval of a tariff rider in this GRC: The tariff rider would allow PGE to include Faraday Repowering Project prudently incurred costs in customer prices after PGE files an attestation by an officer that the project was placed in service. If the Faraday Repowering Project is not completed and in-service by fourth quarter , 2022, PGE will file a new ratemaking request seeking the inclusion of project costs in rates.
2. Deferred Accounting Application: Request deferred accounting treatment to allow recovery of costs after the Faraday Repowering Project is placed in-service.

3. Filing a single-issue rate case: Request a narrow rate case that reviews only the prudency of the Faraday Repowering Project to allow PGE to include the capital investment in the rate base and customer prices.
4. Filing a new general rate case and including the Faraday Repowering Project capital investment in the rate base and customer prices.
5. File for recovery via PGE Schedule 122 (Renewable Resources Automatic Adjustment Clause): The Faraday Repowering Project may qualify for a Renewable Resources Automatic Adjustment Clause filing since the expected incremental generation is eligible for Renewable Portfolio Standard compliance.

Q. Which cost recovery option does PGE propose in this proceeding?

A. PGE is proposing that the Commission allow a tariff rider for the recovery of prudently incurred costs for the Faraday Repowering Project when the project is placed in-service. Under this proposal, prices recovering the costs of the Faraday Repowering Project would become effective shortly after a PGE officer has provided an attestation that the project has been place in service, which is expected to be in the fourth quarter of 2022. It should be noted that beginning January 1, 2022, PGE customers will receive forecasted Faraday Repowering Project energy and PTC benefits that reflect the fourth quarter, 2022 expected in-service via updated Schedule 125 (Annual Power Cost Update) prices in Docket No. UE 391. It is thus appropriate under the general principle of matching costs and benefits for the Commission to allow for the recovery of project costs upon the in-service of the Faraday Repowering Project.

C. Major Maintenance Accruals

Q. Did any party object to PGE's proposed 2022 major maintenance accruals?

A. No, Parties did not take issue with PGE's proposal to create a major maintenance accrual for the recovery of costs associated with KB pipeline integrity assessment.[37] Staff does propose to amortize the related costs over a 10-year period, however, instead of the 5-year period proposed by PGE.

Q. Do you agree with Staff's proposal?

A. While we do not oppose spreading these costs over a 10-year period, we would note that the resulting annual cost reduction of approximately $70,000 is *de minimis.* Additionally, spreading costs over a 5-year period, as proposed by PGE, is consistent with the approved major maintenance accrual calculation methodology used for our gas thermal plants.

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[37] See description in PGE Exhibit 700, at page 20.

IV. Summary and Conclusion

Q. Please summarize your position regarding the issues identified by Parties.

A. We recommend the Commission reject AWEC's proposals regarding the Trojan NDT on the basis that they are contrary to the approach adopted in UE 335 to use the DOE reimbursements to reduce Trojan annual accruals collected from customers, rather than refunding the DOE reimbursements to customers via Schedule 143.

With respect to the Faraday Repowering Project, we do not agree with Staff's criticisms regarding the project or with Staff's proposed disallowances. Decommissioning Faraday was not a viable option for customers given the significant benefit Faraday provides and the importance of retaining diverse and clean power supply resources to meet PGE and Oregon's decarbonization goals. PGE diligently assessed all viable options prior to making the decision to repower Faraday, a process that included hiring a reputable consultant to perform a powerhouse upgrade study and performing economic analysis. After the repowering decision was made, PGE hired a general contractor to perform the work and proactively addressed delays in the construction schedule. Because the Faraday Repowering Project in-service date is now expected in the fourth quarter of 2022, PGE proposes that the Commission adopt a tariff rider to allow PGE to recover the costs of the project once it is in-service.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
1901C	Faraday Repowering Project Net Present Value Analysis
1902C	2020 Wildfire Impact at the Faraday Construction Site
1903C	January 2020 Faraday Construction Site Flooding
1904C	December 2020 Faraday Construction Site Flooding
1905C	January 2021 Faraday Construction Site Flooding

Exhibits 1901 - 1905 are
confidential and provided only in
electronic format. Exhibits
are subject to
General Protective Order 21-206

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Transmission & Distribution

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Larry Bekkedahl
Bradley Jenkins

December 2, 2021

Table of Contents

I. Introduction

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

A. My name is Larry Bekkedahl. I am the Senior Vice President of Advanced Energy Delivery at PGE. My qualifications were previously provided in PGE Exhibit 500.

My name is Bradley Jenkins. I am the Vice President of Utility Operations at PGE. My qualifications were previously provided in PGE Exhibit 700.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to address certain issues and proposed adjustments raised by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff), and the Alliance of Western Energy Consumers (AWEC) (collectively, Parties) with respect to PGE's investments in transmission and distribution capital projects.

Q. What specific issues do you address in your testimony?

A. We address the following issues:

- Section II - Wildfire Mitigation (WM) and Vegetation Management (VM)
    - We oppose Staff's proposed mechanism to reduce funding for wildfire mitigation based on purported vegetation management violations identified by OPUC Safety Staff. First, wildfire mitigation and vegetation management are two distinct programs each with their own unique goals. Second, PGE has demonstrated, and Staff has agreed with, the prudence of our proposed investment in wildfire mitigation. The full amount should be included in base rates and not be subject to a deferral and penalties as proposed by Staff. Third, the Commission should adopt an Automatic Adjustment Clause (AAC) to provide for timely recovery of wildfire

mitigation costs as required by Senate Bill (SB) 762. Finally, as extensively documented in other forums, PGE does not agree with OPUC Safety Staff's methodology to identifying "probable" violations, which further undermines the viability of using this metric.

- Section III - Prudence of Advanced Distribution Management System (ADMS) Capital Investments
    - We oppose Staff's recommended disallowance of $26.0 million of capital ADMS costs. We provide detailed documentation of the prudence of PGE's investments in ADMS capital projects.
- Section IV - Prudence of Transmission and Distribution Capital Investments
    - We oppose Staff's recommended disallowances of certain Transmission and Distribution (T&D) projects. We provide detailed explanations of the prudence of PGE's investments in these projects.
    - We address AWEC's concerns about large customer load increases in the Hillsboro area.
- Section V - Summary and Conclusion

II. WILDFIRE MITIGATION AND VEGETATION MANAGEMENT

Q. Please summarize the key points in Staff's Opening Testimony on Wildfire Mitigation and Vegetation Management.

A. Staff made three primary points in their Opening Testimony. First, without cause or explanation, Staff grouped the wildfire mitigation (WM) program and vegetation management (VM) program together and treated them as one program throughout Opening Testimony.[1] Second, Staff expressed concern about the perceived lack of multi-year budgeting within the WM program.[2] Finally, despite finding "no issues with any part of the Company's overall proposed WMVM capital or O&M expenses," Staff proposed to withhold $3 million of WMVM O&M expenses out of base rates, to be accessible via a new deferral account and complex performance-based rate mechanism (PBRM) that include no incentives but would include numerous penalties intended to decrease the amount of prudently incurred expenses PGE can recover.[3]

Q. Is it appropriate to group the WM program and VM program together as one item?

A. No. Each program is distinct with its own unique purpose, functions, and deliverables. The WM program works to identify and mitigate risks of electric supply facilities creating or contributing to a wildfire event. The WM program focuses on identifying areas with high risk of wildfire due to electric supply facilities in the system and actions necessary to mitigate the risk of facilities creating or contributing to a wildfire event in high risk fire zones, including investigating how to increase the resiliency of and reduce damage to assets due to wildfires.

[1] Staff/600, Dlouhy/15.
[2] Staff/600, Dlouhy/24.
[3] Staff/600, Dlouhy/18.

By contrast, the VM program manages vegetation to keep the entire system safe and reliable, not just wildfire risk areas. The VM program focuses exclusively on vegetation management and is comprised of five elements: 1) line-clearance tree trimming in accordance with Oregon Administrative Rules (OARs), National Electric Safety Code (NESC), and OPUC Division 24 Safety Standards; 2) PGE's Facility Inspection and Treatment to the National Electric Safety Code Program (FITNES); 3) outage and storm response; 4) enhanced vegetation management (EVM); and 5) Advanced Wildfire Risk Reduction (AWRR). The fifth element, AWRR, provides enhanced vegetation management in high risk fire zones.

AWRR is a new VM program that reduces the risk of wildfire associated with vegetation near utility assets. AWRR is part of PGE's 2021 Wildfire Mitigation Plan and will focus initially on vegetation in the seven Public Safety Power Shutoff (PSPS) zones PGE identified as of the date of the rate case filing. PGE's Wildfire Mitigation Plan provides detailed protocols for managing vegetation in these high risk fire zones. AWRR costs are included in the vegetation management budget because it provides enhanced vegetation management in high risk fire zones.

Q. Why did Staff decide to combine two distinct programs, wildfire mitigation and vegetation management, into one?

A. Staff provided no explanation for combining the two programs in their Opening Testimony. It is unclear if Staff combined them simply for ease of discussion or if Staff does not understand the fundamental differences between the programs.

Q. How do you respond to Staff's concept of treating wildfire mitigation and vegetation management as one program?

A. We reject Staff's assumption that the WM and VM programs can reasonably be treated as one program. While there are some similarities between the programs, they each have distinct purposes, goals, and deliverables, and need to remain separate programs. Combining the two programs would result in misalignment of goals and results. Therefore, in the remainder of our reply testimony, we will refer to each program individually, as we did in our direct testimony.

Q. Why did PGE not provide multi-year budgeting for the WM and VM programs in this rate filing?

A. This rate case filing is based on a 2022 test year revenue requirement. This is the same methodology PGE has used in past rate cases and is consistent with the future test year methodology this Commission allows utilities to employ. PGE forecasts O&M costs for 2022 to calculate the revenue requirement that is included in the rate case filing. The rate case does not incorporate budget forecasts or project work plans beyond the test year. In the case of wildfire mitigation, there are several processes outside of the rate case filing where this information may be provided, such as the WM Plan PGE is required to file. These budgets are not, however, relevant to the ratemaking methodology employed by the Commission in general rate cases (GRCs), which is designed to identify an appropriate revenue requirement using a future test year.

Q. Before getting into the details of Staff's PBRM proposal, please describe your concerns with the metric Staff uses to adjust the earnings review threshold.

A. Staff proposes imposing basis point reductions on PGE's cost recovery based on the "number of vegetation management violations identified by the PUC's [S]afety Staff."[4] Even if a

[4] Staff/600, Dlouhy/28.

PBRM mechanism like the one proposed by Staff were appropriate, which is it not, the proposed enforcement mechanism would be flawed and unfair to PGE. As described extensively in other forums, PGE has strong reservations about the methodology OPUC Safety Staff use to identify what they call "probable violations." Even in the context of an otherwise appropriate PBRM it would be inappropriate to use a metric of *probable* violations, based on a questionable methodology, to adjust the amount of prudently incurred costs PGE can recover. For the ease of discussion, we will use the term "violations" as shorthand throughout the rest of the testimony.[5]

Q. Please summarize Staff's PBRM proposal.

A. Despite Staff finding "no issues with any part" of our proposed wildfire mitigation and vegetation management capital and O&M expenses, Staff proposed withholding $3 million from the overall budget and establishing a deferral account to place up to $6 million in incremental or decremental costs compared to base rates. Any deferred costs would be subject to a subsequent prudence review and amortization. Staff also proposed a series of penalties to decrease the amount of prudently incurred costs PGE could recover.[6] There would be a prudence review of the wildfire mitigation and vegetation management expenses and an earnings test. The earnings threshold would vary based on the number of *vegetation management* violations identified by OPUC Safety Staff and the number of violations that include climbable trees. This methodology would apply to the first $6 million of incremental costs over and above the expense level in the deferral account.[7] This first $6 million is

[5] If the Commission were to adopt Staff's PBRM, PGE would ask the Commission to include language in its order that requires the perceived violation to be validated before any penalties can be imposed.
[6] Staff/600, Dlouhy/18.
[7] Staff/600, Dlouhy/26-27.

inclusive of the $3 million Staff has proposed to withhold. Incremental costs beyond the first $6 million would be subject to a different earnings test.[8]

For the first $6 million of incremental prudently incurred wildfire mitigation and vegetation management costs, the amount of prudently incurred costs that could be recovered by PGE would decrease based on a series of penalties proposed by Staff. The first set of penalties would be based on the annual number of vegetation management violations identified by OPUC Safety Staff. For example, if the OPUC Safety Staff identified between 151 and 300 violations, then PGE could recover prudently incurred costs up to its Commission authorized ROE *minus* 100 basis points. As the number of violations increased, the basis point reduction would increase.[9] On top of this, Staff proposed an additional 50 basis point reduction to its earnings test threshold should that violation occur within a high risk fire zone (i.e., Tier 2 and Tier 3 areas).[10] Finally, Staff proposed an additional penalty based on climbable vegetation metrics. If PGE failed to address "any identified violation for climbable trees within 30 days of receiving" notice from OPUC Safety Staff, then the applicable earnings thresholds would be reduced by an *additional* 50 basis points.[11]

Q. What are PGE's concerns regarding the ROE thresholds?

A. PGE finds the ROE thresholds based on these violations to be punitive. More importantly, the application of the ROE thresholds to prudent costs included in this 2022 test year rate case is inappropriate because cost of capital, including ROE, has already been settled by the parties. Withholding costs identified as prudent by Staff and only allowing recovery after applying

[8] Staff/600, Dlouhy/27.
[9] Staff/600, Dlouhy/28-29.
[10] Staff/600, Dlouhy/29.
[11] Staff/600, Dlouhy/30.

ROE thresholds under a new mechanism misaligns the risk and reward associated with the settlement that was already achieved by the parties.

Q. What is the relationship between vegetation management violations across PGE's service territory and PGE's investment in mitigating wildfire risk?

A. There is no inherent relationship between the two. Vegetation management occurs across PGE's entire service area and PGE proactively manages vegetation in order to keep the entire system safe and reliable under all conditions, including during ice, snow, or windstorms. By contrast, PGE's WM program targets high risk fire zones (i.e., Tier 2 and Tier 3 zones) and implements a variety of preventative measures specifically designed to address the multitude of issues that contribute to wildfire risk. While one part of PGE's multifaceted WM program includes vegetation management in high risk fire zones (i.e., AWRR), the WM program is broader than just vegetation management.

Q. What is climbable vegetation and how does it contribute to wildfire risk?

A. Staff is referring to "readily climbable vegetation," which is defined in OAR 860-024-0016. In essence, readily climbable vegetation is any piece of vegetation with low limbs accessible from the ground and a growth pattern that would allow a child or average person to climb dangerously close to an energized electric line without a ladder.[12] Staff says that "[c]limbable tree violations can pose a substantial safety risk to children in the area."[13] We fully agree climbable vegetation must be promptly corrected for safety reasons. PGE works hard through its VM program to timely remove all readily climbable vegetation. However, climbable vegetation does not directly contribute to wildfire risk. Said differently, some climbable vegetation may be included in the AWRR program because it happens to exist within a high

[12] *See* OAR 860-024-0016(1)(a).
[13] Staff/600, Dlouhy/30.

risk fire zone, but not all climbable vegetation falls within high risk fire zones. Again, Staff's proposal conflates the goals and purposes of different programs and would thus create an incentive mismatch.

Q. Beyond Staff's PBRM proposal in this docket, are there other initiatives in the State of Oregon addressing wildfire mitigation that would serve to ensure that PGE is addressing wildfire risk appropriately?

A. Yes. For example, OPUC Docket Nos. AR 638 and AR 648, and the recently enacted Senate Bill (SB) 762 all focus on ensuring that appropriate regulatory mechanisms are in place to protect Oregonians from wildfire risk.

The Commission opened Docket No. AR 638 on August 25, 2020, to address risk-based wildfire protection plans and planned activities consistent with Executive Order 20-04, issued by Governor Brown on March 10, 2020.[14] Temporary rules for the 2021 fire season were adopted on May 28, 2021, and a second phase to establish permanent rules for future fire seasons is currently underway with a goal of putting permanent wildfire rules in place by the second quarter of 2022.

While Docket AR 638 was in progress, the Oregon legislature passed SB 762, a wildfire bill that, among other things, established minimum requirements for utility wildfire protection plans. The bill, signed into law by Governor Brown on July 19, 2021, required that utilities file inaugural plans for the 2022 fire season no later than December 31, 2021.

As a result, the Commission commenced Docket No. AR 648 to develop interim permanent rules in response to the requirements and timing of the new law. OPUC Docket

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[14] *In re Rulemaking for Risk-based Wildfire Protection Plans and Planned Activities Consistent with Executive Order 20-04*, Docket AR 638, Initial Staff Report (Aug. 20, 2020).

No. AR 648 began on September 15, 2021, and the Commission adopted rules on November 30, 2021.

Parties are working hard to implement best-practices in wildfire mitigation. However, the recently adopted AR 648 rules are largely procedural, and the AR 638 rulemaking has not yet been finalized, in part due to the recent change in law under SB 762.

Q. Are there any other components of SB 762 that are relevant to this rate case?

A. Yes. SB 762 explicitly allows for full and timely recovery of all reasonable operating costs and prudent investments needed to implement a wildfire protection plan. Specifically, SB 762 states: "All reasonable operating costs incurred by, and prudent investments made by, a public utility to develop, implement or operate a wildfire protection plan under this section are recoverable in the rates of the public utility from all customers through a filing under ORS 757.210 to 757.220. The commission shall establish an automatic adjustment clause, as defined in ORS 757.210, or another method to allow timely recovery of the costs."[15]

Q. What does PGE propose given this language?

A. The language in SB 762 is clear. An automatic adjustment clause should be established to allow for the timely recovery of prudently incurred wildfire mitigation costs and is what PGE would propose as the appropriate treatment for these costs moving forward.

Q. In light of the language included in SB 762, what are PGE's concerns with Staff's PBRM proposal?

A. We have four primary concerns with Staff's PBRM proposal in this GRC.

First, Staff's proposal to limit the amount of prudently incurred costs PGE can recover through rates violates the plain language and spirit of SB 762. The rate recovery provisions

[15] S.B.762, Section 3, paragraph (8), 81st Or. Leg. Assembly (2021).

of SB 762 incentivize appropriate investment in risk-based wildfire protection and mitigation plans to protect Oregonians. Consistent with SB 762, any proposal for addressing wildfire mitigation costs should allow for full recovery through rates of all reasonable operating costs and prudent investments made by a public utility to develop, implement or operate a wildfire protection plan. Staff's proposal fails to meet this standard.

Second, in addition to allowing a utility to recover certain wildfire mitigation costs in rates, Section 3 of SB 762 also requires the Commission to "establish an automatic adjustment clause as defined in ORS 757.210, or another method to allow timely recovery of the costs." Again, Staff's proposal fails to meet this standard, and in fact drastically complicates the timing for recovery of wildfire mitigation costs.

Third, even if Staff's proposal were consistent with Oregon law, which it is not, Staff's proposal is flawed and should be rejected because it misaligns metrics with consequences. Staff proposes to use the metric of *vegetation management* violations to determine the amount of *wildfire mitigation* funds PGE can recover. As discussed previously, wildfire mitigation is multi-faceted and goes beyond vegetation management. In fact, only a narrow portion of vegetation management budget is specific to wildfire mitigation (i.e., AWRR). Vegetation management focuses on proactive tree trimming and preventative management against ice, snow, or windstorm-related outages. PGE's wildfire mitigation performance cannot be appropriately gauged by its vegetation management performance because there is no inherent link between the two. This misalignment of incentives would undermine PGE's concerted efforts to mitigate wildfire risk in high risk fire zones. PGE's wildfire mitigation program funding should not be threatened by possible vegetation management violations that have nothing to do with wildfire risks (e.g., a probable violation in the middle of an urban area).

Fourth, Staff's proposal introduces a great deal of unnecessary complexity and uncertainty into an area that is already complex and evolving. The Commission's wildfire mitigation rulemakings are ongoing, and its rulemaking proceedings are not expected to be finalized until the second quarter of 2022. As those rulemakings progress, PGE continues to incorporate the best available science and data-driven methodologies into our wildfire mitigation practices, which may need to evolve even further in response to the Commission's final wildfire mitigation rules. In short, Staff's complex and flawed PBRM would undermine these efforts.

In a time of climate change and accelerating risk of destructive wildfires, the Commission should focus on developing and implementing rules and utility programs to drive best practices in wildfire mitigation rather than distracting from those efforts with an unprecedented, flawed rate mechanism that is inconsistent with Oregon law.

Q. How do you respond to this?

A. We strongly disagree with this approach. First, for the reasons described above, the PBRM is inappropriate for a number of reasons and would undermine the goals underlying wildfire management policies. Second, the use of the proposed PBRM would violate the SB 762 directive to allow for timely recovery of costs. Finally, now is not the time to pilot a new approach to recovering funds for PGE's critical WM program, particularly one that is only penalty-based. Governor Brown's Executive Order 20-04 urged "rapid actions and investments by Oregon's utility sector to reduce GHG emissions and improve the resilience [sic] of the energy system in the face of climate change and wildfire risk can reduce risks for utility customers."[16] Delaying, and possibly limiting, the recovery of prudent investments, as

[16] Executive Order 20-04 (March 2020) available at: https://www.oregon.gov/bcd/Documents/eo-energy-20-04.pdf.

Staff's PBRM proposal does, would be antithetical to Governor Brown's directive and violates SB 762.

PGE has demonstrated the prudence of its investments in both wildfire mitigation and vegetation management, and Staff has affirmed as much. As Staff witness Curtis Dlouhy stated in Opening Testimony: "I find no issues with any part of the Company's overall proposed WMVM capital or O&M expenses."[17] This is not a time to withhold funds that have been shown to be prudent.

Q. Given the concerns you have articulated above, how do you respond to Staff's proposal?

A. We strongly oppose Staff's deferral, PBRM proposal, and lack of an AAC. This rate proceeding is where PGE is expected to demonstrate prudence of its wildfire mitigation and vegetation management investments for inclusion in rates. We have demonstrated their prudence, and thus entitlement to full recovery of wildfire mitigation and vegetation management costs. Additionally, Staff's proposal is asymmetrical in that PGE would only be penalized, not incentivized, to fully invest in wildfire mitigation.

Implementation of a straightforward cost recovery mechanism and AAC is not only required by law but will also provide a straightforward regulatory pathway that allows PGE to remain nimble and respond to changes in best practices, identification of high risk fire zones, new rules, and new laws as they develop. Wildfire mitigation is an evolving science and the Commission's regulations evolve with it.

Q. Please discuss your concern about Staff's failure to propose an automatic adjustment clause (AAC) in this proceeding.

[17] Staff/600, Dlouhy/18.

A. SB 762 directs the Commission to establish an AAC to allow timely recovery of wildfire costs. However, Staff did not propose an AAC in its Opening Testimony.

Q. What do you propose in response?

A. As mentioned above, we recommend the Commission adopt an AAC in this rate case in order to comply with SB 762. Exhibit 2200/Macfarlane-Tang discusses our proposed AAC mechanism.

Q. If, despite the points described above, the Commission adopts the implementation of a deferral account and PBRM, what modifications would you propose?

A. While we disagree that a deferral account and PBRM is the appropriate approach to incentivize prudent investments in wildfire mitigation, at a minimum the performance-based metrics that impact recovery of wildfire mitigation costs need to be directly related to wildfire mitigation actions. Thus, we would propose that any performance metric should be (1) applied only to the recovery of AWRR funds and (2) based only on the number of vegetation management violations associated with increased wildfire risk in high risk fire zones. This links the funding (vegetation management program to reduce the risk of wildfire associated with vegetation near utility assets) with the metric (vegetation violations in high risk fire zones). Moreover, the Commission should ensure that any probable violations identified by Staff are appropriately validated as actual violations before any penalties would apply.

Q. If the alignment of incentives were improved, do you believe a modified PBRM would align with SB 762?

A. No.

Q. Please summarize your position on Staff's proposed deferral account and PBRM.

A. PGE strongly opposes Staff's proposed deferral account and PBRM because it (1) misaligns the metric (vegetation-based) with the consequence (funding for wildfire mitigation); (2) fails to provide for recovery through rates of all reasonable operating costs and prudent investments as required by SB 762; (3) detracts from the critical and evolving work of identifying and implementing best practices to mitigate wildfire risk; and (4) is asymmetrical in that PGE would only be penalized, not incentivized, to fully invest in wildfire mitigation. If the Commission adopts the implementation of a deferral account and PBRM in any event, it should ensure that only PGE's AWRR program is subject to the deferral account and that the metric is narrowly limited to the number of vegetation management violations in high risk fire zones. Moreover, the Commission should ensure that any probable violations identified by Staff are appropriately validated as actual violations before any penalties would apply.

Finally, we urge the Commission to adopt an AAC to provide for timely recovery of costs as required by SB 762. PGE Exhibit 2200/Macfarlane-Tang discusses our proposed AAC mechanism.

III. Prudence of Investments in ADMS Capital

Q. Please summarize Staff's Opening Testimony.

A. Staff recognizes the evolving dynamics that support ADMS' foundational role in managing the distribution system and "does not challenge the prudence of PGE's decision to invest in ADMS."[18] Staff categorized PGE's capital investment in ADMS as (1) capital investment in ADMS software, and (2) capital investment in ADMS *other* than software.[19]

Because this project was not in service as of the initial filing, Staff recommends that any ADMS capital investments not used and useful by the rate effective date as demonstrated through an officer attestation should be removed from rates.

Staff does not challenge the prudence of PGE's process to select the ADMS provider, nor the prudence of the amount of money invested in ADMS software.[20]

Staff does not believe it has sufficient information to determine the prudence of PGE's investment in the other capital investments in ADMS.[21] As a result, Staff proposes to disallow **[Begin Confidential]** [redacted] **[End Confidential]**.[22]

Q. Please respond to Staff's concern about the in-service date.

A. PGE agrees to submit an officer attestation that the project is in-service as of the rate effective date of May 9, 2022.

Q. Staff stated it received insufficient information to determine the prudence of PGE's capital investments in the "non-software" portion of ADMS, and thus propose to disallow those costs. How do you respond?

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[18] Staff/800, Sayen/4.
[19] Staff/800, Sayen/4, emphasis in original.
[20] Staff/800, Sayen/6.
[21] Staff/800, Sayen/9.
[22] Staff/800, Sayen/9.

A. The acquisition of the ADMS software itself is only one piece of the services and infrastructure necessary to implement ADMS. Additional investments in ADMS, as described in detail below, are necessary to deploy the ADMS software.

ADMS consists of complex and highly integrated systems. These systems facilitate operator visibility and control to support safe and efficient operation of utility distribution systems. As such, deployment of ADMS systems requires significant effort and cost above and beyond the cost of the ADMS software. There are four primary categories of costs in addition to the ADMS software: (1) hardware and networking equipment; (2) integrations; (3) testing; and (4) training and organization change management. These investments are necessary to prudently deploy the ADMS software and achieve the benefits of ADMS.

Q. Generally, what are the benefits of ADMS?

A. ADMS is an operational technology system that will allow PGE to manage increasing demand, integrate renewable resources, and optimize the integration of flexible loads, distributed energy resources, microgrids, electric vehicles, etc. It is a platform that will lead to a higher degree of visibility to the grid as a platform that supports the prediction, monitoring, control, optimization, and safe operation of the distribution network. This is a needed foundational system for the future of the integrated grid which will benefit customers by improving reliability and reducing outage times as we move to decarbonize our energy supply.

Q. Please describe the hardware and networking equipment necessary to support ADMS.

A. ADMS requires substantial hardware to support operational functionality across multiple applications within ADMS. ADMS implementation includes multiple environments including three development environments, quality assurance environments, production environments, and an operational training simulator environment. The quality assurance and production environments include both primary and back up instances at both the Integrated Operations Center (IOC) and Back-up Control Center (BCC). The redundant nature of the production systems and quality assurance systems is to allow for fail over from the primary systems to the backup systems to ensure continuity of service for ADMS as a critical operational technology system. These types of investments are critical for ensuring reliability and are elements of prudent management of the system.

Q. Please describe the integrations necessary to support the ADMS.

A. ADMS implementation includes integration with the following systems: Customer Information System (CIS), Load Profiles, Weather, Automated Vehicle Location (AVL), Outage Management System (OMS), Geographic Information System (GIS), PI Data Historian, Enbala, GenOnSys, Energy Management System (EMS), and Data Acquisition Node (DAN) as well as connection to field devices. These interfaces are illustrated in the ADMS Conceptual Architecture Diagram included as Confidential Exhibit 2001.

Q. Please describe the testing necessary to support the ADMS.

A. The complexity of the ADMS functions and integrations required a significant testing effort to validate operation and performance of the various components across multiple test cycles, including Functional Acceptance Testing (FAT), System Acceptance Testing (SAT), User Acceptance Testing (UAT), and Performance Testing, which is standard for operation technology implementations.

Q. Finally, please describe the training and organization change management necessary to support ADMS.

A. As part of the ADMS project, PGE separated the T&D Dispatcher role into two separate roles: Distribution System Operator (DSO) and Transmission System Operator (TSO). ADMS is a key system for monitoring and controlling the PGE distribution system. As such, extensive training was required for key users including Distribution System Operators, Grid Operations Distribution Engineers, Regional Distribution Operations Engineers, and Outage Coordinators. Additionally, training was developed and delivered to other groups impacted by the ADMS. Confidential Exhibit 2002 provides an overview of the training strategy that was executed as part of the ADMS project, including detail around training schedule for delivery to and evaluation of users prior to go-live.

Q. You stated that services other than the ADMS software were necessary to prudently implement ADMS. Please discuss each outside contract PGE executed with vendors, including the vendor, amount of investment, and services rendered.

A. To support the ADMS implementation effort, we contracted with a dozen vendors. For each vendor we describe below the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.

Q. For the vendor [Begin Confidential] [redacted] [End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential]**, the vendor provided the following:

- **ADMS System Integrator Services and ADMS Phase 1 Go-Live and Post Release Support:** These services include project management services, which maintain schedules, coordinate resources, and manage administrative responsibilities; workflow development which works with PGE internal stakeholders to develop the "to be" business processes that define future operation practices; integration which provides design work; and operations architect services which managed the development and rollout of ADMS interfaces with other systems (both from the ADMS side and the other system side) including coordination of design, development, testing and roll-out with business and IT departments and system vendors, and supporting go-live.

- **Distribution Grid Technologies System Analysis Consulting Services & ADMS/ Grid Technology System Analysis Consulting Services:** These services provided staff augmentation for the PGE Grid Technologies team in support of ADMS implementation and configuration.
- **ADMS SAT Testing Support:** This service provided additional resources to support and execute FAT and SAT, including logging of issues and validation of issue resolution.
- **Grid Operations Distribution Engineering (GODE) Support:** This service included staff augmentation to PGE's GODE group to test and tune the Distribution Power Flow (DPF) model. The DPF provides modeling of system conditions (power flow) on portions of the system where little to no telemetry exists. This was part of a joint and complementary effort with OSI.

Q. For the vendor [Begin Confidential] [redacted] **[End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.**

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential]**, the vendor provided the following:

- **Owner's Engineer / ADMS Architecture and Use Cases:** Key responsibilities included providing ADMS proposal review and vendor due diligence assessment; supporting development and articulation of use cases; serving as an independent assessor for PGE, with the primary role of identifying potential risks; providing updates to ADMS executive sponsors and other executives as needed; providing technical support and reviews; advising program management on progress of the project; ensuring project meets technical specifications and business needs; and identifying overall risks to the project.

Q. For the vendor [Begin Confidential] [redacted] **[End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.**

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential],** the vendor provided the following:

- **Training Material Creation and Training Management and Support:** Key responsibilities included development of detailed process documentation, training programs, and training materials; and providing training to selected ADMS users (DSOs and others) regarding the operation and use of the ADMS system.
- **ADMS SAT Testing Support:** Key responsibilities included the execution of assigned FAT and SAT, including logging of defects and validation of vendor resolution of defects.

Q. For the vendor [Begin Confidential] [redacted] [End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential]**, the vendor provided the following:

- **Software Development:** Developed the interface between the existing Outage Management System (OMS), which is an **[Begin Confidential]** [redacted] **[End Confidential]** product , and the new ADMS system.

Q. For the vendor [Begin Confidential] [redacted] [End Confidential] , please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential]**, the vendor provided the following:

- **Software and Licenses:** OSI provided the Monarch suite of software programs that constitute ADMS.
- **Engineering and Implementation:** Key responsibilities included supporting the design, development, installation, testing, validation, and cutover activities, and serving as subject matter experts on ADMS technology.
- **Project Engineer:** Provided direct support to PGE personnel during all aspects of the project, including hardware installation and configuration, software installation and configuration, database model management, and testing support.

- **Distribution Power Flow Support:** Provided staff augmentation to test and tune the DPF model. This was part of a joint, complementary effort with **[Begin Confidential]** [redacted] **[End Confidential]**.

Q. For the vendor [Begin Confidential] [redacted] **[End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.**

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential]**, the vendor provided the following:

- **Engineering Services and Staff Augmentation:** Given the complexities of implementing ADMS, the vendor was used to support and augment certain one-time activities such as display development, Conservation Voltage Reduction studies, software installation, and testing and verification of software against small test systems.

Q. For the vendor [Begin Confidential] [redacted] **[End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.**

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential],** the vendor provided the following:

- **Digitization of Substation Data:** Created a digital (GIS) model of substations with sufficient features and accuracy to allow PGE to import into ADMS and connect to associated feeders to complete the electrical model in ADMS.

Q. For the vendor [Begin Confidential] [redacted] [End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential]**, the vendor provided the following:

- **Software Updates to Improve the GIS Model:** ADMS requires an accurate GIS model in order to operate correctly. The vendor identified potential improvements to GIS data to facilitate the import of data to ADMS. This was part of a joint, complementary effort with **[Begin Confidential]** [redacted] **[End Confidential]**.

Q. For the vendor [Begin Confidential] [redacted] [End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential]**, the vendor provided the following:

- **Data Update:** ADMS requires an accurate GIS model in order to operate correctly; UDS identified potential improvements to GIS data to facilitate the import of data to ADMS. This was part of a joint, complementary effort with **[Begin Confidential]** [redacted] **[End Confidential]**.

Q. For the vendor [Begin Confidential] [redacted] [End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential]**, the vendor provided the following:

- **Multi Family Water Heater (MFWH) Program Interface and Testing:** Developed and deployed interface from MFWH demand response program to ADMS.

Q. For the vendor [Begin Confidential] [redacted] [End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential]**, the vendor provided the following:

- **Load Profile & Interfaces for Enterprise Services:** For the interfaces that use Amazon Web Services (AWS) platform, the vendor designed, developed, and tested the AWS side of these interfaces.

Q. For the vendor [Begin Confidential] [redacted] [End Confidential], please summarize the services rendered, their importance to implementing ADMS, and the approximate amount of funds invested.

A. For approximately **[Begin Confidential]** [redacted] **[End Confidential]**, the vendor provided the following:

- **Developed Testing Strategy:** Suggested best practices for testing a system such as an ADMS to define potential bounds for testing and associated processes.

Q. Labor costs are a component of PGE's capital investment in ADMS. What services did PGE receive from its investment in ADMS labor costs?

A. Personnel with various sources of expertise, including grid technologies, distribution system operations, GODE, energy infrastructure technology, and grid engineering and compliance, played critical roles throughout the design, development, and implementation of the ADMS system. As both the subject matter experts and resources that will operate and maintain the ADMS systems, their involvement was critical during the requirements gathering, planning, design, build, testing, and implementation of the ADMS system.

Q. What other costs were invested in the ADMS project?

A. Approximately **[Begin Confidential]** [redacted] **[End Confidential]** was spent on hardware, servers, workstations, memory, cables, power supplies, and other components, and operating system software licenses.

Q. Please summarize your response to Staff's suggestion that PGE's investment in ADMS may not be prudent.

A. The effort and investments described above were necessary to the successful implementation of ADMS and were provided at reasonable costs given the complexity and importance of the ADMS project. All ADMS capital costs are prudent and should be included in the rate base for full recovery.

IV. PRUDENCE OF CERTAIN TRANSMISSION AND DISTRIBUTION CAPITAL INVESTMENTS

Q. Please summarize Staff's Opening Testimony regarding certain transmission and distribution (T&D) capital projects.

A. Staff identifies three main concerns in their Opening Testimony. First, Staff is concerned that certain projects were not in-service as of the rate case filing. Second, Staff expressed concern about its ability to interpret the project justification forms (PJF) provided by PGE via discovery, and in particular Staff's inability to identify an initial budget against which to evaluate the final project cost. Third, Staff identified a number of projects they felt had ambiguous or vague PJFs. For some of these projects, Staff recommended certain disallowances, and for others, Staff simply said they are still reviewing the project and reserve the right to provide additional adjustments.[23]

Q. Please describe the conditions under which PGE has invested in its T&D portfolio since the last GRC in 2018, which set rates effective January 1, 2019.

A. PGE and our customers experienced numerous challenging and changing conditions in the three years since the prior GRC. We have seen increased customer growth, both as a result of increased customer usage and increased number of customer accounts. These changes require us to ensure our T&D system is planned and built to reliably serve our customers. Part of this load growth is attributed to large customer growth due to Oregon being an attractive location for new and existing businesses. Part of the load growth has been the result of the electrification of vehicles and residential and commercial buildings. Our commitment to

[23] *See*, Staff/700 and Staff/800.

decarbonization and Oregon's aggressive decarbonization policies require us to invest in a flexible and responsive T&D system, such as implementing ADMS as discussed in Section III.

At a time when we are experiencing a 30-year high in inflationary pressures,[24] our customer base has grown by 2.9 percent since our last rate case, and our sales of electricity have grown by 6.5 percent. These developments require PGE to invest in our T&D system to meet the needs of our customers.

We have also experienced unprecedented natural disasters, such as the 2020 Labor Day fire and windstorm and the February 2021 snow and ice storm, which caused widespread destruction across our system. Both the growth of our system and the storms have required us to purchase more T&D equipment more often and much of this equipment has a long lead time to acquire even in the best of times.

Exacerbating this situation has been the impact of the COVID-19 pandemic on worldwide supply chains and equipment manufacturing, coupled with increasing inflationary pressures. PGE strives to maintain the lowest inventory levels necessary while providing the highest level of restoration and customer service. The pandemic has interrupted the continued supply of many of our construction materials, including transformers.

Our transformer usage has steadily increased, due both to increased customer demand and restoration demands due to more frequent storms. For example, in the last twelve months, we had four storms that consumed record numbers of transformers. Transformer manufacturer pricing increased upwards of 15% in 2021 as raw material prices increase. Due to increased manufacturing lead times and slipping delivery dates due to supply chain

[24] *See* PGE Exhibit 1600, Ajello-Batzler/10-11.

disruptions caused by the pandemic, PGE has been forced to spot-purchase a significant number of transformers to restore power during large storms and protect our customers at a much higher cost. To help mitigate extreme shortages in both manufacturing and market supply, PGE has increased transformer inventory in the near-term. We expect transformer inventory levels to return to pre-2021 levels by the end of the second quarter of 2022.

Q. Please define the acronyms that are used in this section.

A. Below are the commonly used acronyms used in this section:

- AWO = Accounting Work Order
- BSG = Business Sponsor Group
- CRG = Capital Review Group
- IFC = Issued for Construction
- LEA = Line Extension Allowance
- MLA = Minimum Load Agreement
- PJF = Project Justification Form

Q. Please respond to Staff's first concern about certain projects not being in-service as of the rate case filing.

A. Staff expressed concern that a number of projects would not be in-service at the time the rates go into effect on May 9, 2022. The following projects that were not in-service as of the rate case filing are now in-service.

Project	**In-Service Date**
P36693 - Helvetia Substation Project	September 10, 2021
P36907 - Reconductor Murrayhill-St Marys	The majority of the project (representing **[Begin Confidential]** [redacted] **[End Confidential]** is in-service as of November 8, 2021. The remaining AWO (representing approximately **[Begin Confidential]** [redacted] **[End Confidential]**) is expected to be placed in-service by the end of 2021.
P37110 - Restore Bethel-RB 230 kV Line	July 5, 2021
P37114 - Project BaT	October 26, 2021

For the remaining projects, we will provide an officer attestation that the project is in-service as of the rate effective date of May 9, 2022. Ms. Hanhan and Mr. Sayen proposed inconsistent dates by which PGE should show the project as being in-service. Ms. Hanhan proposed that "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"[25] while Mr. Sayen proposed that any project not "used and useful by April 30, 2022, as demonstrated through an officer attestation, should be removed from rates effective May 1, 2022."[26] PGE agrees to provide an officer attestation that the following projects are in service as of the rate effective date of May 9, 2022, or otherwise remove the project's costs from rate base:

- P36341 - St Marys Battery Addition
- P36762 - Milliken Tower Reinforcement_SE PDX
- P36680 - Brookwood Substation Conversion
- P36868 - Shute Capacity Addition
- P36417 - Replace/Rewind Failed Transformers
- P36867 - Remote Disconnect Project

[25] Staff/700, Hanhan/6.
[26] Staff/800, Sayen/18.

Q. What general issues did Staff raise regarding cost controls and budgeting?

A. Staff claimed that, as a general matter, PGE's filing demonstrated a lack of focus on cost control.[27] Staff raised concerns regarding PGE's budgeting process and the challenges of understanding the components, including PJFs and change orders.[28] Staff invited PGE to clarify its cost control process and protocols in reply testimony.[29]

Q. Has PGE clarified its cost controls and budgeting process?

A. Yes. PGE has provided additional detail on its cost management and capital budgeting process in PGE/1800. In that testimony, PGE provides a detailed explanation of its cost management and budgeting processes and explains why many of Staff's assertions about PGE's cost control process are simply incorrect. PGE also explains why PJFs, rather than change orders, are the better source of information regarding project costs.

Q. How do you respond to Staff's assertion that the project cost information provided to Staff was "not intuitive"?[30]

A. We understand that each company's cost-control processes and internal language are different and that information about those processes may not be intuitive to third parties reviewing those processes. PGE is confident in its cost-control processes and is interested in ensuring Staff understands it, as well. PGE has explained its cost-control and budgeting processes to Staff in discovery, over the phone, through virtual meetings, and is providing additional detail in PGE Exhibit 1800.[31] To the extent Staff has any further questions after reviewing PGE's

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[27] Staff/100, Muldoon/5-8.
[28] Staff/700, Hanhan/5, 8-14.
[29] *See, e.g.,* Staff/700, Hanhan/14; Staff/800, Sayen/19-20.
[30] *See, e.g.,* Staff/800, Sayen/22.
[31] PGE would note that Staff's uncertainty about PGE's cost-control processes does not provide an evidentiary foundation for disallowing prudently incurred project costs.

testimony, PGE would be happy to schedule an additional meeting to ensure Staff fully understands PGE's processes and forms.

Q. Did PGE follow the processes detailed in PGE Exhibit 1800 with respect to each of the transmission and distribution projects singled out by Staff for scrutiny or proposed disallowances?

A. Yes. PGE followed its standard cost-control and budgeting process for each of the transmission and distribution projects singled out by Staff for scrutiny or proposed disallowances.

Q. Please respond to Staff's concern that PJFs were ambiguous or hard to interpret.

A. Staff proposes disallowances or raises concerns with a number of projects based primarily on Staff's assertion that PGE's PJFs were ambiguous or hard to interpret. First, PGE disagrees with Staff's assertion that the PJFs fail to provide Staff with the information needed to review PGE's project budgets. Please see PGE Exhibit 1800 for detail on PGE's PJFs and change orders. Second, as PGE notes in Exhibit 1800, PGE has provided PJFs to Staff in at least the last three rate cases going back six years without similar complaints.[32] While the format of the PJFs has recently changed and may have caused some initial confusion, PGE's new PJF format includes more information across more fields than the older format.

Q. Staff states that it is unsure whether it has received all information provided in PJFs, stating that is unsure it has received complete PJFs for each project.[33] Can you respond?

A. In response to discovery, PGE inadvertently sent Staff PJFs that omitted some details and others for which the PJF was inadvertently cut off, due to system limitations. When PGE became aware of this issue, it corrected the issue. To PGE's knowledge, Staff has full and

[32] PGE/1800, Bekkedahl, Ewers/26.
[33] Staff/700, Hanhan/8-9.

complete PJFs for each project Staff reviewed. PGE is also happy to provide additional clarifications or detail to assist Staff's review.

Q. Do you have any other initial observations about the basis for Staff's proposed disallowances?

A. Yes. First, for most of the projects for which Staff proposes a disallowance, Staff fails to identify specific adjustments based on project documentation it received from PGE. Instead, Staff simply asserts in a conclusory fashion that some costs should be disallowed because Staff views PGE's documentation as "ambiguous." PGE disagrees with this characterization of its project documentation but would note in any event that PGE submitted timely responses to discovery and spent time discussing its processes with Staff in an effort to satisfy Staff's concerns. Furthermore, PGE was willing to continue discussions with Staff to the extent Staff had remaining concerns. Instead, Staff proposed a number of punitive disallowances based on broad assertions that PGE's responses were, in Staff's view, unclear. It is difficult, if not impossible, to respond with specificity to proposed disallowances based on conclusory assumptions that lack a specific evidentiary foundation.

Second, Staff states that it may also, in subsequent rounds of testimony, "recommend a general disallowance to address PGE's lack of oversight on capital spending and incent PGE to improve its processes," assuming Staff is not satisfied with information provided in PGE's reply testimony.[34] Again, PGE strongly disagrees with Staff's characterization of its cost control and budgeting process. Nothing in this GRC or Staff's testimony supports the conclusion that PGE lacks internal controls; to the contrary, PGE's controls are robust. But this statement also represents an inappropriate threat of proposed disallowances based on

[34] Staff/700, Hanhan/14.

conclusory assertions that lack evidentiary foundation or support. While PGE is happy to provide additional information in its reply testimony, it is difficult, if not impossible, to respond with specificity to general statements of this nature.

Q. Staff proposes disallowances or raises concerns with a number of projects based on uncertainty about where to find initial budgets against which Staff can compare final costs. Please respond.

A. PGE does not use the phrase "initial budget" or "target budget" when establishing the anticipated costs for a project. However, the best proxy for an initial project budget is the estimated "total project budget" shown on the PJF at the time of the execution funds request. As described in PGE/1800, significant rigor and standardized estimating processes go into developing the estimated "total project budget" that is provided at the time of the execution funding request. The standardized estimation parameters used to estimate the "total project budget" at the time of execution funding request is based on the IFC design estimate, which provides an accuracy range of -15% to +20%.[35]

Q. Do you have additional observations about Staff's focus on "initial budgets"?

A. Yes. Throughout its testimony on PGE's transmission and distribution capital projects, Staff generally assumes that all increases in project costs are imprudent and proposes disallowing all cost increases on that basis. Staff points to no specific basis for such recommendations other than broad assertions about the ambiguity of PGE's project documentation. As the Commission has noted, unanticipated circumstances can increase a project's cost beyond the initially anticipated contingencies.[36] Even if project costs include increases over initially

[35] *See*, Table 1 in PGE/1800, Bekkedahl-Ewers/11.
[36] *In re PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket No. UE 374, Order 20-473 at 35, 39 (Dec. 18, 2020).

anticipated contingencies, those costs are recoverable if prudently incurred.[37] Rather than pointing to evidence that budget increases were unreasonable or identifying specific instances of imprudence, Staff simply assumes that increases in a project budget represent imprudent spending. PGE addresses the reasons for budget increases and demonstrates the prudence of its spending on a project-by-project basis below.

Q. Please respond to Staff's statement that it "reserves the right" to propose additional disallowances in future rounds of testimony.

A. Throughout Ms. Hanhan's and Mr. Sayen's testimony, Staff states that it reserves the right to propose additional disallowances in future rounds of testimony. In many instances, this "reservation of rights" is premised on Staff's assertion that, while Staff has found no evidence of mismanagement or cost overruns, Staff finds PGE's project documentation to be vague or ambiguous and would later like another bite of the apple. In other instances, Staff seems to be complaining that it simply has not received sufficient information to conduct its review.

Neither rationale supports a general "reservation of rights" to propose additional disallowances in future rounds of testimony. First, PGE has responded to discovery in a timely fashion and is unaware of any outstanding Staff requests that would be necessary for Staff's comprehensive review. There is no reason Staff cannot make concrete recommendations based on the information they have. Second, we understand that the purpose of establishing several rounds of testimony in a rate case is to allow the parties to join issue on disputed elements of PGE's rate case and to narrow the issues as the case moves forward. This requires parties to conduct discovery and review materials in a timely fashion and to identify and communicate issues in a timely manner. A blanket "reservation of rights" undermines this

[37] *Id.* at 35.

purpose. Finally, Staff's "reservation of rights" is prejudicial to PGE. The regulatory process is designed to provide notice and allow parties enough time and opportunity to investigate and respond to issues. It would be procedurally inappropriate and prejudicial to PGE for Staff to provide additional adjustments to PGE's rate case projects in subsequent testimony.

PGE has provided extensive information on the investments included in its rate case in initial testimony and in the discovery process. Exhibit 2003 summarizes the information provided by PGE in discovery on each of the projects singled out by Staff. The amount of discovery provided by PGE has been substantial and has provided parties with sufficient information to review prior to developing arguments for inclusion in Opening Testimony.

Notwithstanding the foregoing, below we provide clarity and additional information to demonstrate the prudence of PGE's investments in the specific projects identified by Staff and AWEC.

A. Topic: Minimum Load Agreements

Q. Staff expressed concerns about the Butler substation and the Helvetia substation projects based in part on misunderstandings about Minimum Load Agreements. Please summarize comments about Minimum Load Agreements that were made in Staff's Opening Testimony.

A. Staff discussed Minimum Load Agreements (MLAs) in the context of the Butler substation and the Helvetia substation projects. Staff raised several concerns with how MLAs function, how projects with an MLA are financed, and whether including these projects in the rate case will benefit all ratepayers.[38] We address each of these below.

[38] Staff/700, Hanhan/25.

Q. Please describe the process when a customer notifies PGE it intends to increase its demand.

A. When a customer expects to increase its electrical demand or start new service, it notifies PGE. PGE then determines whether the existing infrastructure is sufficient to meet the expected increase in demand. Various departments within PGE work together: key customer management, transmission and distribution planning, distribution operations engineering, corporate finance, legal, and pricing to determine if upgrades are needed to serve the load and any estimated cost to do so.

Q. If PGE determines infrastructure upgrades are needed, what happens?

A. If infrastructure upgrades are needed to meet a large customer's expected future demand, there can be risk to PGE in making a large capital investment if that increased demand does not materialize. There are three primary mechanisms by which PGE can mitigate the risk of cost shifts to other customers when capital investments are necessary to respond to expected increases in large customer demand:

(1) For upgrades other than substations, PGE can provide a line extension allowance (LEA) consistent with the amounts in Schedule 300 of PGE's Tariff multiplied by the expected load; the customer pays any amount in excess of the LEA as described in Rule I of PGE's Tariff.

(2) An alternative to LEA is the negotiation and execution of an MLA. More information about MLAs and how they work is provided below.

(3) The third option is to require the customer to provide an up-front payment for the entire cost of the line extension or entire project if substation work is involved as defined by PGE's Tariff with a refund after five years based on an LEA calculation

using actual customer load data to receive a full or partial refund. This third option is not used often and only for customers that cannot demonstrate good credit.

Q. What is an MLA?

A. An MLA is a contract with a customer, whereby the customer commits to paying the greater of actual demand or an escalating minimum monthly demand amount, as expressly laid out in the MLA, for a stated number of years (at least five years).

In general, each MLA: 1) specifies minimum demand levels for purposes of calculating the demand charges during each specified period; 2) provides an option to pay off the MLA early should the customer want to cancel the contract before expiration; and 3) provides for the recovery of all the costs stated in the MLA should the customer fail to commence service or disconnects service prior to the expiration of the MLA contract. Under circumstances described in 3) above, if PGE determines it can utilize newly installed assets for the purpose of serving other customers, PGE may do so and will consider mitigating the customer's cost responsibility.

Q. How does an MLA protect other PGE customers?

A. An MLA is designed to obtain a legally enforceable commitment from the large, new load or growing load customer to pay a *minimum amount* of revenues every year, to PGE, for the term of the MLA, which is at least five years. The MLA states the "minimum monthly demand" for each year of the MLA. The customer is contractually obligated to pay all demand-related charges billed at the *greater of* the measured peak demand based on actual meter readings, or the minimum monthly demand stated in the MLA. This enables PGE to recover revenues from the customer that are based on, at a minimum, the amount of expected demand that led to the investment in the project; this protects other customers.

The minimum monthly demands increase per the MLA schedule, reflecting the minimum expected ramp rate of the customer's load growth. This bridges the gap between the infrastructure upgrades being in place to support increased load growth with the time it takes for a customer to ramp operations and demand. It is expected that the customer's load is permanent at the end of the MLA and the customer will continue to pay PGE for services received, well beyond the term of the MLA.

For the duration of the MLA, the terms and conditions of the MLA are drafted to protect PGE's other customers against the risk of the large customer prematurely terminating the agreement and discontinuing distribution service from PGE by requiring the customer to reimburse PGE for any and all unrecovered costs incurred in connection with the project up to the time of the occurrence of the triggering event (i.e., request to terminate the MLA, or request to discontinue distribution service), capped at some amount (generally commensurate with the project's expected costs).

Q. What happens when the MLA ends?

A. Each MLA is offered for at least a five-year term, and only to customers who demonstrate creditworthiness. This allows PGE to make the capital investments needed to serve the customer's expected new or growing load, while allowing the customer to ramp its load over several years as its operations expand. At the end of the MLA, it is expected that the customer's load will have increased by at least the minimum load amount stated in the last year of the MLA. Once it has ramped up, this load is expected to continue into the future, perhaps even growing more. Even though the MLA has run its course for the designated term and is no longer in effect, the customer continues to receive services from, and pay revenues to, PGE.

Q. Is there risk of a stranded asset if PGE builds a substation designed to serve a customer's expected load growth, but the customer decreases or ends operations after the MLA ends?

A. Technically, yes. There is always a stranded asset risk whenever PGE invests in capital upgrades to meet customers expected future needs, whether it is due to one single large customer or, for example, a group of residential customers. PGE has planning processes in place to forecast expected needs and determine what capital investments are necessary to ensure safe and reliable operations.

In the case of the Butler and Helvetia substations built in the Hillsboro area, we believe the risk of stranded assets is extremely low. First, the two customers with the major load growth driving the need for these capital investments are both existing PGE customers with good creditworthiness. Second, there is ongoing load growth in that area of PGE's service territory generally, and the substations would be used to support that load growth, should one or both of those large customers unexpectedly and significantly decrease demand.

Q. **Are the Butler and Helvetia substations "dedicated" to each respective large customer?**

A. No. PGE does not "dedicate" any substation to serve an individual customer. PGE owns the substations and the land upon which the substations are located. In the case of Butler and Helvetia, **[Begin Confidential]** [redacted]

[redacted] **[End Confidential].**

Q. Staff expressed confusion over how the costs of the Butler and Helvetia substations would be recovered through retail rates, given that there are MLAs in place for each project. Please explain.

A. Staff is confusing these two issues. The MLAs serve a specific function, as described above. **[Begin Confidential]** [redacted] **[End Confidential]**.

The costs of these substations are recovered through retail rates, which are set based on the unbundled revenue requirements, and then allocated based on our marginal cost studies. Assigning the costs of the substations to PGE's retail customer base is consistent with Commission policy.[39] Under long-standing Commission policy, costs incurred for construction of facilities needed to provide safe, reliable retail load service are justified by PGE's obligation to serve retail customers. With the exception of specific customer-assigned costs defined in PGE's tariff, these costs are spread across PGE's customer base in a nondiscriminatory manner, consistent with PGE's Commission-approved retail rates. This is true whether the upgrade at issue is on PGE's transmission system or its distribution system.

B. <u>Topic: P36708 - Butler Substation Project</u>

[39] Staff has invited PGE to explain how these projects "benefit all ratepayers." This is not the standard applicable to projects built to accommodate growing customer load. While the projects at issue provide benefits to multiple customers in the area where they are sited, this fact, along with MLAs, simply serves to mitigate risk to other customers should the future load fail to materialize.

Q. Please summarize Staff's Opening Testimony on P36708 - Butler Substation Project.

A. First, Staff discussed the electrical need justifying construction of the project, noting that PGE has said that the project: 1) is due to a single customer's planned increase in demand; and 2) that it provides transmission system flexibility and increases reliability for all customers in the area served by the substation.[40] Staff also stated that PGE "was unable to produce white papers on the need for the Butler substation because this project was 'expedited.'"[41]

Second, **[Begin Confidential]** [redacted] **[End Confidential]**.[42]

Third, Staff stated that while it "could not immediately identify any clear evidence of overruns or mismanagement that would be an unfair burden to customers," the PJF "did not contain much information to help Staff verify prudent management of costs." Staff also noted it was "unclear how timing played a role in costs" given that this was an expedited project. Staff concluded with saying it is "still reviewing the project and waiting on additional discovery not received in time for this testimony" and "reserves the right to provide additional adjustments."[43]

Q. How do you respond to Staff's statement that PGE was unable to produce a whitepaper on the need for this substation?

A. Whitepapers are required for reliability-driven projects. This project was driven by customer need. Nonetheless, the whitepapers for the Hillsboro Reliability Project and the Horizon VWR3 Project discuss the load forecasts associated with the new Butler substation.[44]

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[40] Staff/700, Hanhan/18.
[41] Staff/700, Hanhan/18.
[42] Staff/700, Hanhan/18.
[43] Staff/700, Hanhan/19-20, lines 14-2.
[44] *See*, PGE's revised response to OPUC Data Request No. 334, submitted on August 25, 2021 provided in Confidential Exhibit 2005 and Highly Confidential Exhibit 2006.

Q. What is the electrical need of Butler Substation and how has this been documented?

A. PGE's response to OPUC Data Request No. 574, submitted on September 8, 2021, explained the electrical need for this project, **[Begin Confidential]** [redacted] **[End Confidential]** to provide reliable load service to other customers.[45]

[Begin Confidential] [redacted] **[End Confidential]**. PGE's analysis showed that the existing infrastructure was insufficient to serve the increased demand in addition to existing load service requirements. The project includes a reconductor of the St Marys-Sunset 115 kV line, which will be used to serve other customers. Other upgrades will provide reliability benefits from the transmission system facilities (115 kV substation equipment, control enclosure, and 115 kV lines into the substation).[46]

Q. Staff stated that the substation is [Begin Confidential] [redacted] **[End Confidential]**[47] **Is this correct?**

A. No. As we stated in our response to OPUC Data Request No. 574, dated September 8, 2021, PGE **[Begin Confidential]** [redacted] **[End Confidential]** upon which the substation was built.[48] As we elaborated in our response to OPUC Data Request No. 663, submitted on September 27, 2021, **[Begin Confidential]** [redacted]

[45] *See*, Confidential Exhibit 2005.
[46] *See,* PGE's response to OPUC Data Request No. 574 provided in Confidential Exhibit 2005.
[47] Staff/700, Hanhan/18.
[48] *See,* Confidential Exhibit 2005.
[49] *See*, Confidential Exhibit 2005.

[redacted] **[End Confidential]**.

Q. Staff states that the MLA requires the customer to [Begin Confidential] [redacted] **[End Confidential][50] Is this correct?**

A. No. Please see our explanation in the MLA section above.

Q. Staff expressed concern about potential cost increases due to this project being "expedited." How do you respond?

A. Staff's concerns are unfounded, and Staff has presented no evidence that would substantiate this concern. This project was appropriately designed and scoped, and it was completed within the estimated total project budget and sooner than planned. This was due to prudent project and cost management. While PGE prefers to bid a project out to contractors when the engineering design is complete, in this situation, PGE bid the project out to contractors at 30% design and then worked with the contractor to adjust the price for any changes in design. This approach takes more work for PGE to finalize costs with the winning bidder, but it allows PGE to engage in construction planning and material acquisition much earlier. That said, there is no reason to assume that this planning alternative drives costs increases, and there were none here. Due to the expedited approach to the project, PGE had to very closely manage all permits and major material orders to avoid delays in the project. However, the expedited treatment did not increase costs: the project was completed within the estimated total project budget and sooner than planned.

Q. Staff asked PGE to "justify the Butler substation load in its Reply Testimony and explain how it will benefit all ratepayers."[51] Please respond.

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[50] Staff/700, Hanhan/18.
[51] Staff/700, Hanhan/19.

A. This substation is necessary to serve customer load. As discussed in the MLA section above, under long-standing Commission policy, costs incurred for construction of facilities needed to provide safe, reliable retail load service are justified by PGE's obligation to serve retail customers and, under Oregon law, are spread across PGE's customer base in a nondiscriminatory manner.

Q. Please respond to Staff's statement that it "is still reviewing the project and waiting on additional discovery not received in time for this testimony" and "reserves the right to provide additional adjustments."[52]

A. It is unclear what "additional discovery" Staff is referencing. As shown in PGE Exhibit 2003, we responded to all OPUC data requests within fourteen days. Our first response was filed on July 23 and our last response was filed on October 6, which was two and a half weeks prior to Staff's Opening Testimony filing. PGE submitted twenty-one responses to OPUC data requests within this time, including provision of the PJF, the executed MLA, change orders, and documentation supporting the change orders. We also chose to provide additional information on this project in our response to OPUC Data Request No. 889, even though that data request did not ask for information for this project. That information was provided on October 13.

Staff had adequate time to analyze this project and the prudence of PGE's investment, and to include recommendations in Staff's Opening Testimony. It would be procedurally inappropriate and prejudicial to PGE for Staff to provide additional adjustments to this project in subsequent testimony.

[52] Staff/700, Hanhan/19-20.

Q. What was the estimated total project budget for this project and what was the final incurred cost of the project?

A. The first request for partial execution funding occurred in December 2019. At the time, the estimated total project budget was **[Begin Confidential]** [redacted] **[End Confidential]**.[53] The final incurred cost of this project was **[Begin Confidential]** [redacted] **[End Confidential]**.[54] This project was on budget and ahead of schedule.

Q. Please summarize how PGE demonstrated the prudence of this project.

A. This project was energized ahead of schedule and on budget. As a customer-driven project, a whitepaper was not required to be developed, but two other whitepapers have documented the load growth in the Hillsboro area. We have explained that the **[Begin Confidential]** [redacted] **[End Confidential]** mitigating cost impacts on other customers. We have explained that assigning the costs of the substation to PGE's retail customer base is consistent with Commission policy, while also noting that the addition of the customer's load growth will help offset the costs of the upgrade. Finally, we provided all discovery on a timely basis; it would be procedurally inappropriate and prejudicial to PGE for Staff to provide additional adjustments to this project in subsequent testimony.

C. <u>Topic: P36693 - Helvetia Substation Project</u>

Q. Please summarize Staff's Opening Testimony on P36693 - Helvetia Substation Project.

A. Staff observed that there was no whitepaper on this project because it was an "expedited" project primarily triggered by **[Begin Confidential]** [redacted] **[End**

[53] *See,* "Description & Scope – Justification 4" of Confidential Exhibit 2007.
[54] *See,* "Revision Summary" of Confidential Exhibit 2007.

Confidential][55] However, Staff also said it "does not have an issue with the need for this project based on industrial growth in the Hillsboro area."[56] Staff was unclear **[Begin Confidential]** [redacted] **[End Confidential]**[57] Relatedly, Staff invited PGE to "clarify the circumstances surrounding the financing of this project and explain how including it in the rate case will benefit all ratepayers" in Reply Testimony.[58] Finally, Staff asserted that the PJF "did not contain much information to help Staff verify prudent management of costs" and that "it is unclear how timing played a role in costs" given it is an expedited project.[59] Staff again asserted it is "still reviewing the project and reserves the right to provide additional adjustments."[60]

Q. How do you respond to Staff's observation that the Company does not have a whitepaper on this substation?

A. As noted above, whitepapers are required for reliability-driven projects, whereas this project was driven by customer need. Our revised response to OPUC Data Request No. 334, submitted on August 25, 2021, provided whitepapers for the Hillsboro Reliability Project and the Horizon VWR3 Project; both of which discuss the load forecasts associated with the new Helvetia substation.[61]

Q. Staff stated that it was [Begin Confidential] [redacted] **[End Confidential]** [62] **How do you respond?**

[55] Staff/700, Hanhan/24-25.
[56] Staff/700, Hanhan/24.
[57] Staff/700, Hanhan/25.
[58] Staff/700, Hanhan/25.
[59] Staff/700, Hanhan/26.
[60] Staff/700, Hanhan/26.
[61] *See*, Confidential Exhibit 2005 and Highly Confidential Exhibit 2006.
[62] Staff/700, Hanhan/25.

A. Again, Staff seems to misunderstand the purpose of the MLA and how PGE recovers costs from customers. Please see our explanation in the MLA section above.

Q. Staff asks for clarity "surrounding the financing of this project and [to] explain how including it in the rate case will benefit all ratepayers."[63] How do you respond?

A. This substation is necessary to serve customer load. As discussed in the MLA section above, under long-standing Commission policy, costs incurred for construction of facilities needed to provide safe, reliable retail load service are justified by PGE's obligation to serve retail customers and, under Oregon law, are spread across PGE's customer base in a nondiscriminatory manner.

Q. What was the estimated total project budget and what was the final incurred cost of the project?

A. The estimated total project budget, at the time of the first execution funding request in June 2020, was **[Begin Confidential]** [redacted] **[End Confidential]**.[64] This was based on 75% accuracy and included the construction and commissioning of the substation, distribution feeders, and the associated line work to provide service to the customer. Engineering was at 90% with the IFC package for the substation construction expected by the end of June 2020. Once the IFC package was received, the request for proposals for construction work were issued. At the time, three vendors had provided estimates based on the 90% design package to help inform the execution funding request.[65] The final incurred cost was **[Begin Confidential]** [redacted] **[End Confidential].**[66] This project was completed under budget.

[63] Staff/700, Hanhan/25.
[64] *See*, "Description & Scope – Justification 8" in Confidential Exhibit 2007.
[65] See, "Description & Scope – Justification 8" in Confidential Exhibit 2007.
[66] *See*, "Revision Summary" in Confidential Exhibit 2007.

Q. Please summarize how PGE demonstrated the prudence of PGE's investment in this project.

A. This project was executed on time and under budget. The final incurred cost of this project was $19.5 million, below the estimated total project budget of $20.9 million. We have discussed how the MLA functions and how costs are recovered by assigning the costs of the substations to PGE's retail customer base, consistent with Commission policy.

D. Topic: Hillsboro Load Forecasts

Q. AWEC takes issue with PGE's Hillsboro Load Forecasts. Please summarize AWEC's Opening Testimony on Hillsboro load forecasts and planning documents.

A. AWEC asserts that there is a "mismatch between the planned load used to justify PGE's T&D buildout and the forecast load used to set rates" and alleges that PGE "appears to be building capacity ahead of need and failing to secure sufficient customer contributions and minimum load agreements to support this early and excessive buildout."[67]

Q. Are AWEC's assertions correct?

A. No.

Q. Please describe how PGE uses load forecasts when planning the T&D system and when developing rates in a GRC.

A. PGE plans its T&D system to reliably and safely provide power to customers. PGE is responsible for investing prudently in our system by looking years into the future and ensuring the system is available when the forecasted customer load growth occurs. This is also necessary to ensure compliance with NERC standards on the transmission system. The acquisition and purchase of certain equipment requires long lead times; for example, it can

[67] AWEC/200, Kaufman/12.

take over a year to receive a transformer. By its very nature, investing in our T&D system is "lumpy" and cannot perfectly match load growth.

In contrast, the load forecasts used in a GRC are for a test year. In this GRC, the future test year is 2022. The load forecast used for setting rates is a snapshot-in-time (2022), meaning it includes only 2022 forecasted load associated with the large customers, despite the existence of MLAs extending beyond 2022. This does not mean the load forecasts used in the GRC are inaccurate, nor does it mean that the load forecasts used for planning the T&D system are inaccurate.

Q. Please describe the timing difference between capital investments and load growth.

A. It is simply the structure of how the GRC functions to include capital investments that are in service as of the rate effective date of the GRC, and to allocate the unbundled revenue requirements by using the load forecast of the GRC test year. There will always be a timing mismatch when capital upgrades associated with MLAs are included in the unbundled revenue requirement and rates are set based on the test year forecast. PGE cannot include the load forecasts from, say, Year 5 of the MLAs, if the GRC test year is not Year 5. For example, **[Begin Confidential]** [redacted] **[End Confidential]**. The UE 394 GRC uses a 2022 test year. If the GRC were to use, say 2026 as the future test year, then that amount of load, at a minimum, would be captured. However, that is not how rates are set.

Even though a customer's load ramps up over time, T&D investments cannot ramp as smoothly as load can. If a substation is needed by the end of the ramp period, PGE cannot just build a partial substation for Year 1 and slowly expand it as the load grows. If PGE expects a certain amount of load to show up within a few years, it is prudent and efficient to build based on expected need instead of having to redesign and reconfigure the expansion over time. Remember that the MLA provides only the *minimum* load amount. A customer may ramp more quickly than the MLA requires, meaning the infrastructure needs to be there for the customer to do so. A customer can only increase its load if the infrastructure is there.

Q. AWEC asserts that [Begin Confidential] [redacted] **[End Confidential]** [68] **How do you respond?**

A. AWEC appears to be referencing the planning forecast that was included in the 2018 Hillsboro Reliability whitepaper. This whitepaper evaluated the existing transmission in the Hillsboro area given that there were operational constraints during peak loading conditions. The 2018 studies for NERC TPL-001-4 compliance substantiated these loading concerns. As stated in the Executive Summary of the whitepaper, by 2021, load projections indicated that the loss of one of the Horizon bulk power transformers would result in an overload of the remaining Horizon bulk power transformer during peak summer conditions. In addition to these existing constrained conditions, hundreds of megawatts of new load were projected over the next ten years in the Hillsboro area. Those load projections, used for T&D planning purposes, were shown in Table 1 of the whitepaper, which is the table referenced by AWEC. The combination of the existing constraints and the expected load growth led T&D Planning to recommend construction of the Hillsboro Reliability Project. The forecasts used for T&D planning will not perfectly match the point-in-time test year forecast used in a GRC.

[68] AWEC/200, Kaufman/17.

To be clear, the infrastructure project associated with the large customer (LC44) referenced by AWEC is not included in this GRC. We have an MLA in place with that customer, but the project will not be in-service by the rate effective date of this rate case.

Q. AWEC states that the MLAs that "PGE secured should have provisions to recover the incremental cost of the Hillsboro Reliability if the load did materialize [sic]."[69] How do you respond?

A. We assume AWEC meant "if the load did *not* materialize." As described previously, an MLA enables PGE to recover revenues from the customer that are based on, at a minimum, the amount of expected demand that led to the investment in the project, which protects other customers.

Q. AWEC asserts that the Shute substation was constructed "at least two years earlier than necessary."[70] How do your respond?

A. AWEC mischaracterizes the Shute Substation Capacity Addition Project Whitepaper. AWEC states that, according to the whitepaper, "the Shute capacity expansion is not necessary until 2023."[71] In fact, the whitepaper says that the current system "*may* be adequate until at least 2023" and goes on to say, "[h]owever, this poses the risk of not being able to serve customer load in a timely manner, hindering customer operations until new facilities can be constructed. Engineering time is roughly a year and construction time is an additional year and a half. Delaying the start of the process could have cascading timeline consequences in the future."[72]

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[69] AWEC/200, Kaufman/18.
[70] AWEC/200, Kaufman/20-21.
[71] AWEC/200, Kaufman/20.
[72] *See*, Shute Substation Capacity Addition Project Whitepaper, January 24, 2020, page 6, emphasis added (hereinafter, "Shute Whitepaper") provided in Confidential Exhibit 2005.

The Shute whitepaper listed six large customers that have projects underway or have inquired about adding projects in the area. Most of the customers require N-1 redundancy. When the whitepaper was written in January 2020, 40% of the redundant capacity at Shute was already being used. T&D planning recommended implementing Option 1 by 2022 to avoid depleting all the available redundant capacity at Shute substation. It would also minimize the impacts to sensitive customers and provide longer term capacity availability. The customers in the area of Shute substation typically have very aggressive construction and load ramp schedules, so adding capacity in advance would allow PGE to respond quickly to these customers.[73]

Q. AWEC asserts that "PGE has executed the Hillsboro Reliability Project ahead of need."[74] How do you respond?

A. AWEC is wrong. The Hillsboro Reliability Project whitepaper was developed at the end of 2018 and we are just executing on part of it now. There are four substations included in the Hillsboro Reliability Project: Brookwood, Orenco, Main, and the future Evergreen substation.[75] The only substation we are requesting rate recovery for in this case is Brookwood. The T&D portfolio is regularly evaluated to determine when system upgrades should be implemented. Projects require many years to design, permit, and construct.

Q. Please summarize your response to AWEC's assertions that the Hillsboro load forecast is not consistent with planning documents.

A. First, T&D planning documents look five to ten years into the future as it can take years to design, construct, and energize T&D upgrades. Second, T&D upgrades are "lumpy" given

[73] Shute Whitepaper, page 8.
[74] AWEC/200, Kaufman/21, line 3.
[75] *See*, Hillsboro Reliability Project whitepaper, pages 10-17, provided in Confidential Exhibit 2005.

that the components (e.g., transformers) only come in certain sizes and because it can be more cost-efficient to design and build a project based on the expected future need instead of only near-term need. Third, the GRC uses the load forecasts of a future test year, meaning only the forecasted load of 2022 is included in this rate filing. In conclusion, PGE has prudently invested in its T&D system based on the information shown in the planning studies and PGE has forecasted load for the future test year (2022) based on best available information. A mismatch in these numbers does not mean they are inaccurate. More information on load forecasts is available in PGE Exhibit 2100/Riter.

E. Topic: P36763 - Install Horizon VWR3 Transformer

Q. Please summarize Staff's Opening Testimony on Project P36763 - Install Horizon VWR3 Transformer.

A. First, Staff affirmed that the "project seems to be supported by load forecasts that support the transmission expansion."[76] Second, Staff stated it "could not identify any clear evidence for overruns or mismanagement" of project costs but asserted that the PJF for the project was "particularly ambiguous and vague."[77] Third, Staff observed that PGE's direct case showed the project cost of $13.3 million, while PGE's response to OPUC Data Request No. 311 showed a lower cost of $9.1 million.[78] Given that discrepancy, Staff proposed disallowance of $4.2 million, representing the difference between what was provided in PGE Exhibit 801 and in PGE's response to OPUC Data Request No. 311.[79]

[76] Staff/700, Hanhan/31.
[77] Staff/700, Hanhan/32.
[78] Staff/700, Hanhan/32.
[79] Staff/700, Hanhan/32.

Q. What is the basis for the difference in project cost shown in PGE Exhibit 801 versus PGE's response to OPUC Data Request No. 311?

A. PGE incorrectly reflected the project cost in Exhibit 801. PGE corrected the typographical error via our response to OPUC Data Request No. 582 which was submitted on September 8, 2021.[80] We clarified that "[w]hile the description of P36763 in the testimony is correct, the cost was $9.1 million rather than the $13.3 million presented in the testimony."[81]

Q. How do you respond to Staff's proposal to disallow $4.2 million?

A. Staff's recommended disallowance is based on an error that has since been corrected. With the correction of that error, the basis for Staff's proposed disallowance no longer exists. To clarify, the typographical error was only in our written narrative in Exhibit 801. The correct value was used to calculate the revenue requirement, which was the source of the information provided in OPUC Data Request No. 311.

Q. What was the estimated total project budget and what was the final incurred cost of the project?

A. The estimated total project budget, at the time of the first execution funding request in August 2020, was $9.0 million.[82] This was based on 90% estimates being completed for the Horizon substation and transmission scopes of work. PGE moved the Rock Creek-Evergreen line work order to another project (P36666 - Build Evergreen Substation) to better align schedules. The funds for the Rock Creek-Evergreen line were never requested or incurred on this project.[83] Due to the change in scope, the estimated total project budget for P36763 - Install Horizon

[80] *See*, PGE's response to OPUC Data Request No. 582 provided in Confidential Exhibit 2005.
[81] *See*, PGE's response to OPUC Data Request No. 582 provided in Confidential Exhibit 2005.
[82] *See*, "Description & Scope – Justification 6" in Confidential Exhibit 2007.
[83] *See*, "Description & Scope – Justification 6" in Confidential Exhibit 2007.

VWR3 Transformer was decreased by $2.0 million, resulting in an adjusted estimated total project budget of $7.0 million ($9.0 million - $2.0 million).

The final incurred cost of this project was $6.1 million,[84] which is below the adjusted estimated total project budget of $7.0 million. The project came in under budget.

Q. Based on the information provided above, what is your response to OPUC Staff's concerns about cost management of this project and recommended adjustment?

A. PGE has fully documented the prudence of its investments in this project, as summarized above. OPUC Staff did not have concerns with the construction of the project, finding it "supported by load forecasts that support the transmission expansion."[85] Staff's proposed disallowance was based on a typographical error in our direct case that we corrected via our response to OPUC Data Request No. 582.[86] Despite Staff's position that the PJF was "particularly ambiguous and vague," Staff did not "identify any clear evidence for overruns or mismanagement that would be an unfair burden to customers."[87] The final incurred cost of $6.1 million is below the adjusted estimated total project budget of $7.0 million. Thus, there is no foundation upon which to disallow our investment in this project, which is prudent and should be included in rate base for cost recovery.

F. Topic: P36039 – Harborton Reliability Project Phase 1

Q. Please summarize Staff's Opening Testimony on Project P36039 - Harborton Reliability Project Phase 1.

[84] *See*, "Revision Summary" in Confidential Exhibit 2007.
[85] Staff/700, Hanhan/34.
[86] *See*, PGE's response to OPUC Data Request No. 582 provided in Confidential Exhibit 2005.
[87] Staff/700, Hanhan/32.

A. Staff raised concerns about budget increases shown in the PJF that were "not well explained" and recommended the Commission disallow "all the costs identified" which total **[Begin Confidential]** [redacted] **[End Confidential]** Staff invited PGE to clarify these ambiguities in Reply Testimony.[88]

Q. What was the estimated total project budget, and what was the final incurred cost of the project?

A. The estimated total project budget, at the time of the execution funding request in May 2018, was $36.1 million. This was based on a 90% design estimate. The final incurred cost of the project was $35.0 million, meaning this project was completed under budget.

Q. Please discuss the origin and basis of Staff's first proposed disallowance of [Begin Confidential] [redacted] **[End Confidential].**

A. It appears that Staff is referring to the 2019 Capital Call that occurred in May 2018, when there was an increase of **[Begin Confidential]** [redacted] **[End Confidential]** in the project's budgeted 2019 capital.[89]

Q. Please discuss the origin and basis of Staff's second proposed disallowance of [Begin Confidential] [redacted] **[End Confidential].**

A. It appears that Staff is referring again to the 2019 Capital Call that occurred in May 2018, but this time to the increase of **[Begin Confidential]** [redacted]

Q. [redacted]

[88] Staff/700, Hanhan/22.
[89] *See,* "Description & Scope – Justification 7" in Confidential Exhibit 2007.
[90] *See,* "Description & Scope – Justification 7" in Confidential Exhibit 2007.

A. [redacted] **[End Confidential]**.

Q. Having demonstrated that the first proposed disallowance is already included in the second proposed disallowance, please discuss the second proposed disallowance of [Begin Confidential] [redacted] [End Confidential].

A. The estimated total project budget for this project was $36.1 million, as shown at the time of the execution funding request in May 2018. Because the total project budget was established at the time of the execution funding request in May 2018, the increase of **[Begin Confidential]** [redacted] **[End Confidential]** in May 2018 does not indicate an increase to the project's estimated total project budget. Rather, this represents an update to the planning phase budget to include updated cost estimates based on the actual execution of contractor and vendor contracts. Prior to May 2018, the project was in the "planning phase," meaning cost estimates had a wider range of accuracy based on the estimation parameters discussed in Exhibit 1800.

The May 2018 budget update included the cost of the executed contract with the contractor to construct the Harborton 23kV-115kV substation. The executed contract was for **[Begin Confidential]** [redacted]

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[91] *See,* "Description & Scope – Justification 7" in Confidential Exhibit 2007.

[redacted] **[End Confidential]** construction contract combined with decreases in other areas where other executed contracts came in less than our internal estimates. For example, the bid for seismic improvements was **[Begin Confidential]** [redacted] **[End Confidential]** than our internal estimate, which was conservative because of the known soil liquification issues due to proximity of the substation construction site to the Willamette River. In addition, the actual cost of materials was 22% less than the earlier planning estimate.

In summary, the net increase of **[Begin Confidential]** [redacted] **[End Confidential]** was the combined effect of updating internal cost estimates with actual contractor bids, which enabled us to request execution funds and establish the estimated total project budget of $36.1 million in May 2018.

Q. Please discuss the origin and basis of the [Begin Confidential] [redacted] **[End Confidential][92] Staff recommends disallowing.**

A. It appears that Staff is referring to Revision 113, which was presented at the June 2019 BSG / 2020 Capital Call. Proposed Revision 113 requested **[Begin Confidential]** [redacted] **[End Confidential]** in 2020 capital to complete the 115 kV route.[93]

This request was <u>rejected</u> during the BSG workflow process. Therefore, it is not included in the **[Begin Confidential]** [redacted] **[End Confidential]** we have included in our initial filing for recovery. There is no "Revision 113" shown in the Revision Summary, which only shows approved requests as explained in PGE/1800.

Q. Please summarize your response to Staff's recommendation to disallow [Begin Confidential] [redacted] **[End Confidential].**

[92] Staff/700, Hanhan/21.
[93] *See*, "Description & Scope – Justification 10" in Confidential Exhibit 2007.

A. The first cost increase of **[Begin Confidential]** [redacted] **[End Confidential]** identified by Staff for disallowance is included in the second cost increase **[Begin Confidential]** [redacted] **[End Confidential]**.

The second proposed disallowance of **[Begin Confidential]** [redacted] **[End Confidential]** does not represent a "cost increase" as Staff claims. Instead, it reflects the revision of the planning-phase budget to include actual contracted costs rather than estimates. Internal estimates were both lower and higher than actual contracted costs, but were consistent with our range of accuracy parameters described in PGE/1800. The **[Begin Confidential]** [redacted] **[End Confidential]** was included in the estimated total project budget of $36.1 million provided in May 2018 when execution funds were first requested. As is consistent with PGE's cost control management and budgeting processes discussed in PGE/1800, execution funds are requested when we have a higher degree of confidence in the total project budget, which is informed by our planning work and acquisition of contractor bids.

The third and final cost increase of **[Begin Confidential]** [redacted] **[End Confidential]** identified by Staff for disallowance was never approved by the BSG and is thus not included in the project funds included in our rate case filing.

The final incurred cost of this project, $35.0 million, was below the estimated total project budget of $36.1 million. This project came in under budget. Based on the foregoing, Staff's recommendation should be rejected.

G. <u>Topic: P36571 - Marquam Radial Feeder Addition</u>

Q. Please summarize Staff's Opening Testimony on Project P36571 - Marquam Radial Feeder Addition.

A. Staff is concerned about the difference between the "total capital" cost of **[Begin Confidential]** [redacted] **[End Confidential]** and the amount included in our initial filing of $9.5 million. Staff calculates that the difference between the total capital costs and fully loaded costs is **[Begin Confidential]** [redacted] **[End Confidential]**. Staff asserts that the difference between a project's capital costs and a project's fully loaded costs is "typically 30%," which would be **[Begin Confidential]** [redacted] **[End Confidential]** for this project. Staff proposes to disallow the difference between **[Begin Confidential]** [redacted] **[End Confidential]**, adjusted based on a loadings ratio Staff calculated from the PJF and DR 311, resulting in a total disallowance of **[Begin Confidential]** [redacted] **[End Confidential]**. [94]

Q. What was the estimated total project budget, and what was the final incurred cost of the project?

A. The estimated total project budget was **[Begin Confidential]** [redacted] **[End Confidential]**.[95] The final incurred cost was **[Begin Confidential]** [redacted] **[End Confidential].**[96] The project was completed under budget.

Q. What does "fully loaded" mean?

A. "Fully loaded" is the sum of direct costs (e.g., outside services, materials, and labor) *plus* overheads.

Q. What are overheads and how are they calculated?

A. The two main categories of overheads included in capital projects are labor loadings and construction overheads. The methodology of calculating overheads has not changed since the

[94] Staff/800, Sayen/24-25.
[95] *See*, "Description & Scope – Justification 4" in Confidential Exhibit 2007.
[96] *See*, "Revision Summary" in Confidential Exhibit 2007.

prior GRC. However, the cost components used to calculate overheads have changed. For example, PGE's health and wellness costs are forecasted to increase 5.9% annually from 2020 actuals to the 2022 test year used in this GRC, driven primarily by expected medical premium increases.[97]

Labor loadings are applied to incurred labor charged to capital projects. These loadings include employee benefits, including health and wellness costs, payroll taxes and paid time off.

Construction overheads are support costs for construction that are not directly assigned to specific construction projects. Support activities relate to the planning, designing, engineering, supervision, administration and constructing and completing of construction projects. Overheads are incurred for activities that charge to construction but are not practical or cost-effective to charge directly to the projects. As a result, the projects bear an equitable share of overheads as prescribed by FERC.

For T&D construction overheads specifically, the construction overheads are first determined by looking at a pool of costs that include activities associated with: system planning, engineering, design, system mapping, scheduling, coordination of new customer connects, dispatch crews, system control to ensure continued service during construction, safety inspections, system testing, system reliability, substation engineering, process work orders, dispatch for repair, damage claims, inspection of customers facilities for construction, and permitting. Although this is not an all-inclusive list of every work activity, it demonstrates the high volume of different types of work activities and the difficulties that would arise in trying to capture these costs by direct charging to individual work orders.

[97] *See*, PGE/300, Mersereau-Neitzke/28.

A capitalization rate is developed each month based on the amount of directly incurred capital and O&M work that has been performed on a year-to-date basis. This capitalization rate is applied to the overall charges in the pool at month end, with those charges reclassified to individual capital projects. The capitalization rate is applied to the amount of labor and outside services incurred within each project. Those charges are reclassified to capital and are included in the calculation of "fully loaded" costs that are included in our rate case filing.[98]

Q. Staff asserts that the "difference between a project's capital costs and a project's fully loaded costs is typically 30%." Given the foregoing, do you agree with this statement?

A. No. As described above, overheads are calculated specifically for each project based on the type of individual charges within each project. Each project will have its own amount of overheads.

Q. Please provide the breakdown of incurred costs, overheads, and AFUDC for this project that was included in your initial filing.

A. The table below shows the incurred costs, overheads, and AFUDC that was included in close to plant in our rate filing. The overheads for this project are 38% of the total project cost.

[Begin Confidential]

[redacted]

[End Confidential]

[98] *See*, PGE's Capital Accounting Policy, provided as Attachment A to PGE's response to OPUC Data Request No. 282, provided in Exhibit 2004.

Q. Given this, how do you respond to Staff's proposed disallowance?

A. We disagree with Staff's proposed disallowance because the methodology Staff used to determine what the amount of fully loaded costs "should be" is based on conjecture. There is no typical percentage that can be applied to a project to calculate what its fully loaded costs "should be," and PGE has provided a breakdown based on actual values that demonstrate there is no discrepancy between the total capital costs anticipated for the project and the amount being requested in this rate case. The calculation of overheads requires a specific methodology based on a project's individual characteristics. We have summarized how overheads are calculated and shown the breakdown of costs included in this project.

Thus, Staff's recommendation should be rejected. All costs of this project have been demonstrated to be prudent.

H. Topic: P36910 – Outer Division Multi Modal Project

Q. Please summarize Staff's Opening Testimony on Project P36910 – Outer Division Multi Project.

A. Staff states that the difference between the "total capital cost" of **[Begin Confidential]** [redacted] **[End Confidential]** shown in the PJF and the amount being requested in the rate case of $6.2 million is about **[Begin Confidential]** [redacted] **[End Confidential]**. Staff stated it "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]** Staff recommends disallowing the delta of **[Begin Confidential]** [redacted] **[End Confidential]** in direct costs.[99]

[99] Staff/800, Sayen/26.

Q. What was the estimated total project cost and what was the final incurred cost for this project?

A. The estimated total project budget was **[Begin Confidential]** [redacted] **[End Confidential]**.[100] The final incurred cost was **[Begin Confidential]** [redacted]. **[End Confidential]** [101] This project was completed under budget.

Q. Please respond.

A. As described in our response to P36571 - Marquam Radial Feeder Addition, overheads are calculated specifically for each project based on the type of individual charges within each project. Each project will have its own amount of overhead.

Q. Please provide the breakdown of incurred costs, overheads, and AFUDC for this project that was included in your initial filing.

A. The table below shows the incurred costs, overheads, and AFUDC that was included in close to plant in our rate filing. The overhead for this project is 32% of the total project cost.

[Begin Confidential]

[redacted]

[End Confidential]

Q. Given this, how do you respond to Staff's proposed disallowance?

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[100] *See*, "Description & Scope – Justification 3" in Confidential Exhibit 2007. Due to the structure of this project, partial execution funds were requested in via separate stage-gates. The estimated total project budget was $3.5-$4.5 million when the initial partial execution funding request was made for the first third of the poles that needed to be replaced; the estimated total project budget range decreased to $3.5-$4 million by the time the final execution request was made for the remaining poles.

[101] *See*, "Revision Summary" in Confidential Exhibit 2007.

A. We disagree with Staff's proposed disallowance because the methodology Staff used to determine what the amount of fully loaded costs "should be" is incorrect. The calculation of overheads requires a specific methodology based on a project's individual characteristics. We have summarized how overhead is calculated and shown the breakdown of costs included in this project. Staff has pointed to no evidence to demonstrate that any costs associated with this project are imprudent. Staff's recommendation should be rejected.

I. Topic: P36861 – Division Transit Project

Q. Please summarize Staff's Opening Testimony on Project P36861 – Division Transit Project.

A. Staff recommends disallowance of what it characterizes as an apparent discrepancy of **[Begin Confidential]** [redacted] **[End Confidential]** in direct costs found between the "total project capital cost" of **[Begin Confidential]** [redacted] **[End Confidential]** reported in the PJF in June 2021, compared to the sum of "Outside Services" of **[Begin Confidential]** [redacted] **[End Confidential]** and "Materials" of **[Begin Confidential]** [redacted] **[End Confidential]** shown in PGE's response to OPUC Data Request No. 326.

Q. What was the estimated total project budget, and what was the final incurred cost of the project?

A. The estimated total project budget was $12-$14 million.[102] The final incurred cost was $10.3 million.[103] The project was completed under budget.

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[102] *See*, "Description & Scope – Justification 2" in Confidential Exhibit 2007. Due to the structure of this project, partial execution funds were requested in via separate stage-gates. The estimated total project budget was $12-$14 million when the initial partial execution funding request was made for the first set of the poles that needed to be replaced; the estimated total project budget range decreased to $10-$12 million by the time the final execution request was made for the remaining poles.
[103] *See*, "Revision Summary" in Confidential Exhibit 2007.

Q. Please explain the [Begin Confidential] [redacted] **[End Confidential] discrepancy identified by Staff.**

A. The primary discrepancy is due to the application of the **[Begin Confidential]** [redacted] **[End Confidential]** credit of Contributions in Aid of Construction (CIAC). The PJF shows only incurred costs; the CIAC is a credit that is applied to the fully loaded cost of the project, which is what is included in our rate case filing and is shown in Attachment A in PGE's response to OPUC Data Request No. 326. The remaining differences are due to comparing different vintages of data. The referenced PJF was updated in June 2021, while the value included in our initial filing and shown in Attachment 326-A was based on actuals through March 2021 and forecasts through April 2022.

Q: Did Staff recognize that CIAC might be at issue?

A. Yes. Staff noted that CIAC might account for some of the perceived discrepancy.[104]

Q. What was Staff's response to the CIAC issue?

A. Staff proposed disallowing 100 percent of the asserted discrepancy despite Staff's recognition that CIAC was likely a legitimate reason for some of the perceived variance.[105]

Q. Please summarize your response to Staff's recommended disallowance.

A. Of the **[Begin Confidential]** [redacted] **[End Confidential]** discrepancy noted by Staff, **[Begin Confidential]** [redacted] **[End Confidential]** of that is attributed to the application of the CIAC credit, as noted by Staff. The remaining difference is due to the comparison of two different vintages of data Staff's recommendation should be rejected. All costs of this project have been demonstrated to be prudent.

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[104] Staff/800, Sayen/23.
[105] Staff/800, Sayen/23.

J. Topic: P36373 - Blue Lake Phase II Project

Q. Please summarize Staff's Opening Testimony on P36373 - Blue Lake Phase II Project.

A. Staff stated that the project "seems to be supported by load forecasts that support the transmission expansion."[106] Staff asserts that 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."[107] Staff asserts that cost increases appear to be caused by "removal of contaminated soils, soil excavation that was not originally budgeted for, and landscaping requirements."[108] The total cost increase found under revision 127 of the PJF totaled **[Begin Confidential]** [redacted] **[End Confidential]**." [109] Thus, Staff recommends the Commission "disallow all the cost increases identified, which amount to **[Begin Confidential]** [redacted] **[End Confidential]**. Based on the loadings ratio Staff calculated from the PJF and DR 311, this amounts to a total disallowance of **[Begin Confidential]** [redacted] **[End Confidential]**."[110]

Q. Please discuss the cost increases in Revision 127 of the PJF.

A. It appears that Staff incorrectly interpreted the change made in Revision 127 of the PJF.[111] As stated, the total project budget increased by **[Begin Confidential]** [redacted] **[End Confidential]**. This **[Begin Confidential]** [redacted] **[End Confidential]** represents the summation of the **[Begin Confidential]** [redacted] **[End Confidential]** increase to 2020 funds and the **[Begin Confidential]** [redacted] **[End Confidential]** increase to 2021 funds. Staff appears to have mistakenly summed all three increases, totaling **[Begin Confidential]**

[106] Staff/700, Hanhan/23.
[107] Staff/700, Hanhan/23.
[108] Staff/700, Hanhan/23.
[109] Staff/700, Hanhan/23.
[110] Staff/700, Hanhan/24.
[111] *See*, "Description & Scope – Justification 14" in Confidential Exhibit 2007.

[redacted] **[End Confidential]**, which is double the actual increase as stated in the PJF (accounting for rounding).

The **[Begin Confidential]** [redacted] **[End Confidential]** in 2020 increase was due to additional labor, equipment rentals, and disposal fees to dispose of contaminated concrete that was found during the environmental remediation of the Linneman substation. The excavation revealed the contaminated concrete which was unexpected. PGE prudently managed the costs necessary to address the situation that could not have been known in advance.

The **[Begin Confidential]** [redacted] **[End Confidential]** in 2021 increase was due to changes needed for final restoration under City permits. Final restoration conditions, such as landscaping requirements, sidewalks, and ADA ramps, are not included in the permits and require ongoing negotiation with the City. Because the negotiations were ongoing, PGE did not know how much final restoration conditions would cost at the time it set the project budget.

Q. Please summarize your response to Staff's recommendation to disallow [Begin Confidential] [redacted] **[End Confidential].**

A. First, Staff incorrectly interpreted the budget adjustment made via Revision 127. The total budget change was **[Begin Confidential]** [redacted] **[End Confidential]**, the summation of an increase of **[Begin Confidential]** [redacted] **[End Confidential]** for 2020 increase and an increase of **[Begin Confidential]** [redacted] **[End Confidential]** for 2021. Thus, Staff's adjustment should be **[Begin Confidential]** [redacted] **[End Confidential]**, at most. However, the cost increases should not be disallowed because the additional costs were due to the unanticipated need to remove and dispose of contaminated concrete, and changes to final restoration requirements that were subject to ongoing negotiation with the City. These changes were difficult to foresee, and PGE prudently managed the costs once discovered.

Based on the foregoing, Staff's recommendation should be rejected. All costs of this project have been demonstrated to be prudent.

K. Topic: P36270 - Roseway Substation Project

Q. Please summarize Staff's Opening Testimony on Project P36270 - Roseway Substation Project.

A. First, Staff acknowledged that the project "seems to be supported by load forecasts that support the transmission expansion."[112] Second, Staff asserted that "[d]ue to the ambiguity of the PJFs, Staff cannot verify prudent management of costs" and therefore recommended that the Commission "disallow all the cost increases identified, which amounts to **[Begin Confidential]** [redacted] **[End Confidential]** in direct costs."[113] Staff adjusted this to a total disallowance of **[Begin Confidential]** [redacted] **[End Confidential]** after applying the loadings ratio Staff calculated from the PJF and PGE's response to OPUC Data Request No. 311.[114] Staff asked PGE to "clarify these ambiguities" in Reply Testimony.[115]

Q. Please discuss Staff's first recommended disallowance of [Begin Confidential] [redacted] [End Confidential]

A. Staff asserts that the **[Begin Confidential]** [redacted] **[End Confidential]**."[116] Staff is correct that **[Begin Confidential]** [redacted] **[End Confidential].**

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[112] Staff/700, Hanhan/28.
[113] Staff/700, Hanhan/29.
[114] Staff/700, Hanhan/29.
[115] Staff/700, Hanhan/29.
[116] Staff/700, Hanhan/28.

However, an explanation *was* provided in the text box, though unfortunately there was a typographical error in the explanation such that it referenced **[Begin Confidential]** [redacted] .**[End Confidential]**[119]

Q. Please discuss Staff's second recommended disallowance of [Begin Confidential] [redacted] **[End Confidential]**

A. The **[Begin Confidential]** [redacted] **[End Confidential]**[120] was primarily due to Washington County's plans to widen a major intersection on Tualatin Valley Highway. As a result, the county did not allow PGE to use our previously intended route for communications on which our earlier project budgets had been based. PGE typically consults with the county early in the design process after developing the initial estimate. Here, after developing the initial estimate, PGE had to change the route of the fiber communication line to include an additional 1.5 miles, two additional railroad crossings, the replacement of nine distribution poles, and a new underground section. Because of these changes, the transmission and distribution cable bids and other project costs (fiber installation and railroad permits) increased. The scope change was not known until December 2019, PGE's redesign was

[117] *See*, "Description & Scope – Justification 8" in Confidential Exhibit 2007.
[118] *See*, "Description & Scope – Justification 8" in Confidential Exhibit 2007.
[119] *See*, "Description & Scope – Justification 8" in Confidential Exhibit 2007.
[120] *See*, "Description & Scope – Justification 9" in Confidential Exhibit 2007.

completed in early February 2020, and the cost estimates were received in late February. This was an issue outside of our control, but once it was known, we prudently managed the increased costs.

Q. Please discuss Staff's final recommended disallowance of [Begin Confidential] [redacted] [End Confidential].

A. There were three primary reasons for the **[Begin Confidential]** [redacted] **[End Confidential]** funding: an increase in the cost of distribution materials over our initial estimate; repair costs for conduit that was incorrectly installed by the contractor; and additional construction requirements requested by the City of Hillsboro to restore the road crossing. The contractor error was outside of our control, and PGE invoiced the contractor for **[Begin Confidential]** [redacted] **[End Confidential]** for rework required in the field.

Q. Given the foregoing, how do you respond to Staff's recommendation to disallow the three cost increases identified by Staff, which add to [Begin Confidential] [redacted])[End Confidential]?

A. We appreciate the opportunity to provide more explanation around these cost increases. We recognize the PJF contained a typographical error such that the description of the **[Begin Confidential]** [redacted] **[End Confidential]** was difficult to locate. We also clarified that we obtained compensation from the contractor for increased costs resulting from the error in the conduit installation. As described above, these cost increases were prudently incurred and should be included in rate base.

L. <u>Topic: P35834 - Round Butte Transmission Upgrades</u>

Q. Please summarize Staff's Opening Testimony on Project P35834 - Round Butte Transmission Upgrades.

A. Staff acknowledged that "the project seems to be supported by load forecasts that support the transmission expansion."[121] Staff also identified "significant cost increases" during this project in the following amounts: **[Begin Confidential]** [redacted], [redacted].**[End Confidential]** [122] These cost increases were attributed to higher than expected rock content of the soil that increased the labor time, the limited windows in which work could be completed in order to minimize outages, and lodging and overtime costs due to the remote location of the project. Staff believes PGE could have been aware of the rock content at an earlier point and could have performed the work more cost effectively. Staff believes it would be fair and reasonable to split the difference resulting in a recommended disallowance of **[Begin Confidential]** [redacted] **[End Confidential]**[123]

Q. What were the circumstances of this project that resulted in increased labor and labor-related costs?

A. There were several factors that combined to increase labor and labor-related costs: (1) limited windows of time when plant outages could be taken in order for the crews to de-energize the lines and safely perform work; (2) the structure of the labor union contract; and (3) the remote location of the project.

Q. Why were plant outages limited?

[121] Staff/700, Hanhan/36.
[122] Staff/700, Hanhan/36-37.
[123] Staff/700, Hanhan/37-38.

A. In order to safely perform transmission work, plant outages were needed at the generation facilities connected to the line (reregulating dam, Pelton dam, and Round Butte dam). Outages were only able to occur between midnight and 4 a.m. This was due to limited storage between the reregulating dam, which must match river flows, and Pelton dam, and limitations on how much water could be spilled in order to maintain water quality (e.g., to not exceed total dissolved gas limits which can harm fish) to stay compliant with the FERC license. Thus, any work that required de-energization could only occur between midnight and 4 a.m. each day.

Given the limited windows in which work could be completed and compressed schedule, more than one crew was dispatched to work on this project, when typically, only one crew (consisting of four to five people) would have been used.

Q. What is the structure of the labor union contract?

A. The labor union contract has several provisions that impact the rate of pay of crews based on specific conditions. First, the standard workday at straight time pay is 7 a.m. to 3:30 p.m., Monday through Friday. Any work outside of these hours is paid as overtime (double the straight time pay rate). Finally, there is an additional type of pay called "golden time." The union contract requires crew members to receive 8.5 hours of rest between shifts. Any time a crew member does not receive 8.5 hours of rest between shifts, golden pay is provided. Golden pay is 8 hours of straight time pay on top of the next shift's pay. Crews are also paid at the applicable labor rate when traveling in a company vehicle.

Q. What was the impact of the remote work location?

A. The Round Butte transmission project is located in Central Oregon, near Madras. PGE crews are stationed at the Avery service center in Tualatin. Crews had to drive from Avery to Round Butte in company vehicles, meaning this drive time was compensated at the applicable labor rate. Crews also had to drive to and from lodging located approximately 45 minutes from the work site every day. As they traveled in company vehicles, this travel time was paid at the applicable labor rate. Each crew member received a per diem for three meals per day, and PGE paid for the lodging for the crews. Because the nearest lodging was not available, crews had to stay at more expensive lodging that was also further from the work site.

Q. Given these constraints, what might a typical workday look like for a crew member?

A. The time clock would begin as the crew member traveled to the work site in a company vehicle for the normal 7 a.m. to 3:30 p.m. straight-time work shift. Because certain work could only occur during plant outages, and plant outages could only occur between midnight and 4 a.m., the crew member might continue working until midnight to prepare for the work that would occur during the plant outage. The crew member would be paid overtime (twice the straight-time hourly rate) for the hours worked outside of the standard shift. The clock would stop once the crew member returned to the hotel.

Since the crew member would not receive 8.5 hours of rest prior to the next workday starting at 7 a.m., the crew member would receive golden time (straight time pay for eight hours).

This cycle would continue while the work was getting done. PGE used more than one crew to accelerate the work given the outage limitations, but there was still a substantial amount of overtime and golden time paid during this time.

Work often occurred on the weekends as well, which is always paid at the overtime rate because it is outside of the standard workday provided in the labor union contract.

Q. How were labor costs forecasted?

A. Labor costs were first forecasted at the beginning of the project, when the plant outages were expected to be less stringent. As plant outages became more limited, this compressed the amount of work that needed to occur in a limited window, resulting in higher-than-expected labor costs. For the safety of our crews, we assume provision of at least 8.5 hours of rest between each workday, meaning we do not include golden time pay in our labor cost forecasts. However, given the unique circumstances of this project, we needed to pay golden time.

Labor costs were also forecasted based on a certain scope of work. That scope of work expanded during the course of the project, resulting in increased labor costs which had not been included in the original forecast. Labor and expenses were analyzed, reviewed, and validated by the Project Controls Analyst and the Project Manager at the close of each pay period, not waiting for the month close. It was this scrutiny and analysis that informed the monthly forecast updates and the associated funding project revisions in 2019.

Submittal of Revision 138 in July 2019 was a result of analysis to date on the actual spend of labor and expenses.[124] Revision 146 submitted in September 2019 was a decrease in funding to release funds estimated in Revision 138; this was part of the ongoing analysis and review of costs.[125] Revision 156 submitted in November 2019 trued-up costs incurred for labor and expenses, which was an increase of **[Begin Confidential]** [redacted] **[End Confidential]** [126] Multiple revisions and continual review and analysis of the labor costs are demonstrative of the level of cost control on this project.

Q. Why were the issues with the rock content of the soil not known sooner and included in the budget?

[124] *See*, "Description & Scope – Justification 16" in Confidential Exhibit 2007.
[125] *See*, "Description & Scope – Justification 17" in Confidential Exhibit 2007.
[126] *See*, "Description & Scope – Justification 18" in Confidential Exhibit 2007.

A. As is typical, we developed our initial budget estimates based on preliminary scope and the information known at the time. The budget and funding evolved as more information was obtained, such as surveys and engineering. When we first started this project, geo-tech work had not yet been funded or completed. Subsurface content was determined with the geo-tech study and report. After obtaining the geo-tech report, we found that just a few inches under native soil and existing substation gravel surface began heavy rock and boulder layers for several feet. This increased all civil excavations costs compared to typical soil. It also required a different type of foundation and significantly more copper grounding materials because of the variation in resistivity of rock compared to organic material.

The rock variable was a significant hurdle. It was impossible to dig in a significant portion of the substation and the civil crews had to use jack hammers and chip the rock to create depth for installing underground facilities. Because it was a significant challenge to create depth, many of the facilities could not be installed at standard depths so they were encased in concrete for protection. This added a significant delay to the project.

Q. Did the scope of work for this project increase, thus impacting the amount of labor needed?

A. Yes. A far more detailed relaying scheme was developed as design proceeded due to interface with the Bonneville Power Administration (BPA) and communication requirements. This led to more labor for control, protection, and communications requirements both at Round Butte and remote ends of lines and communications circuits and, in some places, replacement or removal of equipment at remote ends. Also, the installation of the main equipment at Round Butte in the 500kV and 230kV areas required additional smaller equipment, structures, and foundations than originally estimated, due to the limited outage windows available.

Q. Why were these increased costs not known at the start of the project?

A. PGE had limited experience working on projects as remote as this one. This project was unique given the impact its remote location had on labor costs due to the union contract and the limited outage windows available. These impacts were not fully known at the beginning of the project and were therefore not included in the budget. Similarly, the rock content of the ground was far more challenging than initially expected, meaning the costs for additional time and materials to accommodate the subgrade heavy rock layers were not included in the initial forecast. Further, the relaying schemes described above are complicated and required close coordination and planning with other utilities at several locations.

Q. Given the foregoing, how do you respond to Staff's recommended disallowances?

A. The first proposed disallowance of **[Begin Confidential]** [redacted] **[End Confidential]**, shown in Revision 36 from October 2015, relates to items that closed prior to 2019.[127] As such this **[Begin Confidential]** [redacted] **[End Confidential]** is not included in our rate filing and this recommended disallowance is not applicable.

The causes and demonstration of prudence for the five proposed disallowances **[Begin Confidential]** [redacted] **[End Confidential]** are described above. In order to maintain healthy water quality for aquatic species and comply with the FERC license terms, PGE had to limit the outages at Pelton dam to midnight to 4 a.m. Certain work could not be performed safely without de-energization which constrained the hours in which crews could work. Based on the labor union contract, these work hours fell outside of the standard workday which resulted in overtime pay (twice straight time pay). The limited outage windows also resulted in long work hours, and crews

[127] *See*, "Description & Scope – Justification 4" in Confidential Exhibit 2007.

were not able to receive 8.5 hours of rest between shifts, resulting in golden time pay. The remote work location and lodging in Central Oregon resulted in additional labor costs as crews are paid when they travel in a company vehicle. PGE did not have the ability to change the requirements of its FERC license or its labor union contract, and PGE needed to timely complete this project because it was critical to meet NERC compliance obligations. The primary objective of the upgrades was to get a Remedial Action Scheme in place to mitigate transmission system instability that could result from outages of the lines connected to the Round Butte substation and to increase reliability and minimize the occurrence of outages.

M. Topic: P37062 - Rebuild Grizzly-RB 500kV Towers

Q. Please summarize Staff's Opening Testimony on project P37062 - Rebuild Grizzly-RB 500kV Towers.

A. Staff "agree[d] with the Company's decision to pursue the project" and "could not identify any clear evidence for overruns or mismanagement that would be an unfair burden to customers."[128] Nonetheless, Staff stated the PJF "does not include very much cost information on the project." Despite having "no adjustment recommendations," Staff said it is "still reviewing" and "reserves the right to provide additional adjustments."[129]

Q. Please discuss the circumstances and need for this project.

A. This project restored the Grizzly-Round Butte 500 kV line after a windstorm on May 30, 2020, took down a portion of the line. The project entailed the cleanup and demolition of the line that came down during the storm, the restoration of the transmission line, and the restoration of the communication circuit that was also damaged during the storm. The Grizzly-Round

[128] Staff/700, Hanhan/41.
[129] Staff/700, Hanhan/41.

Butte 500kV line is a critical line to PGE and our customers, and it was necessary to rebuild and energize the line as quickly as possible. The Grizzly-Round Butte 500kV also impacts the ratings of the California Oregon AC Intertie (COI). With this line out of service the COI is derated 1000 MW, which is a significant impact during the summer peak months.

Given the importance of re-energizing this line, PGE worked with BPA to obtain the steel towers from BPA's emergency stock and subsequently replaced them. This expedited the project by eight to twelve weeks, especially impressive during the early stages of the COVID pandemic, and highlights our collaborative partnerships with regional entities, such as BPA and the U.S. Forest Service. For example, given the emergency conditions of this project, the U.S. Forest Service expedited approval for us to work on their property.

The Grizzly-Round Butte 500kV line was built in conjunction with the Bethel-Round Butte 230kV line to integrate generation into the Central Oregon transmission system and allow PGE to directly access the California Independent System Operator (CAISO) without wheeling transmission on another provider's system. When this line was forced out of service due to the windstorm, it put PGE's system in a state where the combined loss of this line and the Redmond-Round Butte 230kV line would require PGE to reduce the total generation at Pelton/Round Butte to 200 MW. This limit protects the stability of the transmission system. Additionally, NERC compliance requirements dictate that the transmission system must be able to stay within System Operating Limits (SOLs) for the next possible outage. With the Grizzly-Round Butte 500 kV line out of service, another outage could have resulted in an overload on another line.

The measurable benefit of this project was getting this line back in service so that these issues mentioned above would be mitigated. The benefits of this project were fully realized when the transmission line was energized on August 31, 2020.[130]

Q. Please describe the prudence of PGE's investment in this project.

A. As discussed in the Post Completion Report submitted as Attachment 889-G in PGE's response to OPUC Data Request No. 889, the original project budget was $4.70 million, and the final project cost was $4.74 million.

There were two main cost drivers that impacted the final budget.

First, due to the need to retain a contractor quickly, the selected contractor provided a bid without a geo-tech survey or completed IFC package. However, soil conditions were rockier than expected, which led to changes to the contractor costs due to design changes and additional labor. Most of these changes were absorbed by the use of contingency. The net increase of the additional contractor costs was **[Begin Confidential]** [redacted] **[End Confidential]**

Second, there was a decrease of **[Begin Confidential]** [redacted] **[End Confidential]** to the original budget due to internal labor efficiencies. The original project budget assumed an internal labor budget of **[Begin Confidential]** [redacted] **[End Confidential]** for the removal of the damaged transmission towers. This budget amount was determined based on the timecards received during the first week of demolition. However, the internal crews performed work at a faster rate than anticipated which resulted in significant savings in the budget.

[130] *See*, Post Completion Review, submitted as Attachment 889-G in PGE's response to OPUC Data Request No. 889, provided in Confidential Exhibit 2005.

These two changes led to the final project cost being **[Begin Confidential]** [redacted] **[End Confidential]** higher than the original budget. The project was completed 45 days ahead of our initial target date and one week ahead of the contractor's commitment date. Our target in-service date was October 15, 2020; the line was safely energized on August 30, 2020.[131]

Q. Please summarize the prudence of PGE's investment in this project and why full cost recovery in this rate case is warranted.

A. As discussed in our Post Completion Report, submitted as Attachment 889-G to PGE's response to OPUC Data Request No. 889, this project was necessary to maintain a safe and reliable transmission system and allow for unaltered generation at our carbon-free Pelton-Round Butte hydro facilities. This project came in 45 days ahead of schedule and less than 1% over budget. The costs of this project were prudently incurred and should be included in rate base for cost recovery.

N. <u>Topic: P36913 - Transmission Line Clearance Mitigation</u>

Q. Please summarize Staff's Opening Testimony on Project P36913-Transmission Line Clearance Mitigation.

A. After reviewing the PJF and submitted discovery on the project, "Staff agrees that, in general, the Company should be addressing these clearance violations."[132] Staff stated that it "could not identify any clear evidence of overruns or mismanagement that would be an unfair burden to customers," but felt the PJF for this project was "particularly ambiguous and vague."[133]

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[131] *See*, Post Completion Review, submitted as Attachment 889-G in PGE's response to OPUC Data Request No. 889, provided in Confidential Exhibit 2005.
[132] Staff/700, Hanhan/33.
[133] Staff/700, Hanhan/33.

Staff has "no adjustment recommendations for this project" but stated it is "still reviewing" and "reserves the right" to provide additional adjustments.[134]

Q. Please discuss the cost management and prudence of investments in this project and provide supporting documentation.

A. P36913 provides funding for transmission pole replacements as part of the Transmission Line Clearance Mitigation (TLCM) project. The purpose of the TLCM project is to correct the approximately 1,000 potential clearance violations that were identified during a 2018 rating analysis of all PGE's 57kV and 115kV transmission lines. This inspection process was performed by Strategic Asset Management and Transmission Engineering. The inspection method used LiDAR, a surveying method using laser detection.[135] PGE collected and processed LiDAR data to substantiate ratings assigned to the transmission system facilities. The LiDAR data collected and subsequent interpretation allowed PGE to empirically verify line-to-ground clearances for its transmission system line loadings under both continuous and emergency Facility Ratings.[136] PGE has identified clearance discrepancies that could pose a risk to PGE employees, contractors, and members of the public coming into contact with an energized line. The TLCM remediation will address the identified clearance issues.[137]

This project was first brought to the August 2019 CRG with a request of **[Begin Confidential]** [redacted] **[End Confidential]** of 2019 planning funds; at the same time, the project manager informed the CRG of expected future requests of **[Begin Confidential]** [redacted] **[End Confidential]** for each of 2020 and 2021, with a total project rough order of magnitude of **[Begin Confidential]** [redacted] **[End Confidential]**. The 2019 planning

[134] Staff/700, Hanhan/33.
[135] *See*, "Description & Scope - Justification 1" in Confidential Exhibit 2007.
[136] *See*, "Impacts & Issues – Justification 1" in Confidential Exhibit 2007.
[137] *See*, "Risks, Dependencies, & Constraints – Justification 1" in Confidential Exhibit 2007.

funds of **[Begin Confidential]** [redacted] **[End Confidential]** was to design 150 transmission pole replacements. Transmission Engineering would partner with a contractor to design mitigations for the work. The request for **[Begin Confidential]** [redacted] **[End Confidential]** of planning funds was approved.[138]

In December 2019, 2020 funding of **[Begin Confidential]** [redacted] **[End Confidential]** for the design and construction of 300 transmission pole replacements was requested. The 2019 planning fund was reduced by **[Begin Confidential]** [redacted] **[End Confidential]**, allowing for the design of 100 transmission pole replacements. The requests were approved.[139]

The budget for 2020 capital funds was reduced throughout 2020 as a result of several factors. The first reduction was **[Begin Confidential]** [redacted] **[End Confidential]** in response to company-wide reductions in O&M and capital investments to mitigate COVID-19 pandemic impacts on customers. The second and third reductions of **[Begin Confidential]** [redacted] **[End Confidential]**, respectively, were due to portfolio cash-flow reviews and subsequent re-prioritization as the year-to-date spend signaled an execution timing risk.[140] This is an example of how PGE manages its overall capital portfolio to ensure the Company is investing in the right projects at the right time for customers.

At the November 2020 BSG and Authorization to Spend, **[Begin Confidential]** [redacted] **[End Confidential]** was requested for 2021, which would allow for the design and construction of 300 transmission pole replacements.[141] This request was approved.[142]

[138] *See*, "Description & Scope - Justification 1" and" Revision Summary" in Confidential Exhibit 2007.
[139] *See*, "Description & Scope – Justification 2" on page 12 of 15, and "Revision Summary" in Confidential Exhibit 2007.
[140] *See*, "Description & Scope – Justifications 3, 4 and 5" in Confidential Exhibit 2007.
[141] *See*, "Description & Scope – Justification 5" in Confidential Exhibit 2007.
[142] *See*, "Revision Summary" in Confidential Exhibit 2007.

Q. Based on the discussion above, please respond to Staff's assertion that the PJF for this project was "particularly ambiguous and vague" and that despite Staff not proposing any adjustment recommendations for this project in its Opening Testimony, it stated it is still reviewing the project and reserves the right to provide adjustments.

A. PGE has thoroughly documented the need for this project and the prudence of its investments. As shown in the PJF and summarized above, funding for this multi-year project was adjusted based on changing circumstances. 2020 funding was reduced across PGE in an effort to mitigate the pandemic's impact on customers. Some funding were re-prioritized to other projects as part of PGE's portfolio management. This is an example of how PGE prioritizes spending its limited capital funds and evaluates all projects both individually and at a portfolio level in order to maximize deployment of funds in service to customers. Finally, unavoidable labor shortages have impacted the executability of this project as planned. All of these circumstances are part of managing a large and complex portfolio of transmission capital investments. The modifications to the approved funding levels for this project through time highlights PGE's ongoing capital management and budget review and approval processes.

The need for funding is clearly documented in the PJF (to replace transmission poles that do not meet PGE's current clearance standards), and the changes to budget over time are also clearly documented in the PJF and summarized in the narrative above. It would be procedurally inappropriate and prejudicial to PGE for Staff to provide additional adjustments to this project in subsequent testimony.

O. <u>Topic: P17443 - T&D Major System Inspect, Replace</u>

Q. Please summarize Staff's Opening Testimony on Project P17443 – T&D Major System Inspect, Replace.

A. Staff did not have concerns with the construction of this project, noting the project 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."[143] Staff expressed concern that the FITNES program has identified **[Begin Confidential]** [redacted] "[144] **[End Confidential]**. Staff referred to PGE's response to OPUC Data Request No. 615 that showed increasing inspection volume and noted that PGE **[Begin Confidential]** [redacted] **[End Confidential]**.[146] Staff invited PGE to "address the issue of increasing costs for the FITNES program."[147] Staff had "no cost adjustment recommendations at this time" but reserved the right to provide additional adjustments.[148]

Q. Please respond to Staff's first question about the 2021 poles.

A. We assume that Staff meant to refer to PGE's response to OPUC Data Request No. 661 as our response to OPUC Data Request No. 615 did not provide information for 2021. In our response to OPUC Data Request No. 661, we state that the inspection volume for 2021 is

[143] Staff/700, Hanhan/43.
[144] Staff/700, Hanhan/44.
[145] Staff/700, Hanhan/44.
[146] Staff/700, Hanhan/44
[147] Staff/700, Hanhan/45.
[148] Staff/700, Hanhan/45.

30,166 poles. This refers to the forecast of the number of poles planned to be inspected in 2021.

Q. Please discuss the trend of costs for the FITNES program.

A. The FITNES program inspects and corrects violations in a ten-year cycle. Currently, the FITNES program is in the fourth year of the current cycle. Our answers will relate to the current FITNES inspection and correction cycle.

Inspection costs are operating expenses, not to be confused with capital replacement costs. Improvements to the inspection program have resulted in more pole assets (both distribution and transmission) being identified for replacement. As a result, the overall capital costs for the corrections have also increased. In addition, labor and material escalations have led to higher unit prices. Table 1 shows the total violation count for each year of this current ten-year cycle.

[Begin Confidential]

[redacted]

[End Confidential]

Additional resources are needed to meet the compliance requirements of OAR 860-024-0011 and OAR 860-024-0012, which aim to improve public safety and asset resiliency. Table 2 shows the number of work order completion counts and unloaded unit costs for this ten-year cycle. Since the beginning of this ten-year cycle, we have more than doubled the number of work orders we have completed, while keeping the average cost per work order roughly the same over the last four years.

[Begin Confidential]

Table 2.

[redacted]

[End Confidential]

Q. Based on the information provided above, what is your response to the OPUC Staff's concern about cost management of this project and recommended adjustment?

A. The FITNES program is intended to increase public safety in accordance with the guidelines set forth by the OARs, NESC, and Commission Safety Staff. The project management team actively manages costs by utilizing a competitive bid process to acquire the best unit prices while meeting the compliance deadlines. As Table 2 shows, we have more than doubled the amount of work undertaken while still managing to keep the average cost about the same over the last four years, despite increasing labor and material costs. There is no foundation upon which to disallow PGE's prudently incurred investments in this project.

P. Topic: P35572 - Rock Creek Substation

Q. Please summarize Staff's Opening Testimony on Project P35572 - Rock Creek Substation.

A. Staff acknowledged that "the project seems to be supported by load forecasts that support the transmission expansion."[149] However, because Staff believed the PJF and change orders were ambiguous, Staff claimed that it could not verify prudent management of costs and recommended that the Commission "disallow all the costs increases identified **[Begin**

[149] Staff/700, Hanhan/26.

Confidential] [redacted] **[End Confidential]** which amounts to **[Begin Confidential]** [redacted] **[End Confidential]**[151]

Q. Please discuss Staff's proposed disallowance of [Begin Confidential] [redacted]**. [End Confidential]**

A. It appears that Staff is referencing the increase of **[Begin Confidential]** [redacted] **[End Confidential]** associated with changing responsibility for the Rock Creek-Sunset 115kV line and the Rock Creek-185th 13kV feeder from PGE to an outside contractor.[152] The increase of **[Begin Confidential]** [redacted] **[End Confidential]** was partially offset by a budget decrease for internal labor savings associated with this project. PGE moved to an outside contractor in order to maintain the schedule. PGE needed to keep the project on schedule because it was necessary to serve load growth in the area. PGE manages schedules with the goal of keeping internal crews busy in order to maximize value to customers. However, when more outages occur than expected or when other project timelines change such that internal crews are unavailable, PGE sometimes must shift work to external contractors.

Q. Please discuss the origin and basis of the [Begin Confidential] [redacted] **[End Confidential] increase.**

A. It appears that Staff is referencing the **[Begin Confidential]** [redacted] **[End Confidential]** increase to the total project budget in September 2019.[153] This increase is primarily a result

[150] Staff/700, Hanhan/27.
[151] Staff/700, Hanhan/27.
[152] *See,* "Description & Scope – Justification 20" in Confidential Exhibit 2007.
[153] *See,* "Description & Scope – Justification 19" in Confidential Exhibit 2007.

of shifting from internal crew construction to an external contractor. There was also a slight increase in the construction costs for the new underground feeder.

Q. Please summarize your response to Staff's recommended disallowance.

A. Based on the foregoing, Staff's recommendation should be rejected. The cost increases identified by Staff were primarily related to shifting from internal labor to external labor and shifting schedules. Such changes may occur during multi-year, complex projects such as this one. As part of our overall cost management, PGE works to ensure internal crews are fully scheduled on projects. This means that there may be times when internal crews are not able to work on a particular project due to higher-than-normal outages or shifting timelines of other projects. In order to maintain the schedule of the project, external crews may be used. Relatedly, work may shift between years due to construction schedules, delivery of equipment, etc. This is part of managing the large portfolio of T&D projects. That does not mean the costs incurred are imprudent. To the contrary, the costs of this project have been demonstrated to be prudent and should be included in rate base for cost recovery.

Q. <u>Topic: P36229 - McGill Substation Project</u>

Q. Please summarize Staff's Opening Testimony on Project P36229 - McGill Substation Project.

A. Staff stated that the project "seems to be supported by load forecasts that support the transmission expansion."[154] Staff asserted that the PJFs for the project were "particularly ambiguous, such that a clear line between planning and execution was difficult to determine."[155] According to Staff, "[d]ue to the ambiguity of the change orders and the PJFs,"

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[154] Staff/700, Hanhan/30.
[155] Staff/700, Hanhan/30.

the Commission should disallow the delta between the **[Begin Confidential]** “[redacted] **[End Confidential]** when the budget was **[Begin Confidential]** [redacted] **[End Confidential]**and the final project cost of **[Begin Confidential]** [redacted], **[End Confidential]**resulting in a proposed disallowance of **[Begin Confidential]** [redacted]. **[End Confidential]**

Q. Staff chose [Begin Confidential] [redacted] [End Confidential]as the starting budget. Was this appropriate?

A. No. The project budget of **[Begin Confidential]** [redacted] **[End Confidential]** was an internal estimate provided in January 2019 for 2019 Authorization to Spend. This was made prior to two major changes, that were unknowable at the time, which impacted the total project budget. First, PGE received notice in April 2019 from Multnomah County of new permit requirements to engineer and construct Americans with Disabilities Act (ADA) ramps.[157] Second, additional scope was added to the project in September 2019.[158]

Q. Please describe the first major change that increased costs by [Begin Confidential] [redacted] [End Confidential] in April 2019.

A. The $685,000 increase was due to new permit requirements imposed by Multnomah County to engineer and construct ADA ramps. This had not been in the original scope or budget. Multnomah County did not have engineering standards for ADA ramps, which resulted in re-engineering costs and additional delays as the designs had to evolve based on ongoing

[156] Staff/700, Hanhan/30-31.
[157] *See,* “Description & Scope – Justification 10” in Confidential Exhibit 2007.
[158] *See,* “Description & Scope – Justification 11” in Confidential Exhibit 2007.

conversations with the County. Delays due to the permit negotiation, remobilization of internal crews, rental of civil construction equipment for ADA ramps, etc. resulted in increased costs. The permitting delays also resulted in an increase to capitalize property taxes for seven months.

Q. Please describe the second major change that increased by [Begin Confidential] [redacted] [End Confidential] in September 2019.

A. The $755,000 cost increase was due to the presence of a second high pressure gas line that had not been known previously, and was not revealed by survey work. PGE only became aware of a second high pressure (HP) gas line owned by Williams Pipeline (WP) during construction. One HP line was known during engineering; the second was not shown in survey data due to its depth. PGE initially planned to bore (drill a path underground) around the gas pipes facilities. However, WP was concerned that the cobbled soil condition could lead to a rock puncturing their lines. Therefore, PGE agreed to utilize a different construction approach to open trench (open dig) our lines underground rather than bore. This approach gave us more visibility to the soils and aided us in performing this work in a safe manner. However, this resulted in a cost increase because we had not intended to perform open trench construction. Additional costs for this type of construction included engineering, design, and permitting; increased labor costs; materials to perform the open trench; additional cable lengths and materials.

Q. How do you respond to Staff's recommendation to disallow $1.5 million?

A. The two major cost drivers were challenges with Multnomah County's unstated and unclear requirements to build ADA ramps, and the need to perform open trench construction instead of boring to avoid puncturing an HP gas pipeline. That pipeline did not appear during the survey due to its depth, so we were unaware of it during planning. Both of these changes were out of our control and were not foreseeable. We controlled costs as prudently as possible, but as with any large, complex project, not every single issue can be known in advance and funding has to change to address new issues. Staff's recommendation to disallow $1.5 million should be rejected because we have shown that PGE's investment in the project is prudent.

R. Topic: P35802 - Horizon Phase II Project

Q. Please summarize Staff's Opening Testimony.

A. Staff stated that the project "seems to be supported by load forecasts that support the transmission expansion."[159] However, Staff observed that **[Begin Confidential]** [redacted] **[End Confidential]** Staff stated that it was **[Begin Confidential]** "[redacted]." **[End Confidential]** Staff said that, as a result, they **[Begin Confidential]** "[redacted] **[End Confidential]**[160] Finally, Staff believed it **[Begin Confidential]** [redacted] **[End Confidential]**[161]

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[159] Staff/700, Hanhan/34.
[160] Staff/700, Hanhan/34-35.
[161] Staff/700, Hanhan/35.

Q. What is Staff's recommended adjustment?

A. Staff recommended the Commission disallow the **[Begin Confidential]** [redacted] **[End Confidential]** associated with the reclassification of funds. Staff also recommended a cost cap of **[Begin Confidential]** [redacted] **[End Confidential]** for this project.[162]

Q. Please respond to Staff's observation about the difference in the amount shown in the PJF and the amount requested for recovery in PGE's initial filing.

A. The difference is because the majority of this project closed prior to 2019. The fully loaded cost with AFUDC for this project is **[Begin Confidential]** [redacted] **[End Confidential]** closed to plant prior to 2019. We are asking for rate recovery of the **[Begin Confidential]** [redacted] **[End Confidential]**, fully loaded with AFUDC, that closed to plant in 2019.

Q. Please summarize Staff's testimony on the reclassification issue.

A. Staff stated they identified an accounting error in which the Company reclassified costs into this project from another project. Staff said that **[Begin Confidential]** "[redacted]." **[End Confidential]** Staff stated they **[Begin Confidential]** "[redacted]." **[End Confidential]**[163] Because Staff was uncertain about how PGE handled this issue, Staff simply proposed a disallowance.

[162] Staff/700, Hanhan/35.
[163] Staff/700, Hanhan/35.

Q. Please summarize how PGE treated the reclassification issue.

A. There was a shared contract and purchase order between the Horizon to Springville junction transmission line and the Shute to West Union transmission line. **[Begin Confidential]** [redacted]. **[End Confidential]**[165]

Q. How do you respond to Staff's proposed cost cap?

A. Given our explanation of the **[Begin Confidential]** [redacted] **[End Confidential]** reclassification, there is no justification for removing it from our filed request for recovery of **[Begin Confidential]** [redacted] **[End Confidential]** Additionally, there is no justification for capping this project simply because the PJF shows funds that were included in the previous rate case.

Q. What is your conclusion about Staff's proposed adjustments to this project?

A. PGE's investments in this project were handled properly and are fully justified. Staff's proposed disallowance should be rejected. Staff's unsupported, unexplained recommendation for a cost cap should likewise be rejected.

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[164] *See*, PGE's response to OPUC Data Request No. 695 provided in Confidential Exhibit 2005.
[165] *See*, "Description & Scope – Justification 13" in Confidential Exhibit 2007.

S. Topic: P36907 - Reconductor Murrayhill-St Marys

Q. Please summarize Staff's Opening Testimony on Project 36907 - Reconductor Murrayhill-St Marys (P36907).

A. Staff asserted that PGE "did not provide any documentation explaining project need from an electrical standpoint, though Staff had requested it."[166] Staff was unable to "identify any clear evidence for overruns or mismanagement" of costs, despite the PJF being "thin and ambiguous."[167] Staff has no adjustment recommendations for the project, but stated it is still reviewing the project and "reserves the right to provide additional adjustments."[168]

Q. Has PGE demonstrated the electrical need of this project?

A. Yes. On September 27, 2021, in response to OPUC Data Request No. 711, PGE provided the whitepaper explaining the electrical need of this project. As described in the whitepaper, the Murrayhill-St Marys 230kV transmission line is at risk of overloading for a single Contingency during light spring conditions with heavy South of Allston south-to-north path flow. Given the results of the whitepaper analysis as well as the time-critical nature of mitigating this potential single contingency overload, reconductoring the Murrayhill-St Marys 230kV line was the recommended initial course of action.[169]

Q. What was the estimated total project budget and what is the current expected incurred cost?

A. The estimated total project budget was **[Begin Confidential]** [redacted]. **[End Confidential]**[170] As of November 8, 2021, the vast majority of this project is in-service,

[166] Staff/700, Hanhan/38.
[167] Staff/700, Hanhan/39.
[168] Staff/700, Hanhan/39.
[169] *See*, "Murrayhill-St. Marys Overload Mitigation Analysis," page ii, provided as Highly Confidential Attachment A in PGE's response to OPUC Data Request No. 711, and provided in Highly Confidential Attachment 2006.
[170] *See*, "Business Need – Justification 1" in Confidential Exhibit 2007.

representing 95% of the project costs. The current expected incurred cost for this project is $5.1 million.[171] With 5% of costs outstanding, we expect this project to be under budget.

Q. Please summarize your response to Staff's Opening Testimony.

A. We demonstrated the electrical need of this project via submission of the whitepaper in our September 27, 2021 response to OPUC Data Request No. 711. This project is on track to be under budget upon completion later this year. PGE has thoroughly demonstrated the prudence of our investment in this project, which justifies inclusion of project costs in rate base. Finally, it would be procedurally inappropriate and prejudicial for Staff to provide additional adjustments to this project in subsequent testimony.

T. Topic: P36089 - Transm Full Pole Inspct & Replace

Q. Please summarize Staff's Opening Testimony.

A. Staff agrees that, in general, the Company should be proactively addressing the safety issue of failed poles.[172] Staff "could not identify any clear evidence for overruns or mismanagement that would be an unfair burden to customers." Although Staff asserted that the PJF was "ambiguous and vague," Staff made had no adjustment recommendations for the project. Staff stated they are still reviewing the project and "reserves the right" to provide additional adjustments.[173]

Q. How do you respond to Staff's Opening Testimony?

A. PGE has experienced several incidences of wood transmission pole failures involving multiple poles, where it appears the initial point of structural failure started well out of reach of a typical inspection from the ground level. An inspection program that includes a full pole

[171] *See*, "Revision Summary" in Confidential Exhibit 2007.
[172] Staff/700, Hanhan/40.
[173] Staff/700, Hanhan/40.

physical examination to detect internal cavities is currently the best way to determine if a wood pole has adequate remaining strength throughout the entire length of a pole.[174]

Since 2009, PGE had been working with Oregon State University to investigate full pole inspection (FPI) methods, including conducting large-scale pilot inspections over several years. The two cascading events in 2017 highlighted pole failures well above the groundline, reinforcing the value of a risk-based FPI program that complements the existing time-based regulatory FITNES program.[175]

The FPI program is risk-based, whereas the FITNES program is a time-based regulatory program. The FITNES inspection includes a detailed visual NESC inspection and treatment of the pole, all performed at the ground level. The FPI identifies poles to receive a "full-length" inspection based on pole attributes and the consequence of pole failure.[176]

The cost controls on this project follow the base guidelines that all projects follow and as have been discussed throughout this testimony. Cost drivers include general cost escalation in materials and labor, as these poles are generally replaced with internal resources.

PGE has thoroughly demonstrated the prudence of our investment in this project, which justifies inclusion of project costs in rate base. It would be procedurally inappropriate and prejudicial to PGE for Staff to provide additional adjustments to this project in subsequent testimony.

U. Topic: P35679 - Marquam Substation

Q. Please summarize Staff's Opening Testimony on Project P35679 - Marquam Substation.

[174] *See*, "Description & Scope – Justification 9" in Confidential Exhibit 2007.
[175] *See*, PGE's response to OPUC Data Request No. 717, submitted on September 27, 2021, provided in Confidential Exhibit 2005.
[176] *See*, PGE's response to OPUC Data Request No. 715, submitted on September 27, 2021, provided in Confidential Exhibit 2005.

A. Staff asserted that the non-loaded cost in the PJF appeared to be nearly three times the cost shown in PGE's response to OPUC Data Request No. 311 **[Begin Confidential]** [redacted] **[End Confidential]** versus **[Begin Confidential]** [redacted] **[End Confidential]**. Staff recommends disallowing **[Begin Confidential]** [redacted] **[End Confidential]**, which is the sum of "particularly problematic" cost increases of **[Begin Confidential]** [redacted] **[End Confidential]**. Based on the loadings ratio Staff calculated, this would amount to a total disallowance of **[Begin Confidential]** [redacted]. **[End Confidential]**[177]

Q. Why did Staff characterize these budget increases as "particularly problematic"?

A. It is unclear. Staff based its proposed disallowances for this project on Staff's assertion that the PJFs were ambiguous, rather than any specific evidence of mismanagement or identification of concerns about individual budget increases.[178]

Q. Are any of these budget increases "problematic"?

A. No, PGE would not characterize these budget increases as "problematic." While PGE would prefer to avoid budget increases, at times they are an unavoidable part of project construction. Staff appears to misunderstand the relationship between the costs in the PJF and PGE's initial filing—there is no cost increase associated with the higher costs reflected in the PJF. Moreover, each of the <u>actual</u> budget increases for this project was justified by various contingencies, the increased costs were prudently managed by PGE, and the overall project costs were reasonable.

Q. Why are the costs shown in the PJF nearly three times as large as what was included in PGE's initial filing?

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[177] Staff/800, Sayen/20-22.
[178] Staff/800, Sayen/22.

A. This project began in 2014; the majority of the project costs closed prior to January 2019, meaning those costs were included in PGE's last GRC. This request includes only the amount of plant additions that close between January 1, 2019 through April 30, 2022, which is **[Begin Confidential]** [redacted] **[End Confidential]**.

The table below shows the breakdown of the $35.4 million close to plant that is included in this rate case for cost recovery: **[Begin Confidential]**

[redacted]

[End Confidential]

Q. Please respond to the first disallowance of [Begin Confidential] [redacted] **[End Confidential] Staff proposed.**

A. Staff's first proposed disallowance was for the **[Begin Confidential]** [redacted] **[End Confidential]**[179] This is not applicable to this rate case because this was related to the Marquam substation scope, which was placed in service in April 2018.

Q. Please respond to the second disallowance of [Begin Confidential] [redacted] **[End Confidential] Staff proposed.**

A. Staff's second proposed disallowance was for **[Begin Confidential]** [redacted] **[End Confidential]**[180] This is not applicable to this rate case because this was related to the Marquam substation scope, which was placed in service in April 2018.

[179] Staff/800, Sayen/21.
[180] Staff/800, Sayen/21.

Q. Please respond to the third disallowance of [Begin Confidential] [redacted] **[End Confidential] Staff proposed.**

A. Staff's third proposed disallowance was for **[Begin Confidential]** [redacted] **[End Confidential]**[181] This is not applicable to this rate case because this was related to the Harrison-Marquam Line scope, which was placed in service in April 2018.

Q. Please respond to the fourth set of disallowances of [Begin Confidential] [redacted] **[End Confidential] Staff proposed.**

A. Staff's fourth set of proposed disallowances are for costs included in this GRC and were related to **[Begin Confidential]** [redacted] **[End Confidential]**[182]

This was for the Stephens South Network Conversion and the Stephens North Network Cutover AWOs, which were placed in service in March 2019. The increased costs were due to issues out of PGE's control and despite PGE's efforts to obtain the information necessary to make informed estimates. Despite running into unexpected challenges outside of our control, we prudently managed costs. Below is a detailed explanation of each cost change: **[Begin Confidential]**

[181] Staff/800, Sayen/21.
[182] Staff/800, Sayen/21.

- [redacted]
- [redacted]
- [redacted] **[End Confidential]**

Q. Please respond to the final disallowance of [Begin Confidential] [redacted] [End Confidential] proposed by Staff.

A. Staff's final proposed disallowance was **[Begin Confidential]** [redacted] **[End Confidential]**.

Confidential Exhibit 2008 provides the complete PJF.

The first item that was cut off was related to Marquam Radial Substation increases, placed in service in March 2019, totaling **[Begin Confidential]** [redacted]. [redacted]

[End Confidential].

Q. Given the foregoing, please respond to Staff's proposals in Opening Testimony.

A. The PJF showed the entire project costs, which began in in 2014, meaning the majority of the project costs closed prior to January 2019 and were included in the last rate case. This case includes only the amount of plant additions that close between January 1, 2019 through April 30, 2022, which is **[Begin Confidential]** [redacted] **[End Confidential]**.

Some of the specific disallowances Staff proposed were for items not included in this rate case (i.e., they are costs that closed to plant prior to 2019). For the remaining disallowances, the cost increases were due to unforeseen circumstances despite our best efforts to obtain information in advance. However, we prudently managed the increased costs when these unexpected issues arose. Thus, Staff's recommended disallowances should be rejected, and our request of **[Begin Confidential]** [redacted] **[End Confidential]** should be included in rate base for recovery.

V. Topic: Blanket Projects

Q. Please summarize Staff's Opening Testimony on the topic of Blanket Projects.

Staff asserts that PGE's PJFs lack sufficient information to determine how costs were managed for blanket projects. Staff proposes no actual adjustments but invites PGE to clarify its cost control process and protocols, accountability mechanisms, and its processes to plan, maintain and meet budget targets. Staff states they are still reviewing blanket projects and "reserve the right" to propose disallowances in future rounds of testimony.[183]

Staff reviewed eight blanket projects for which it raised general concerns about cost management: Distribution System Construction II, Distribution Customer Line Construction II, Replace Failed Underground Cables; Outage or Emergency Replacement; Unjacketed Cable Replacement Program; Purchase Distribution Transformers; street and area light construction; and purchase customer meters.

Q. How do you respond to Staff's assertions?

A. We disagree with Staff's assertions that PGE's cost controls are inadequate. We appreciate the opportunity to more clearly explain our cost control measures both for blanket projects generally and for the specific projects listed in Staff's Opening Testimony.

Q. What are "blanket" projects?

A. Blanket projects are ongoing core investments required to sustain our system and provide new or expanded electrical service to customers.[184] Because these projects are ongoing, it would be unwieldy and inefficient to have a specific project number and request for each activity within a blanket project. For example, the blanket project "purchase customer meters" allows

[183] Staff/800, Sayen/28-29.
[184] *See*, PGE's response to OPUC Data Request No. 660, submitted on September 27, 2021, provided in Confidential Exhibit 2005.

us to purchase customer meters in aggregate, instead of developing a project justification for each single customer meter we need to purchase.

Q. Please summarize the cost controls that apply to all blanket projects.

A. All Blanket projects are subject to the processes described in Exhibit 1800. All Blanket projects must provide monthly reports to the capital Portfolio team. Each month, the capital portfolio team carefully analyzes the monthly reports, with particular attention to budgetary variances, and monitors project sensitivities. Recommendations for approval or disapproval are brought to the monthly BSG.

Q. Before addressing the specific Blanket projects noted in Staff's Opening testimony, do you have any observations regarding cost trends across all blanket projects?

A. Yes. While the impacts of broad cost trends are not unique to blanket projects, they are particularly relevant to blanket projects, given their ongoing nature. With respect to the cost drivers impacting PGE's current filing, PGE has seen increases of 2-3% annually across all projects due to labor cost increases. While this is lower than the current rate of inflation, it nevertheless impacts PGE's costs.

In addition to this trend, other specific issues have arisen that require attention. One example is the recent wage increase provided to journeyman classification employees. Based on a wage comparison for IBEW Local 125, we learned that PGE journeymen were compensated significantly below average among Oregon and southwest Washington utilities. PGE journeymen compensation was ranked twenty-third out of the twenty-six utilities surveyed.[185] In order to provide competitive wages to retain and recruit journeymen, PGE

[185] *See,* Confidential Exhibit 2009.

increased journeymen wages by 10% in 2019. PGE believes this increase was reasonable and appropriate.

In addition to increased labor costs, PGE has seen increased demand for line resources due to an increasing number of projects driven by resiliency, compliance, and municipal requirements. For example, with the passage of Oregon House Bill 2017, "Keep Oregon Moving," we have seen a marked increase in the amount of road improvement and capital projects mandated by municipalities and counties. The status of these projects can change quickly, and PGE is expected by the county or municipality to adjust accordingly. Oftentimes, our internal resources are unable to adjust to the volume of work, so we contract with external labor resources to complete such projects. Another driver in labor costs are more frequent storms which have required PGE to augment labor using contracted labor.

Q. Please briefly describe the work order management system PGE uses.

A. PGE uses Maximo work order management system to manage the flow of work orders throughout the Company, including requisite manager approval. To be clear, work orders are different from purchase orders or change orders. Work orders are used to manage the flow of work internally at PGE.

Q. Please provide more information on the "Distribution System Construction II" blanket project.

A. The T&D System Construction blanket covers T&D general construction activities related to emerging distribution additions, damaged asset replacement, and accelerated capital construction. In addition to the BSG/CRG monitoring processes, PGE controls costs in the following ways:

- PGE tracks these activities in the Maximo work order management system. As work orders are written and designed, the Maximo work order system sends the work order for management approval. Management reviews the work order estimates and design drawings before approval.
- In addition to system-driven authorizations, PGE's T&D design department has policies on Maximo estimation thresholds and the level of approvals required before the work is approved.
- The Line Dispatch department prioritizes work based on set criteria and schedules the job accordingly.
- Generally, the work conducted in the Distribution System blanket is reactive and is budgeted based on historical trends.

Q. Please provide more information on the "Distribution Customer Line Construction II" blanket project.

A. The Distribution Customer Line Construction covers customer-driven requests, including customer service requests, commercial developments, and developer-driven subdivision projects. In addition to the BSG and CRG monitoring and review processes, PGE controls costs in the following ways:

- PGE tracks Customer Blanket work activities in the Maximo work order management system. Work follows the same authorizations as discussed for the Distribution System Construction blanket.
- In addition to system-driven authorizations, PGE's T&D design department has policies on Maximo estimation thresholds and the level of approvals required before the work is approved.

- The Line Dispatch department prioritizes work based on set criteria and schedules the job accordingly.
- Generally, the Customer blanket's work depends on customer demand and is budgeted based on historical trends.

Q. Please provide more information on the "Replace Failed Underground Cables" blanket project.

A. PGE's Replace Failed Underground Cables (also called Reactive Cable Replacement) program is a longstanding body of work that addresses actively failing underground cables (all cable types at primary and secondary voltages). In 2018, the Generation Transmission & Distribution Project Management Office (Gen T&D PMO) took control of the project to improve oversight and controls.

Projects initiated in the Reactive Cable Replacement Program start with recommendations from PGE's skilled team of distribution linemen, and special testers after responding to cable failures. PGE bases replacement requests on the presence of duct, fault history, test results, fault location, and repairability. Once the replacement is requested, the Distribution Operations Engineer responsible for the feeder develops a scope of work. The engineer focuses on addressing the segment with the identified issue and with a secondary focus on adjacent cable. If an adjacent cable is the same type/vintage and has a demonstrable history of power quality issues, they may add additional segments to the scope. To limit scope creep and ensure equitable application of funds across regions and feeders, the engineer escalates requests that have more than three segments to the Program Manager for review and approval before design.

After scope development, all detailed design workflows through standard processes and procedures are within a contract design team. Design Project Managers develop designs by contract and typically include additional related equipment replacement (bad order vault lids or live front transformers). All Reactive Cable work orders are subjected to a rigorous internal review process by contract leads before being submitted to PGE distribution project manager engineer support management for final review and approval. Additional cost control occurs through a competitive bid process for civil construction (installation of vaults and conduits). The PGE Program Manager reviews and approves all civil bids and change requests. All related electrical line workflows through regular PGE processes/procedures are subject to the same oversight as any other distribution line work.

Jobs exceeding $20,000 in civil construction are also individually vetted by the project manager. The PMO team continues to evaluate the Replace Failed Cable project for process improvements and is considering changes to improve efficiencies and cycle time.

Programmatic management by the PMO team encourages the following centralized decision making and process controls:

- Monthly financial and reporting measures as is required for all work within the Gen T&D PMO.
- Monthly reporting and budgetary monitoring of variances.
- Monitoring of project transactions and adjustment and accounting for outlier projects with high dollar values.
- Assignment of AWOs for additional tracking and coordination
- Historical averages to determine budget requests due to the reactive nature of the work.

Q. Please provide more information on the "Unjacketed Cable Program" blanket project.

A. PGE's Unjacketed Cable Replacement program executes large-scale cable replacement projects to reduce the company's risk associated with the substantial quantity of direct buried primary voltage cable with an exposed concentric neutral. Individual projects replace all such primary cables within a specified boundary with modern jacketed cable installed in vault-to-vault duct-based system.

All work executed in the Unjacketed Cable Replacement Program is scoped and developed within the Program Management team through a partnership with a broad cross-section of input and support from PGE subject matter experts, including asset management, special testers, operations engineers, planners, key customer managers, government affairs, and property specialists.

Areas with large concentrations of direct buried primary cable are reviewed for fault frequency and known power quality issues. The following conditions drive project complexity: municipal permitting challenges, field conditions including known rocky soil, utility congestion, moratorium due to recent pavement overlay, presence of existing easements, and existing power configuration (back lot power, presence of radial lines). PGE selects a variety of areas across multiple regions, municipalities, and anticipated difficulty levels. This selection process reduces the risk of consolidation in a single location and gives the team tools to add stability to program-level finances. Project diversity within the program provides flexibility and the ability to respond to unexpected setbacks by relocating workforces to other equally important areas while maintaining financial targets. Year-ahead design and planning to develop shovel-ready work also allows for incremental up/downscaling should the needs of the portfolio impact overall annual budgets mid-cycle.

Contract business partners design and execute projects within the Unjacketed Cable Replacement Program, using a turnkey methodology. This work includes detailed design, civil construction, electrical construction, and hard/soft surface restoration. Program tenets key to the successful execution of the work and the team's ability to meet financial targets include:

- Fully unitized cost structure
- 100% design validation (PGE inspects and documents all vaults and transformers; cable types are confirmed early in detailed design)
- Robust contractor design review process
- PGE management review and approval of all projects
- Dedicated PGE Construction Management support through all phases of work
- 100% inspection for quality and completion before contractor final invoicing

Q. What is the relationship between "Replace Failed Underground Cables" and "Unjacketed Cable Program" blanket projects?

A. The Reactive and Unjacketed Cable Replacement Programs have multiple touch points and are managed by the same team within the Gen T&D PMO. The Reactive program often serves to help identify areas where scope expansion to the large scale of work in the Unjacketed program is justified, and in return, the agility of reactive projects allows for immediate outages to be addressed at a small scale within areas that are planned for large scale replacement in future years. While areas that have had the benefit of large-scale replacement in the Unjacketed program typically only see failures due to secondary cable or dig-ins, the amount of investment in that program has not been sufficient to cause a reduction in PGE's annual reactive spend; however, it has helped to curb its growth.

Q. Please provide more information on the "Outage or Emergency Replacement" blanket project.

A. The Outage or Emergency Replacement project captures costs related to outage restoration, damage, and storm damage. Financial transactions in this funding project are analyzed monthly. A financial analyst reviews work orders and financials to ensure crews properly account for operating and capital costs. The financial analyst will transfer any charges found that are not part of Outage or Emergency replacement project or not a replacement of a Capital Asset. PGE's Asset Accounting department will review capital storm costs assigned accounting based on the storm's size. Emergency restoration work is limited to restoration activity. If crews identify additional work required after the initial restoration, the crew will create a separate work order designated to the appropriate accounting category. PGE establishes storm accounting for the damage that occurs during the storm event, and corrective activities include any identified storm damage. Work in this category is reactive; analysts base budgets upon minimum historical trends.

Q. Please provide more information on the "Purchase Distribution Transformers" blanket project.

A. Transformers, like most inventory used for construction, are purchased to meet demand from various construction projects.

Factors that have increased spending associated with the Purchase Distribution Transformer Project are listed below:

- Transformer usage has steadily increased, both due to new customer demand and restoration demands from more frequent storms.

- Like most other construction materials PGE purchases, the landed cost of transformers continues to increase, year after year. 2021 is significant as we've seen transformer manufacturer pricing increase between 5-15% as raw material prices increase. Another factor raising prices is increasing manufacturer lead-times and slipping delivery dates; PGE is forced to spot-purchase a significant number of transformers to restore power during large storms and protect our customers at a much higher cost.
- PGE strives to maintain the lowest inventory levels necessary to provide the highest level of restoration and customer service. Unfortunately, the pandemic has interrupted the continued supply of many of our construction materials, including transformers. To protect our ongoing commitment to support our customers, PGE has increased transformer inventory to mitigate extreme shortages in both manufacturing and market supply. PGE expects transformer inventory levels will return to pre-2021 levels by the end of the second quarter of 2022.

Q. Please provide more information about the "Street and Area Light Construction" blanket project.

A. The Street and Area Light Construction project designs and constructs lighting installations, removals, and upgrades for municipalities, property developers, residential and commercial customers, and LED conversions. Like other T&D work, PGE tracks this work in Maximo, PGE's work management system. As work orders are written and designed, the Maximo work order system sends the work order for management approval. Management reviews the work order estimates and design drawings before approval. In addition to system-driven authorizations, PGE's T&D design department has policies on Maximo estimation thresholds and the level of approvals required before the work is approved. Cost controls for each segment are summarized below.

For daily new construction, cost control measures include:

- Reduction of PGE's catalog of lighting offerings which helps us get better quantity prices by buying more of one item rather than smaller quantities of more lighting options.
- PGE recoups the cost of the fixtures via the tariff, and PGE is made whole on these costs. PGE updates the tariff regularly for the cost of materials and new items added when the Lighting department removes older obsolete items.

For the conversion of non-LED lights to LED lights, cost control measures include:

- Facilitation of bulk cost reductions by forecasting our need for the upcoming year and informing the manufacturers of the prior year.
- In cases where we are converting from option B (customer owns) to option A (PGE owns) or lights that are currently an option A, the tariff schedule for Option A lights provides full recovery, both in labor and material costs.
- By picking the best quality light with the best performance, we prolong replacement and upgrade cycles while also having reliability, limiting in-field repair costs.

We manage labor costs in several ways. First, for daily ongoing new construction, we acquire and schedule resources through the Line Dispatch and Line departments. The Line Dispatch department prioritizes work based on set criteria and schedules the jobs accordingly. For LED conversion projects, Outdoor Lighting Services identifies the project scope, including the number of lights, the geographic area, and standards of construction, and provides this information to Contract Services for the competitive bid process. Once Contract

Services collects the bids, they give them to Outdoor Lighting Services to decide which contractor to use. To date, we have always picked the lowest-cost bid.

Q. Please provide more information about the "Purchase Customer Meters" blanket project.

A. The Purchase Customer Meters project purchases meters based on demand from various projects. These projects utilized the meters for the replacement of failed and obsolete meters. This project also includes the labor to replace failed and obsolete meters. Forecasts of meters is based on historical run rates and storeroom inventory counts.

Q. Please summarize how PGE prudently invests in and manages its blanket projects.

A. Blanket projects are an integral piece to PGE's core mission of maintaining a safe and reliable T&D system. Given the ongoing nature of this work, it would be unwieldy to require each spend to have its own project and gating process. For example, that would mean each light PGE converts from non-LED to LED would require its own project justification form and project number. However, that does not mean we do not have strict budget controls and management processes in place for blanket projects.

The spending on blanket projects is analyzed monthly by the portfolio management team and the BSG is kept informed of their status. If there is a concerning cost variance, this is investigated by the portfolio management team and reported to the BSG. In addition to these monthly control processes, we have strict processes in place for the procurement of goods which compose the majority of the costs of these blanket projects. We have shown above how we work to ensure the most competitive prices for materials acquisitions, such as providing advance notice to manufacturers we have an established relationship with to obtain lower unit costs; using the Maximo work management system to ensure management review of work order estimates and drawings prior to approval; and implementing efficiencies in inventory management.

PGE has demonstrated the prudence of its investment in these vital projects and full cost recovery should be approved.

V. Summary and Conclusions

Q. Please summarize your position on recovery of wildfire mitigation and vegetation management costs.

A. The Commission should reject Staff's proposed PBRM as it is punitive, conflicts with the law, and misaligns metrics and consequences. PGE has demonstrated the prudence of its investments in both wildfire mitigation and vegetation management, and Staff has affirmed as much. The Commission should provide full recovery of the wildfire mitigation and vegetation management costs sought by PGE in this proceeding. If, despite all evidence to the contrary, the Commission proceeds with implementing a punitive PBRM, the mechanism should be revised to better align the metric with the consequence. Specifically, the metric should be *only* vegetation management violations in high risk fire zones and the funding affected should *only* be that specific to vegetation management in high risk fire zones, which is AWRR. Moreover, the Commission should ensure that any probable violations identified by Staff are appropriately validated as actual violations before any penalties would apply.

Finally, the Commission should adopt an AAC as provided in SB 762 and described in Exhibit 2200/Macfarlane-Tang.

Q. Please summarize your position on the prudence of PGE's capital investments in ADMS.

A. We provide detailed explanations for each vendor and services rendered for the ADMS capital funds included in rate base. Staff did not question the prudence of PGE's decision to invest in ADMS but asked for more information on the cost components. We have shown our prudence in our ADMS capital investments and the full amount should be included in rate based.

Q. Please summarize your position on certain T&D capital investments.

A. We have provided detailed explanations for each proposed disallowance. In some cases, Staff struggled to interpret the PJF, and we have provided the narrative behind the PJF and the budget changes that were unclear to Staff. Staff's general reservation to make additional adjustments is prejudicial to PGE and should be rejected. Coupled with the explanation of our cost control management and budgeting practices provided in Exhibit 1800 and our detailed justifications of incurred costs, we have demonstrated prudence in our T&D capital investments and full recovery should be included in rate base.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit	**Description**
2001-C	ADMS Logical Architecture
2002-C	ADMS Training Strategy
2003	Summary of Discovery Provided by PGE Regarding Projects Identified in Staff's Opening Testimony
2004	PGE's Responses to Data Requests
2005-C	PGE's Responses to Data Requests, Including Certain Whitepapers
2006-HC	PGE's Responses to Data Requests, Including Certain Whitepapers
2007-C	Project Justification Forms
2008-C	Complete PJF for P35679 - Construct Marquam Project
2009-C	Wage Comparison for IBEW Local 125

Exhibits 2001-2002, 2005,
2007-2009 are confidential and
provided only in electronic format.
Exhibits are subject to
General Protective Order 21-206

The tables below show the information PGE has provided for each project referenced in OPUC Staff's Opening Testimony.

P36879 - ADMS	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
142	July 23, 2021
195	August 12, 2021
198 Revised	September 1, 2021
291	August 19, 2021
309	August 20, 2021
311	August 20, 2021
765	September 28, 2021
833	October 1, 2021
871	October 6, 2021
889	October 13, 2021
PGE's Response to AWEC Data Request No.:	**Date of Submission:**
006	August 24, 2021
PGE Direct Case:	**Date of Submission:**
Exhibit 800, pages 29-37	July 9, 2021

P36501 - Integrated Operations Center	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
Supplemental 198 (PJF)	September 1, 2021
142	July 23, 2021
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291	August 19, 2021
309	August 20, 2021
311	August 20, 2021
329	August 20, 2021
330	August 20, 2021
656	September 27, 2021
657-A (complete PJF) 657-B (change orders)	September 27, 2021
658-A (business case) 658-B (narrative to support PowerPlan Revisions)	September 27, 2021
658	September 27, 2021
765	September 28, 2021
869 (change order documentation)	October 5, 2021
871	October 6, 2021
889	October 13, 2021
PGE's Response to AWEC Data Request No.:	**Date of Submission:**
006	August 24, 2021
228	October 19, 2021
PGE Direct Case:	**Date of Submission:**
PGE Exhibit 800, Section IV PGE Exhibit 803 PGE Exhibit 804 PGE Exhibit 805 PGE Exhibit 806 PGE Exhibit 807	July 9, 2021

P36708 - Butler Substation	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
142	July 23, 2021
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291	August 19, 2021
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307	August 20, 2021
309	August 20, 2021
311	August 20, 2021
326	August 20, 2021
329 (included one-line diagram)	August 20, 2021
330 (included project timeline)	August 20, 2021
334	August 20, 2021
573	September 8, 2021
574 (included MLA)	September 8, 2021
575	September 8, 2021
631 (included change orders)	September 17, 2021
662	September 27, 2021
663	September 27, 2021
765	September 28, 2021
869 (included change order documentation)	October 5, 2021
871 (included project timeline)	October 6, 2021
889* - PGE chose to provide additional information on this project in its response to OPUC Data Request 889, although this project was <u>not</u> included in OPUC Data Request 889. Information on this project was provided in Attachment C (BSG monthly packet) and Attachment H (initial gate checklist)	October 13, 2021
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309	August 20, 2021
311	August 20, 2021
326	August 20, 2021
329	August 20, 2021
330	August 20, 2021
334	August 20, 2021
580	September 8, 2021
630	September 17, 2021
682	September 27, 2021
683	September 27, 2021
765	September 28, 2021
869	October 5, 2021
871	October 6, 2021
889	October 13, 2021
PGE's Response to AWEC Data Request No.:	**Date of Submission:**
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PGE Direct Case:	**Date of Submission:**
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P36763 - Install Horizon VWR3 Transformer	
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195	August 12, 2021
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291	August 19, 2021
303	August 20, 2021
304	August 20, 2021
307	August 20, 2021
309	August 20, 2021
311	August 20, 2021
329, Attachment A (one-line diagram)	August 20, 2021
330	August 20, 2021
334, Attachment A (whitepaper)	August 20, 2021
582	September 8, 2021
705	September 27, 2021
706	September 27, 2021
707	September 27, 2021
708	September 27, 2021
709	September 27, 2021
765	September 28, 2021
871	October 6, 2021
889, Attachments C (BSG monthly packet) and H (initial gate checklist)	October 13, 2021
891	October 7, 2021
PGE's Response to AWEC Data Request No.:	**Date of Submission:**
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PGE Direct Case:	**Date of Submission:**
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P36039 – Harborton Reliability Project Phase 1	
PGE’s Response to OPUC Data Request No.:	**Date of Submission:**
142	July 23, 2021
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198 Revised	September 1, 2021
291	August 19, 2021
303	August 20, 2021
304	August 20, 2021
306	August 20, 2021
307	August 20, 2021
311	August 20, 2021
326	August 20, 2021
329	August 20, 2021
330	August 20, 2021
335	August 20, 2021
479	August 31, 2021
581	September 8, 2021
664	September 27, 2021
666	September 27, 2021
667	September 27, 2021
668	September 27, 2021
669	September 27, 2021
765	September 28, 2021
869	October 5, 2021
871	October 6, 2021
889	October 13, 2021
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PGE Direct Case:	**Date of Submission:**
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309	August 20, 2021
311	August 20, 2021
765	September 28, 2021
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889	October 13, 2021
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P36910 – Outer Division Multi Project	
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198 Revised	September 1, 2021
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P36861 – Division Transit Project	
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309	August 20, 2021
311	August 20, 2021
326	August 20, 2021
329	August 20, 2021
330	August 20, 2021
332	August 20, 2021
338	August 20, 2021
339	August 20, 2021
765	September 28, 2021
871	October 6, 2021
889	October 13, 2021
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291	August 19, 2021
303	August 20, 2021
304	August 20, 2021
306	August 20, 2021
307	August 20, 2021
311	August 20, 2021
326	August 20, 2021
329	August 20, 2021
330	August 20, 2021
334	August 20, 2021
479	August 31, 2021
627	September 17, 2021
677	September 27, 2021
678	September 27, 2021
679	September 27, 2021
680	September 27, 2021
681	September 27, 2021
765	September 28, 2021
869	October 5, 2021
871	October 6, 2021
889	October 13, 2021
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P36270 - Roseway Substation	
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291	August 19, 2021
304	August 20, 2021
306	August 20, 2021
307	August 20, 2021
311	August 20, 2021
326	August 20, 2021
329	August 20, 2021
330	August 20, 2021
334	August 20, 2021
577	September 8, 2021
578	September 8, 2021
629	September 17, 2021
687	September 27, 2021
765	September 28, 2021
869	October 5, 2021
871	October 6, 2021
889	October 13, 2021
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291	August 19, 2021
304	August 20, 2021
311	August 20, 2021
619	September 17, 2021
697	September 27, 2021
698	September 27, 2021
699	September 27, 2021
700	September 27, 2021
701	September 27, 2021
702	September 27, 2021
703	September 27, 2021
765	September 28, 2021
814	October 1, 2021
871	October 6, 2021
889	October 13, 2021
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P37062 - Rebuild Grizzly-RB 500kV Towers	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
195	August 12, 2021
305	August 20, 2021
307	August 20, 2021
311	August 20, 2021
718	September 27, 2021
765	September 28, 2021
871	October 6, 2021
889	October 13, 2021
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P36913-Transmission Line Clearance Mitigation	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
143	July 23, 2021
195	August 12, 2021
198 Revised	September 1, 2021
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309	August 20, 2021
311	August 20, 2021
704	September 27, 2021
765	September 28, 2021
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143	July 23, 2021
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615	September 17, 2021
661	September 27, 2021
765	September 28, 2021
839	October 1, 2021
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P35572 - Rock Creek Substation	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
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304	August 20, 2021
307	August 20, 2021
311	August 20, 2021
326	August 20, 2021
329	August 20, 2021
330	August 20, 2021
334	August 20, 2021
618	September 17, 2021
684	September 27, 2021
685	September 27, 2021
686	September 27, 2021
765	September 28, 2021
869	October 5, 2021
871	October 6, 2021
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P36229 - McGill Substation Project	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
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304	August 20, 2021
307	August 20, 2021
311	August 20, 2021
326	August 20, 2021
329	August 20, 2021
330	August 20, 2021
334	August 20, 2021
622	September 17, 2021
688	September 27, 2021
689	September 27, 2021
690	September 27, 2021
765	September 28, 2021
869	October 5, 2021
871	October 6, 2021
889	October 13, 2021
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P35802 - Horizon Phase II Project	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
142	July 23, 2021
195	August 12, 2021
198 Revised	September 1, 2021
307	August 20, 2021
311	August 20, 2021
330	August 20, 2021
335	August 20, 2021
582	September 8, 2021
691	September 27, 2021
692	September 27, 2021
693	September 27, 2021
694	September 27, 2021
695	September 27, 2021
696	September 27, 2021
705	September 27, 2021
765	September 28, 2021
869	October 5, 2021
871	October 6, 2021
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PGE's Response to OPUC Data Request No.:	**Date of Submission:**
143	July 23, 2021
195	August 12, 2021
Supplemental 198 (PJF)	September 1, 2021
291	August 19, 2021
306	August 20, 2021
307	August 20, 2021
309	August 20, 2021
311	August 20, 2021
710	September 27, 2021
711 (whitepaper)	September 27, 2021
712	September 27, 2021
765	September 28, 2021
871	October 6, 2021
889 – Attachment C (BSG monthly packets), Attachment D (Operations Executive Steering Committee monthly packets), and Attachment H (initial gate checklist)	October 13, 2021
890	October 7, 2021
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P36089 - Transm Full Pole Inspct & Replace:	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
142	July 23, 2021
143	July 23, 2021
195	August 12, 2021
198 Revised	September 1, 2021
291	August 19, 2021
306	August 20, 2021
307	August 20, 2021
311	August 20, 2021
713	September 27, 2021
714	September 27, 2021
715	September 27, 2021
716	September 27, 2021
717	September 27, 2021
765	September 28, 2021
871	October 6, 2021
889	October 13, 2021
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006	August 24, 2021

P36341 - St Marys Battery Addition	
PGE’s Response to OPUC Data Request No.:	**Date of Submission:**
142	July 23, 2021
195	August 12, 2021
198 Supplemental	September 1, 2021
291	August 19, 2021
303	August 20, 2021
304	August 20, 2021
311	August 20, 2021
313	August 20, 2021
626	September 17, 2021
719	September 27, 2021
720	September 27, 2021
721	September 27, 2021
765	September 28, 2021
869	October 5, 2021
871	October 6, 2021
889	October 13, 2021
PGE’s Response to AWEC Data Request No.:	**Date of Submission:**
006	August 24, 2021
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237	October 19, 2021

P35679 - Marquam Substation	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
142	July 23, 2021
195	August 12, 2021
198 Supplemental	September 1, 2021
304	August 20, 2021
306	August 20, 2021
311	August 20, 2021
326	August 20, 2021
329	August 20, 2021
330	August 20, 2021
334	August 20, 2021
671	September 27, 2021
765	September 28, 2021
871	October 6, 2021
889 – Attachment C (BSG monthly packets), Attachment G (Post Completion Review)	October 13, 2021
PGE's Response to AWEC Data Request No.:	**Date of Submission:**
006	August 24, 2021
PGE Direct Case:	**Date of Submission:**
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Blanket Projects	
PGE's Response to OPUC Data Request No.:	**Date of Submission:**
143	July 23, 2021
195	August 12, 2021
198 Revised	September 1, 2021
291	August 19, 2021
534	September 3, 2021
660	September 27, 2021
764	September 28, 2021
765	September 28, 2021
770	September 29, 2021
771	September 29, 2021
795	October 1, 2021
833	October 1, 2021
869	October 5, 2021
889	October 13, 2021
PGE's Response to AWEC Data Request No.:	**Date of Submission:**
233	October 19, 2021

Exhibit 2004 is voluminous in size and provided only in electronic format

Exhibit 2006 is highly confidential and is provided only in electronic format. Exhibit is subject to Modified Protective Order 21-237

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Load Forecast

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Amber Riter

December 2, 2021

Table of Contents

I. Introduction and Summary

Q. Please state your name and position with Portland General Electric Company (PGE).

A. My name is Amber M. Riter. I am an Economist and the Lead Load Forecasting Analyst at PGE. I am responsible for developing PGE's energy deliveries forecast. My qualifications appear in PGE's opening testimony, Exhibit PGE 1000.

Q. What is the purpose of your testimony?

A. There are two purposes of this testimony. First, to update the load forecast being used in this proceeding to reflect PGE's latest, September 2021, load forecast, consistent with that submitted in Docket UE-391 for PGE's 2022 Net Variable Power Cost. Second, to respond to load forecast recommendations provided by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) and the Alliance of Western Energy Consumers (AWEC) in their opening testimony.

Q. What load forecast recommendations were made in Staff's and AWEC's opening testimony?

A. OPUC Staff and AWEC recommend the removal of PGE's energy efficiency adjustment. AWEC also recommends modification to the COVID-19 indicator variable included in PGE's residential energy deliveries models and suggests upward revisions to the large customer forecast.

AWEC states that there are inconsistencies between the billing determinants shown in load forecasting data provided in the discovery process and pricing summary files, requesting reconciliation and supplemental workpapers be included in PGE's final compliance filing.

Q. Does PGE agree with these recommendations?

A. No. PGE does not agree with the basis for the suggested modifications. PGE's load forecast is used for many purposes outside of the GRC and must remain grounded in its intended reflection of a mid-point energy deliveries forecast. AWEC's modifications to the load forecast result in an increase of 775 Gigawatt hours (GWh)[1] to the test year energy deliveries forecast, increasing PGE's 2022 annual growth rate by 3.8%, from 2.1% to 5.9%. This recommended forecast is biased and does not reflect an 'expected' outcome for 2022. AWEC's large customer forecast recommendation reflects a policy-based outcome that is not supported by historical growth patterns or data and is unreasonable for establishing customer prices. Load increases in the context of how PGE plans for reliability is discussed further in PGE/2000.

Q. What is PGE's recommendation for the 2022 test year forecast?

A. PGE recommends the Commission adopt PGE's load forecast methodology and accept forecast updates consistent with the update schedule presented for the 2022 test year.

PGE's final load forecast for the 2022 test year will incorporate the most recent data available at the time of PGE's update in the first quarter of 2022, including continued assessment of residual impacts of COVID-19 on energy deliveries and best known economic and large customer information.

An updated load forecast is included in Section II of this reply testimony. The forecast update results in an increase of 156 GWh compared to PGE's initial 2022 test year energy deliveries forecast.

Q. How is your testimony organized?

[1] Estimated using workpaper provided with AWEC/200, Kaufman, AWEC Load Forecast Conf.xlsx Total adjustment of 775 GWh reflects 124 GWh due to removal of the energy efficiency adjustment, 209 GWh due to adjustment of the COVID-19 indicator variable and 442 GWh due to adjustment to the large customer forecast.

A. This testimony is organized into the following sections:

Section II: September Load Forecast Update

Section III: Energy Efficiency

Section IV: COVID-19

Section V: Large Customer Forecasts

Section VI: Billing Determinants

II. September Load Forecast Update

Q. What changes have been made to PGE's energy delivery models since the original filing?

A. The forecast models are largely unchanged from the March forecast. The regression models have been extended to include historical data through July 2021 and input assumptions have been updated to reflect the August forecast release from the Oregon Office of Economic Analysis. The large customer forecast has been updated to reflect the most recent historical data, trends and information provided by PGE's key customer managers in August of 2021.

Q. What changes have been made regarding the impact of COVID-19?

A. No changes were made in the COVID-19 related input assumptions impacting the 2022 test year. However, more rapid recovery in commercial energy deliveries in 2021 caused PGE to update its load forecast to reflect deterioration of the commercial COVID-19 indicator variable in 2021. Continued evidence of increased residential usage caused PGE to slow the rate of transition of the residential COVID-19 indicator variable from 100% in mid-2021 down to 30% in late 2021. These changes are reflected in Exhibit 2112.

Q. Please summarize PGE's updated energy deliveries forecast.

A. PGE's 2022 test year energy forecast is for energy deliveries of 20,653 GWh, on a cycle-month (billing) basis, including deliveries to customers who opted out of PGE cost-of-service rates for direct access under Schedules 485, 489 and 689. This reflects an increase of 156 GWh from the filed March forecast. This increase is driven primarily by changes to PGE's manufacturing sector energy deliveries forecasts.

Q. How does the 2022 forecast compare to recent historical demand?

A. Similar to the energy delivery trends of recent years, the 2022 forecast reflects strong growth in deliveries to industrial customers (primary and sub-transmission voltage service). Industrial deliveries growth is related to high-tech expansion and new data centers. The rate of growth in deliveries to industrial customers has increased in recent years following ongoing large high-tech construction projects. For Residential and Commercial classes, we expect the trends driving deliveries prior to 2020 will continue to influence the forecast in the long term as the COVID-19 impacts dissipate. However, 2022 growth rates reflect the continued unwinding of the impacts of COVID-19 on energy deliveries in 2021.

Table 1, below, summarizes the deliveries growth forecast by customer class on a weather adjusted, billing cycle basis from 2018 through 2022 including historical data through October of 2021.

Table 1: Annual Energy Deliveries Growth

	2018	**2019**	**2020**	**2021**	**2022**
Residential	0.8%	-2.0%	4.9%	1.4%	-3.8%
Commercial	0.4%	-1.4%	-6.8%	3.3%	3.0%
Industrial	1.1%	6.6%	6.5%	7.6%	9.7%
Total Retail	0.6%	0.1%	0.8%	3.6%	2.1%

For the residential class, usage increased significantly in 2020 reflecting increased time spent in the home because of the COVID-19 pandemic. The 2021 increase in residential energy deliveries reflects the higher, COVID-19 impacted, usage in the first quarter of 2021 compared to the pre-COVID usage in the first quarter of 2020. In 2022, we expect the reversal of most of the COVID-19 driven increases, with residential energy deliveries decreasing 3.8%.

The commercial (secondary voltage) energy deliveries also reflect the economic impacts of COVID-19. Energy deliveries decreased by 6.8% in 2020 and have rebounded significantly in 2021. The forecast for 2022 expects continued rebound following reopening of the economy and employment growth with usage growth of 3.0% in 2022.

Finally, industrial energy deliveries in PGE’s forecast continue to grow at a rapid pace. Ramping at new large customer facilities has increased the 2022 forecast to reflect 9.7% annual growth for this segment.

III. Energy Efficiency

Q. What recommendations are made with respect to the Energy Efficiency (EE) adjustment?

A. OPUC Staff and AWEC recommend that PGE's EE adjustment be eliminated, "now that PGE's historic data is limited to 2010, SB 1149 and SB 838 have equivalent levels of history embedded within the forecast. There is no longer a basis for an outboard EE adjustment."[2]

Q. What is the impact of Energy Efficiency on PGE's updated 2022 Test year forecast?

A. PGE's energy efficiency adjustment estimates incremental changes from the last historical period considered in the load forecast. The impact of EE on the 2022 forecast based on the September load forecast is 124.1 GWh, or 0.6%.

Q. Does PGE agree with recommendations made by Staff and AWEC?

A. No. PGE sees the recommended removal of the energy efficiency adjustment altogether as introducing increased risk of upward bias on the forecast.

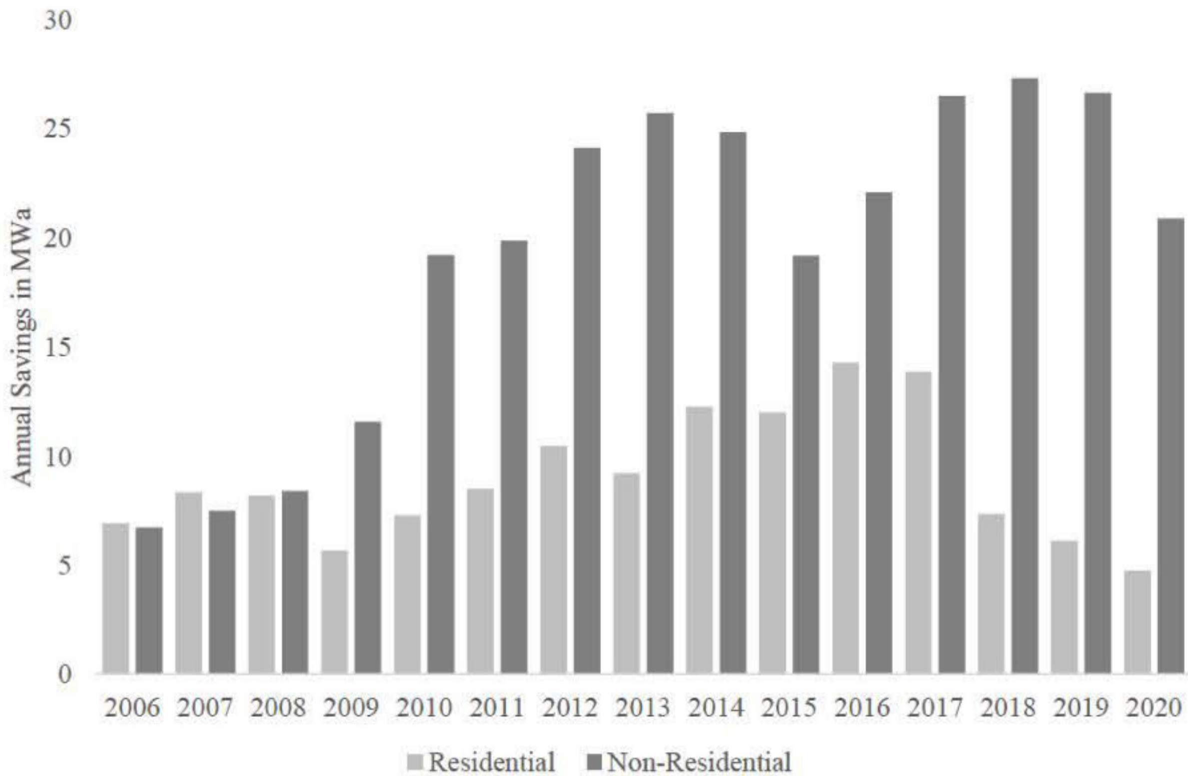
PGE's residential models largely include linear time trend variables. These trend variables capture long term decreases in average usage per customer where the distinct drivers for such trends are not easily quantified. The decreases represent a combination of factors that are not explicitly modeled, including energy efficiency as well as codes and standards, market driven changes in appliance and housing stock efficiency and behavioral changes. While this simplistic method is not able to account for the year-to-year volatility in the energy efficiency savings forecasts in the past, it may be a reasonable proxy as the savings have become more stable, depending on whether other underlying, particularly offsetting, influences are also stable.

[2] AWEC/200, Kaufman/6

The commercial models, on the other hand, do not include a time trend variable. Staff argues that "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."[3] While historic deliveries data does include embedded savings, no data is being fed into the model that would allow for it to capture this trend. The models are driven by economic, weather, and seasonal drivers alone. There is no variable capturing downward pressure on usage. As shown in Figure 1, in recent years, the savings achieved have been focused in the commercial and industrial customer segments. As such, PGE believes it is important to appropriately account for these savings and finds its current adjustment mechanism to be an appropriate way to make this adjustment. If the savings forecasts are not directly considered within the model, PGE is concerned that its deliveries forecast, specifically for non-residential customers, will be biased upward. Further, PGE does not believe it would be appropriate to recommend two different methods for handling energy efficiency in its models.

[3] Staff/900, Gibbens/10

Figure 1: Annual Energy Efficiency Savings in MWa



Q. What does PGE recommend?

A. PGE recommends continuation of its energy efficiency adjustment for the 2022 test year. While appreciating the concerns raised by parties, PGE does not believe the energy efficiency savings are captured in the current models for commercial customers, and a trend variable alone may not capture the nuanced end use trends impacting residential customers.

IV. COVID-19

Q. What recommendations are made with respect to how the impact of COVID-19 is estimated in the energy models?

A. Staff is generally supportive of PGE's approach to identify the impact of COVID-19 on loads but states that there is deficient evidentiary support for the long-term impact. Staff recommends continued updates, as the COVID-19 recovery continues to unfold, to ensure that the input assumptions in the forecast period are as accurate as possible.[4]

AWEC expresses concern with the long-term assumption noting "PGE's approach is not data-driven and does not constitute a known and measurable change"[5], and recommends that the residential forecast should reflect greater level of work-from-home, specifically that the COVID parameter should be adjusted from 30 percent to 75 percent for the 2022 test period. AWEC's recommendation raises PGE's September residential energy deliveries forecast by 205.7 GWh, reflecting a 2.7% increase in usage per customer.

Q. What is PGE's response to these recommendations?

A. PGE appreciates stakeholders' acknowledgement that recovery from the COVID-19 pandemic and the future of work-from-home has created additional uncertainty with respect to the energy deliveries forecast. PGE agrees that the future recovery from COVID-19 is not 'known and measurable'. While there is limited data available, as much is still unknown about the future path of the virus and residential customers behavioral response to it, PGE's approach has been to gather information from an array of different sources, including plans from regional employers and national trends, to develop an assumption based on informed

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[4] Staff/900, Gibbens/3
[5] AWEC/200, Kaufman/11

judgement. Consistent with Staff's reflection on the issue, PGE believes continued analysis, research and appropriate updates of input assumptions is the best way to manage this increased uncertainty.

Q. Does PGE agree with AWEC's recommendation to increase the residential COVID indicator variable to 75 percent?

A. No. PGE does not agree with the recommendation made by AWEC to increase the COVID-19 indicator variable to 75 percent. AWEC uses a single citation, based on the survey response of a specific segment, Tech executives, and applies that response to the entire service territory. The tech industry was known for a strong culture of work hour flexibility prior to COVID-19, making this a particularly poor point of reference, AWEC asserts that PGE's approach is not data-driven and then recommends a solution which is arbitrary and not data-driven.

Q. What additional evidence has PGE compiled with respect to the input assumption regarding residential usage?

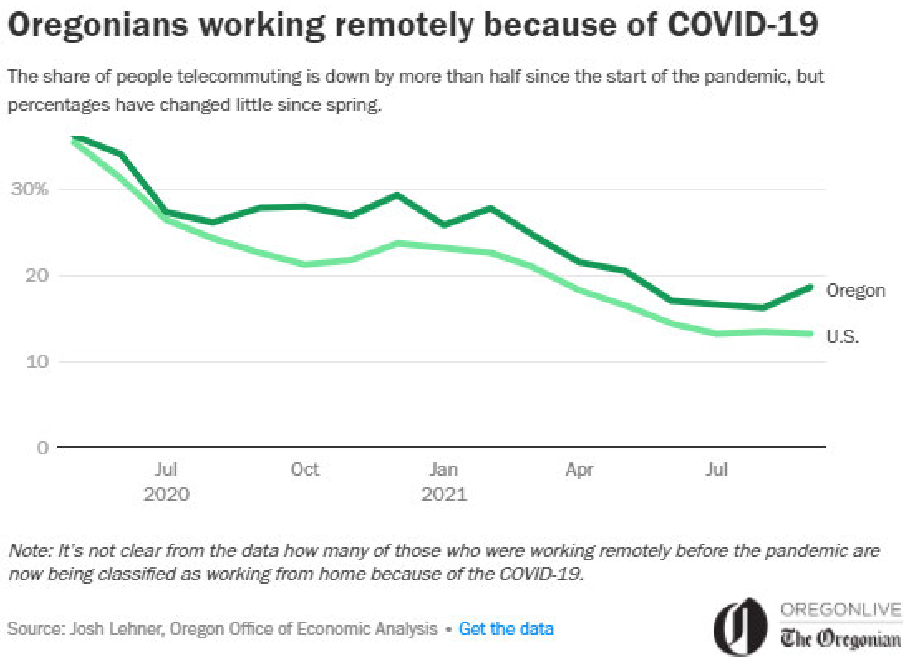
A. PGE has come across two data sources that it finds to be informative to its assumption for the residential COVID-19 indicator variable. Both provide evidence that use of an indicator variable of 75 percent for the 2022 test year is unreasonably high.

The first data set specifically looks at the percentage of workers who are working remotely due to COVID-19. This data set was recently compiled by the Oregon Office of Economic Analysis and cited in an Oregonian article[6] showing that the percentage of Oregonians working remotely due to COVID-19 has dropped from 36 percent in May of 2020 (the earliest the data series began) to 18 percent as of September of 2021, as seen in Figure 2.

[6] https://www.oregonlive.com/business/2021/11/oregonians-march-back-to-the-office-has-nearly-halted.html#:~:text=Similar%20trends%20are%20at%20play,13.2%25%20across%20the%20country).&text=Statewide%2C%20a%20little%20more%20than,the%20pandemic%2C%20according%20to%20Lehner.

This reflects a decrease of approximately 50 percent in 2021, reflecting that an impact of 75 percent is too high for 2022.

Figure 2: Share of Oregonians telecommuting due to COVID-19



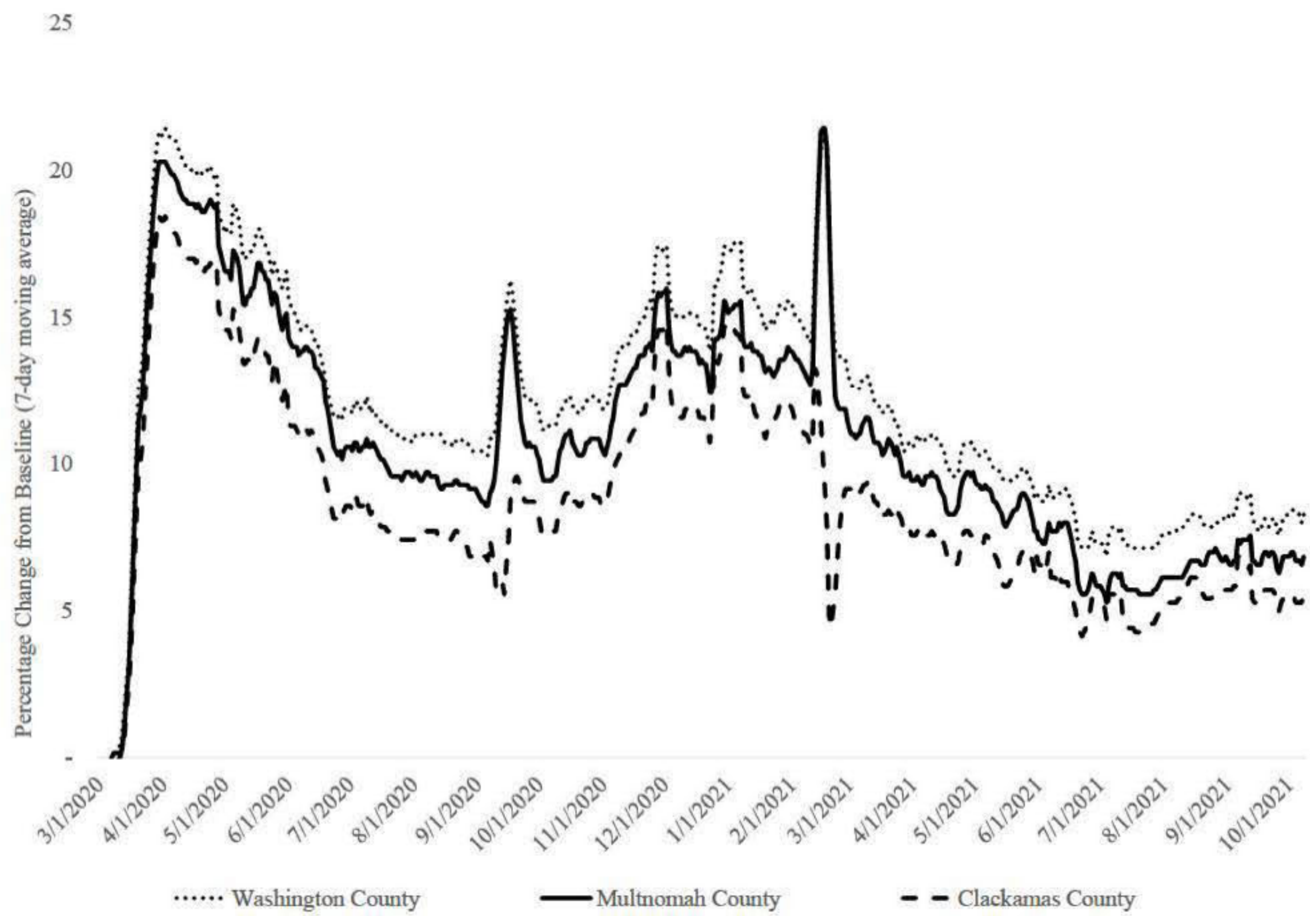
While we have largely discussed the path of the residential COVID-19 indicator as following trends in return to the office, the initial impact reflected behavioral changes across the residential class, not just for those who were able to make the transition to work from home (less than 40 percent in May 2020, as shown in Figure 2). In March 2020, unemployment spiked, schools and childcare facilities closed, and elective healthcare procedures were cancelled. The concern for transmission of the virus led to dramatic increases in time spent in the home.

Google's Community Mobility Report[7] reflects location data as compared to pre-pandemic baseline (defined as the median value from Jan 3-Feb 6, 2020) for a number of location subsets. Figure 3 reflects the residential set for the largest counties in PGE's service

[7] Google COVID-19 Community Mobility Reports (2021) https://www.google.com/covid19/mobility/

area. This data shows that the increase in residential activity has already dropped to about 50 percent of levels seen during the first year of the COVID-19 pandemic.

Figure 3: Google Community Mobility Data
Residential Percentage Change from Baseline



The impact on energy usage is additionally nuanced. For example, PGE is modeling seasonality and weather events separately, but those events are also impacting the mobility data based on the identified baseline period in the winter season. Additionally, there may be different impacts at a household level than an individual level. Perhaps only one member of the household is now at home versus two in 2020, but the increase in energy usage might be unchanged. Nevertheless, the impacts through Q3 of 2021 suggest that setting the indicator to 75 percent for 2022 would overstate the impact.

Q. Has PGE updated its assumptions with respect to the COVID-19 indicator variable in its latest forecast update for the 2022 test year?

A. No. PGE's September load forecast did not reflect any changes to COVID-19 indicator variables for 2022. PGE believes the 30 percent assumption is appropriate to reflect long-term work from home. However, the timing with respect to when that long-term normal is reached may be at risk. Recent news evidence points to likelihood of a wave of vaccine mandates and return to office in January for some of Oregon's largest employers including Nike.[8] However, it also appears mask mandates will continue into Spring 2022 in Oregon.[9] This may discourage additional return to the workplace for individuals who are able to effectively work from home. PGE continues to gather data to inform its input assumption and intends to update its forecast again in March of 2022 to reflect the best information available prior to final setting of rates.

[8] https://footwearnews.com/2021/business/athletic-outdoor/nike-vaccine-mandate-return-to-office-1203190902/
[9] https://www.pdxmonthly.com/news-and-city-life/2021/10/portland-oregon-mask-mandate-end

V. Large Customer Forecasts

Q. What does AWEC recommend with respect to PGE's large customer forecast?

A. AWEC "recommends forecasting Hillsboro large customer revenues using PGE's medium case 2020 (Transmission and Distribution) Planning Forecast."[10] AWEC asserts that differences in growth included in the load forecast and in the T&D forecast for Hillsboro are the result of one of two items, insufficient Minimum Load Agreements (MLAs), or PGE's failure to incorporate all expected load growth in the rate case deliveries forecast.[11]

Q. Does PGE agree with AWEC's assertions?

A. No. There are fundamental issues with AWEC's conclusions. PGE's T&D planning documents are not intended to capture ramping of facilities loading; rather, they reflect capacity needs provided by the customer. Reliability studies require in-depth engineering analysis of specific operational needs. These studies take time to develop, and action in response requires long lead times. This means that forecasts must be finalized well in advance of PGE's load forecast update cycle. Further, AWEC misstates the intent of the MLA. The MLA is intended to minimize risk associated with PGE's investments in T&D infrastructure to support increased customer loads.[12]

PGE's corporate load forecast is not performed at a locational level and not all customers are forecasted individually. The embedded nature of customer growth makes a direct comparison to the locational load evaluation needed for T&D facilities planning purposes problematic. While PGE understands that AWEC is requesting a specific level of growth be incorporated, to 'use PGE's planning forecast' is simply not reasonable. PGE's load forecast

[10] AWEC/200, Kaufman/2
[11] AWEC/200, Kaufman/17
[12] See PGE/2000 Bekkedahl-Jenkins/35

is intended to capture the best possible estimate of PGE's energy deliveries in the GRC test year (2022 for this GRC), and its intent should not be altered due to timing concerns associated with other planning items.

Further discussion on capital projects justifications, including how upgrades in the Hillsboro area benefit all customers, and how MLAs are used in PGE's planning process, is provided in PGE Exhibit 2000.

This testimony focuses on how PGE's load forecast is developed and the reasonableness of its results.

Q. What is PGE's load forecasting process for the customers included in PGE's large customer forecast?

A. For PGE's near-term energy deliveries model, which extends five years, PGE creates individual customer forecasts for a subset of its customers. These customers tend to be large or rapidly growing; however, smaller customers may be included based on legacy of historical loadings that fit these criteria. PGE's process for developing its large customer forecast is based on review of monthly historical data, quarterly meetings with PGE's key account managers (who regularly meet with customers), and assessment of risk associated with load ramping cadence and total anticipated energy usage and capacity needs. This risk assessment includes consideration of relevant MLAs and assessment of the financial risk associated with the specific customer.

Q. How has the onset of data center development in Hillsboro impacted this process?

A. The onset of data center development in Hillsboro has increased the pace and scale of large customer loads impacting PGE's forecast, which has increased the level of uncertainty embedded in PGE's forecast.

AWEC, using publicly available news sources, cites an array of new projects in PGE's Hillsboro service area totaling 'over 358 MW'[13]. While this information aligns with PGE's need for T&D upgrades in the area, it cannot be directly applied to forecasting the loading of these facilities in the 2022 test year. Customer plans may be on hold for many months and then materialize quickly to reflect contract finalizations. Multiple co-location data center facilities in PGE's service area may be competitors for the same contract. When a customer notifies PGE of future demand increases it is to ensure adequate facilities are available to meet their growth targets; it is not intended to be an annual projection of load used for ratemaking purposes.

The best information PGE has available to be used to estimate its load forecast is communication with the customer via PGE's key customer managers, prior, but still limited, experience with growth at similar facilities, and industry-based research. PGE's load forecasting team has used frequent updates to capture these changes as best as possible. PGE carefully tracks customer loads monthly and has also begun to track industry data, such as commercial market sector net absorption rates, to inform its decision making with respect to its large customer forecast.

Q. How have the customers in the New Load Direct Access (NLDA) queue been considered in PGE's load forecast?

A. PGE's load forecast considers NLDA customers no differently than any other customer. Energy deliveries for customers in the queue under the program cap are forecasted in the same manner described previously with the best information available at the time about the specific

[13] AWEC/200, Kaufman/19

facility loading. Remaining customers may still be on the queue if they have not had facilities come online or may be operating under PGE's other tariffs.

Q. Has PGE made updates to its large customer load forecast since its initial filing?

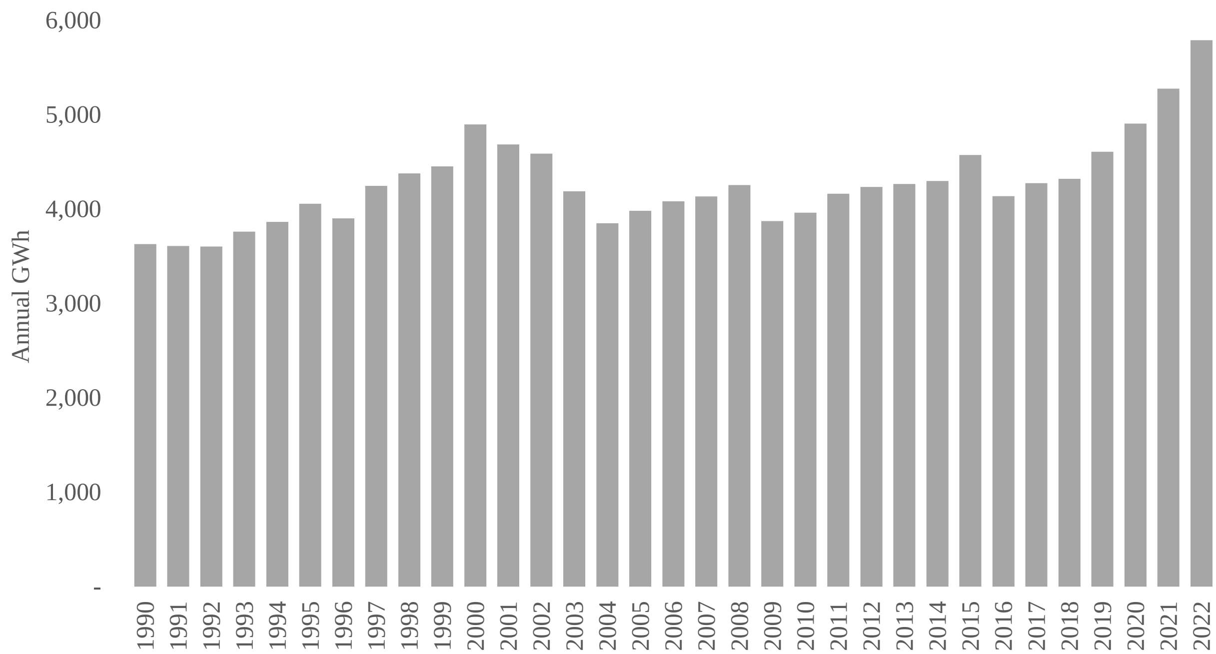
A. Yes. PGE has made updates to increase its large customer forecast between the March and September load forecasts as new information about ramp rates associated with large customer loads have become available. The update to the large customer forecast for 2022 increased PGE's energy deliveries forecast by 128.6 GWh.

Q. Why should the Commission be confident in PGE's forecast of its large customer loads?

A. PGE's latest load forecast incorporates the recent data updates from large customers and reflection of the most recent trends. The 2022 test year reflects industrial energy deliveries growth of 371 GWh as compared to 2021 and 884 GWh as compared to 2020. These load increases result in billing demand and facilities capacity values increases as shown in Confidential Table 2.

For context, this growth reflects the largest annual percentage increase in industrial loads seen since 2000, as shown in Figure 4, and largest increase in GWh since the 1970's.

Figure 4: PGE's Industrial Energy Deliveries



PGE's exhibits show the results of these updates, particularly Exhibit 2107 shows the Manufacturing NAICS segment forecasts and a High-Tech energy deliveries growth rate of 13.7 percent in 2022. This reflects significant acceleration, a 50 percent increase, from the average growth of 9 percent per year PGE has experienced over the last 5 years. PGE's Other Manufacturing segment also shows strong growth, 5.2 percent, reflecting upstream suppliers of PGE's High-Tech segment.

Confidential Table 2 shows the growth rates included in the September load forecast reflecting data in the format presented by AWEC in Confidential Table 4b[14] including demand-based billing determinants.

[14] PGE notes two Tables designated 'Confidential Table 4' and has renamed Table 4a (AWEC/200, Kaufman/23) and 4b (AWEC/200 Kaufman/24) for reference.

Confidential Table 2: PGE's September Load Forecast Billing Demand Growth Summary

[redacted]

Q. What does PGE request of the Commission with respect to PGE's forecast for large customer loads?

A. PGE requests that the Commission accept its approach to include large customer loads based on the best information available, with the intended outcome of a mid-point 'best estimate' energy deliveries forecast.

VI. Facility Capacity Billing Determinants

Q. What concerns does AWEC raise with respect to PGEs facility capacity estimates?

A. AWEC cites two inconsistencies. First, that the billing determinates used in PGE's rate design model do not match those estimated in its load forecast. Second, AWEC states that the facilities capacity values are not consistent with PGE's projected load growth.

Q. How does PGE explain the inconsistencies identified between PGE's rate design and load forecast model?

A. The inconsistencies were identified as a result of data provided in the discovery process and are largely a result of PGE's internal processes. PGE's load forecast process relies on historical data to create a set of ratios and factors that are used to estimate the billing determinant elements needed for the pricing model from its energy deliveries focused forecast. While this process involves rigorous review of historical data and corrections for historical anomalies, there are often items that are not corrected for until the forecast is uploaded into the pricing model.

When the pricing team takes the billing determinant output provided by load forecasting, it does an independent set of reviews including inspection of results by class, reconciliation of customer count and facilities capacity blocking, review of ratios for demand and facilities capacity as compared to historical data, and review for rate migration based on forecasted customer size. The file is 'tied-out' for energy (MWh) by service provider (COS/ESS) and voltage class. However, the process described above might create appropriate changes to PGE's load forecast output for demand and facilities capacity. This review by the pricing team ensures that the billing determinates used in the pricing model will correctly calculate the revenues PGE is proposing.

Ideally, these changes would be identified for analysis by the load forecasting team, creating a feedback loop to adjust its billing determinant estimates for the next iteration, which PGE improved upon for the September forecast.

Q. Has PGE's September forecast update corrected for identified inconsistencies?

A. Yes. PGE has identified several specific individual customer data issues in the load forecasting model that need to be edited to produce reasonable facilities capacity demand figures and has corrected its output for these items. While there are still some revisions made following the process described above by the pricing team, such as correction for rate migration between schedule 83 and 85, results of the feedback loop revisions made put the estimates into close alignment. Confidential Table 3 summarizes the two files in a consistent format to Confidential Table 4a provided by AWEC.

[redacted]

Q. Does PGE's September forecast correct for alignment with PGE's projected load growth? table

A. Yes. Confidential Table 2, shown on page 20, updates AWEC's work file to reflect a comparison of the values included in its pricing model to recent historical data. For 2021, PGE has compiled 10 months of actual data and two months of forecast to reflect MWh and billing demand, and the most recent 12 months ending October 2021 to reflect facilities capacity demand. The summary for 2022 reflects values consistent with PGE Exhibit 2200 and consistent growth across the billing determinants.

Q. How does PGE respond to AWEC's recommendation for additional workpapers?

A. PGE appreciates AWEC's recommendation with respect to development of workpapers that more clearly reflect consistency between the historical billing data, the load forecast and the rate design model. While PGE does not agree with the minimum requirements as defined in AWEC/100[15], PGE will include additional workpapers in its final compliance that show the ratios between MWh to demand to facilities capacity in the billing determinants are consistent with actual 2020 ratios.

Q. Does this conclude your testimony?

A. Yes.

[15] AWEC/200, Kaufman/25

List of Exhibits

Energy Deliveries Forecast (Base) by Market Segment and Service Level

(at average weather)

Base (not adjusted) Forecast [1]

	(in thousand MWh)					% Change [2]				
	2018	2019	2020	2021 [5]	2022	2018	2019	2020	2021	2022
Schedule 7	7,554	7,402	7,764	7,872	7,594	0.8%	-2.0%	4.9%	1.4%	-3.5%
Residential Lighting	2	2	2	2	2	-29.4%	-23.4%	-1.1%	-3.2%	-2.8%
Total Residential	7,557	7,404	7,765	7,874	7,596	0.8%	-2.0%	4.9%	1.4%	-3.5%
Commercial [3]	6,909	6,867	6,431	6,593	6,844	0.2%	-0.6%	-6.4%	2.5%	3.8%
Manufacturing [3]	4,718	4,956	5,198	5,622	6,197	1.0%	5.0%	4.9%	8.1%	10.2%
Miscellaneous Customers	160	141	135	154	140	2.8%	-11.6%	-4.5%	13.8%	-8.7%
Secondary Voltage	7,410	7,304	6,804	7,039	7,327	0.4%	-1.4%	-6.8%	3.4%	4.1%
Total General Service	7,465	7,356	6,856	7,088	7,373	0.2%	-1.5%	-6.8%	3.4%	4.0%
Primary Voltage Service	4,062	4,343	4,615	4,958	5,490	4.2%	6.9%	6.3%	7.4%	10.7%
Transmission Voltage Service	260	265	293	322	318	-31.2%	2.0%	10.5%	10.0%	-1.2%
Total Retail [4]	19,344	19,368	19,529	20,242	20,777	0.6%	0.1%	0.8%	3.6%	2.6%

1 SEP21B_W75

2 Calculated from rounded numbers

3 By NAICS grouping

4 Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

5 Weather adjusted actual through October 2021

Energy Deliveries Forecast (Energy Efficiency Adjusted) by Market Segment and Service Level

(at average weather)

Net of Incremental Energy Efficiency [1]

	(in thousand MWh)					% Change [2]				
	2018	2019	2020	2021 [5]	2022	2018	2019	2020	2021	2022
Schedule 7	7,554	7,402	7,764	7,870	7,569	0.8%	-2.0%	4.9%	1.4%	-3.8%
Residential Lighting	2	2	2	2	2	-29.4%	-23.4%	-1.1%	-0.6%	-1.1%
Total Residential	7,557	7,404	7,765	7,871.6	7,571	0.8%	-2.0%	4.9%	1.4%	-3.8%
Commercial [3]	6,909	6,867	6,431	6,588	6,789	0.2%	-0.6%	-6.4%	2.4%	3.0%
Manufacturing [3]	4,718	4,956	5,198	5,618	6,153	1.0%	5.0%	4.9%	8.1%	9.5%
Miscellaneous Customers	160	141	135	154	140	2.8%	-11.6%	-4.5%	13.8%	-8.7%
Secondary Voltage	7,410	7,304	6,804	7,031	7,244	0.4%	-1.4%	-6.8%	3.3%	3.0%
Total General Service	7,465	7,356	6,856	7,080	7,290	0.2%	-1.5%	-6.8%	3.3%	3.0%
Primary Voltage Service	4,062	4,343	4,615	4,957	5,474	4.2%	6.9%	6.3%	7.4%	10.4%
Transmission Voltage Service	260	265	293	322	318	-31.2%	2.0%	10.5%	10.0%	-1.2%
Total Retail [4]	19,344	19,368	19,529	20,231	20,653	0.6%	0.1%	0.8%	3.6%	2.1%

1 SSEP21E_W75

2 Calculated from rounded numbers

3 By NAICS grouping

4 Total Retail equals Total Residential + Commercial + Manufacturing + Miscellaneous. Also equals Total Residential + Total General + Primary Voltage Service + Transmission Service, totals may not foot due to rounding.

5 Weather adjusted actual through October 2021

Forecast of Incremental Energy Efficiency (EE) Savings

(in thousand MWh)

	2021	2022
Base (B) Forecast	20,242	20,777
Incremental EE Savings [1]	(11)	(124)
Post-EE Forecast (E) [2]	20,231	20,653

1 Energy Trust of Oregon (ETO) annual savings deployment forecast.

2 Totals and differences may not foot due to rounding.

Residential Building Permits, New Connects, Vacancy Rates and Customer Counts History and Forecast

	2018	2019	2020	2021 [1]	2022
Building Permits [2]					
Single-Family	10,333	10,087	10,480	10,060	11,108
Multi-Family	9,096	10,756	6,932	8,016	9,592
New Connects					
Single-Family	4,902	4,908	4,531	4,851	4,769
Multi-Family	6,163	5,430	6,085	4,581	4,538
Mobile Home	115	123	121	96	120
Other	175	233	262	199	180
Total Residential Connects	11,355	10,694	10,999	9,727	9,607
Commercial Connects	2,785	2,619	2,300	2,452	2,491
Total New Connects	14,140	13,313	13,299	12,179	12,098
Residential Customer Counts					
Single-Family Heat	114,390	116,928	119,127	124,148	126,179
Single-Family Non-Heat	367,333	368,674	371,545	370,175	372,255
Multiple-Family Heat	192,248	197,323	203,820	211,092	214,552
Multiple-Family Non-Heat	61,042	60,172	59,723	57,659	58,091
Mobile Home Heat	30,738	30,655	30,712	30,721	30,652
Mobile Home Non-Heat	4,099	4,170	4,199	4,195	4,193
Other	2,625	1,750	2,028	2,228	2,322
Total Number of Accounts [3]	772,423	779,673	791,154	800,218	808,244

1) Includes actuals through Septeber 2021, except for connects which include actuals through June 2021

2) Oregon building permits

3) Includes vacant accounts

Forecast of Residential Use per Customer and Ultimate Deliveries

(at average weather)

Net of Incremental Energy Efficiency

Use per Customer (kWh)	2018	2019	2020	2021 [1]	2022
Single-Family Heat	14,169	13,622	13,993	13,950	13,422
Single-Family Non-Heat	9,746	9,564	9,982	9,981	9,444
Multiple-Family Heat	7,821	7,469	7,643	7,657	7,283
Multiple-Family Non-Heat	5,880	5,732	5,958	5,983	5,718
Mobile Home Heat	13,670	13,260	13,391	13,495	13,247
Mobile Home Non-Heat	10,765	10,703	10,918	11,022	10,654
Other	10,175	7,429	8,392	8,352	6,394
Average Use per Customer	9,783	9,496	9,815	9,835	9,365
Ultimate Deliveries (millions of kWh)					
Single-Family Heat	1,621	1,593	1,667	1,732	1,694
Single-Family Non-Heat	3,580	3,526	3,709	3,695	3,515
Multiple-Family Heat	1,504	1,474	1,558	1,616	1,563
Multiple-Family Non-Heat	359	345	356	348	332
Mobile Home Heat	420	406	411	415	406
Mobile Home Non-Heat	44	45	46	46	45
Other	27	13	17	19	15
Schedule 7 Deliveries	7,555	7,402	7,764	7,870	7,569
Residential Lighting	2	2	2	2	2
Total Residential Deliveries	7,557	7,404	7,766	7,872	7,571

1 Weather adjusted actual through October 2021

Commercial Energy Deliveries Forecast by NAICS Sector

(at average weather)

Net of Incremental Energy Efficiency

						% Change [1]				
	2018	2019	2020	2021 [2]	2022	2018	2019	2020	2021	2022
Food Stores	415	397	371	360	367	-1.5%	-4.3%	-6.6%	-2.8%	2.0%
Govt. & Education	983	963	843	894	949	-0.1%	-2.0%	-12.4%	6.0%	6.2%
Health Services	715	730	708	705	718	-0.5%	2.1%	-3.0%	-0.5%	1.8%
Lodging	107	104	87	95	99	0.9%	-2.9%	-16.4%	8.8%	4.8%
Misc. Commercial	634	582	609	657	594	-11.0%	-8.2%	4.7%	7.8%	-9.6%
Department Stores/Malls	316	302	283	284	305	-5.0%	-4.4%	-6.3%	0.5%	7.1%
Office & F.I.R.E. [3]	1,068	1,118	1,050	1,058	1,106	12.0%	4.6%	-6.1%	0.8%	4.5%
Other Services	847	857	771	796	850	0.2%	1.3%	-10.1%	3.3%	6.8%
Other Trade	724	725	700	713	718	1.4%	0.2%	-3.5%	1.9%	0.7%
Restaurants	475	465	393	402	462	-1.1%	-2.2%	-15.5%	2.3%	14.8%
Trans., Comm. & Utility	627	624	616	624	621	-0.4%	-0.4%	-1.2%	1.2%	-0.4%
Total Commercial	6,909	6,867	6,431	6,588	6,789	0.2%	-0.6%	-6.4%	2.4%	3.0%

1 Calculated using rounded-numbers

2 Weather adjusted actual through October 2021

3 Finance, Insurance, and Real Estate

Manufacturing Deliveries Forecast by NAICS Sector

(at average weather)

Net of Incremental Energy Efficiency

						% Change [1]				
	2018	2019	2020	2021 [2]	2022	2018	2019	2020	2021	2022
Food & Kindred Products	273	274	275	270	260	2.0%	0.1%	0.4%	-1.8%	-3.5%
High Tech	2,771	3,008	3,343	3,714	4,221	6.0%	8.5%	11.1%	11.1%	13.7%
Lumber & Wood	101	96	88	95	90	0.4%	-5.5%	-8.2%	7.9%	-4.9%
Metal Manufacturing and Fab	445	445	388	386	388	-0.1%	0.0%	-12.9%	-0.5%	0.4%
Other Manufacturing	780	778	731	770	810	1.6%	-0.2%	-6.1%	5.4%	5.2%
Paper Manufacturing	174	180	218	236	229	-41.2%	3.2%	21.3%	8.0%	-2.7%
Transportation Equipment	173	176	156	148	155	-2.7%	1.5%	-11.0%	-5.4%	4.8%
Total Manufacturing	4,718	4,956	5,198	5,618	6,153	1.0%	5.0%	4.9%	8.1%	9.5%

1 Calculated using rounded-numbers

2 Weather adjusted actual through October 2021

Forecast of Energy Deliveries to Miscellaneous Rate Schedules

Net of Incremental Energy Efficiency

	(in thousand MWh)					% Change [1]				
	2018	2019	2020	2021 [2]	2022 [2]	2018	2019	2020	2021	2022
Residential										
Outdoor Area Lighting (15R) [3]	2	2	2	2	2	-29.4%	-22.9%	-1.7%	-3.2%	-2.8%
Secondary (Commercial)										
Outdoor Area Lighting (15C) [4]	14	14	13	12	12	5.0%	1.0%	-4.0%	-5.7%	-0.9%
Farm Irrigation et al. [5]	91	76	70	92	82	15.0%	-16.8%	-7.7%	31.5%	-11.4%
Street and Other Lighting [6]	55	52	52	49	46	-12.9%	-6.1%	0.1%	-5.0%	-5.7%
Total Miscellaneous Commercial	160	141	135	154	140	2.8%	-11.6%	-4.5%	13.8%	-8.7%
All Miscellaneous Schedules [7]	162	143	137	155	142	2.1%	-11.8%	-4.4%	13.6%	-8.7%

1 Calculated from rounded numbers

2 Identical for non-price, price-effect and post-EE forecasts

3 Existing Schedule 15R

4 Existing Schedule 15C

5 Existing Schedules 47 & 49

6 Existing Schedules 91, 92 & 93, and Schedule 95 beginning in 2013. Rate schedule 93 moved to Rate Schedule 38 in 2014.

7 Equals line 2 + line 7

Total Delivery and Demand Forecast

Net of Incremental Energy Efficiency [4]

	Million kWh [1]	Average MW [2]	Peak MW [3]
2013	19,265	2,346	3,869
2014	19,420	2,329	3,866
2015	19,344	2,344	3,914
2016	19,368	2,287	3,726
2017	19,529	2,389	3,976
2018	19,398	2,322	3,816
2019	19,367	2,343	3,765
2020	19,529	2,348	3,771
2021	20,231	2,465	4,441
2022	20,653	2,502	3,928

1 Cycle-month basis, at end-user meters, weather adjusted; includes actual deliveries through October 2021

2 Calendar basis, at the bus bar, actual through October 2021, not adjusted for weather.

3 Coincident annual system peak at bus bar; includes actual through Oct 2021, not adjusted for weather.

4 Forecast reflects the 'E' forecast.

Forecast of 2022 Deliveries to Cost of Service and Direct Access Customers

Net of Incremental Energy Efficiency

(in thousand MWh)

	Cost of Service [1]	Direct Access [2]	Total Delivery [3]
Residential	7,571	0	7,571
Secondary	6,750	493	7,244
Primary	4,037	1,437	5,474
Transmission	52	267	318
Lighting	47	0	47
Total Retail [3]	18,456	2,197	20,653

1 Includes economic replacement VPO deliveries

2 Schedule 485/489/689 deliveries

3 Totals may not add due to rounding.

Degree Day Variables

	2021		2022	
	HDD65	CDD65	HDD65	CDD65
January	648.0	0.0	761.5	0.0
February	673.3	0.0	647.6	0.0
March	579.0	0.0	545.1	0.0
April	411.0	0.0	394.9	0.4
May	201.6	4.0	239.5	12.3
June	108.8	83.1	112.4	43.5
July	10.1	263.7	37.5	139.1
August	1.0	292.6	9.5	218.8
September	16.0	157.3	26.1	163.2
October	168.5	37.3	133.6	32.1
November	365.5	0.3	364.2	0.3
December	665.1	0.0	664.3	0.0
Annual	3,847.8	838.3	3,936.2	609.7

Cycle Weighted COVID-19 Variables

		Residential	Non-Residential	
Year	Month	Variable 1	Phase 1	Phase 2
2020	1	0.0	0.0	0.0
2020	2	0.0	0.0	0.0
2020	3	0.2	0.1	0.2
2020	4	0.9	0.8	0.2
2020	5	1.0	1.0	0.0
2020	6	1.0	0.9	0.1
2020	7	1.0	0.2	0.8
2020	8	1.0	0.0	1.0
2020	9	1.0	0.0	1.0
2020	10	1.0	0.0	1.0
2020	11	1.0	0.0	1.0
2020	12	1.0	0.0	1.0
2021	1	1.0	0.0	1.0
2021	2	1.0	0.0	0.9
2021	3	1.0	0.0	0.6
2021	4	1.0	0.0	0.6
2021	5	1.0	0.0	0.8
2021	6	1.0	0.0	0.5
2021	7	1.0	0.0	0.1
2021	8	1.0	0.0	0.0
2021	9	0.9	0.0	0.0
2021	10	0.7	0.0	0.0
2021	11	0.5	0.0	0.0
2021	12	0.4	0.0	0.0
2022	1	0.3	0.0	0.0
2022	2	0.3	0.0	0.0
2022	3	0.3	0.0	0.0
2022	4	0.3	0.0	0.0
2022	5	0.3	0.0	0.0
2022	6	0.3	0.0	0.0
2022	7	0.3	0.0	0.0
2022	8	0.3	0.0	0.0
2022	9	0.3	0.0	0.0
2022	10	0.3	0.0	0.0
2022	11	0.3	0.0	0.0
2022	12	0.3	0.0	0.0

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 394

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony of

Robert Macfarlane
Teresa Tang

December 2, 2021

Table of Contents

I. Introduction

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

A. My name is Robert Macfarlane. I am Manager of Pricing and Tariffs for PGE.

My name is Teresa Tang. I am a Regulatory Consultant in Pricing and Tariffs for PGE.

Our qualifications were previously provided in PGE Exhibit 1200.

Q. What is the purpose of this reply testimony?

A. We provide an update of the overall rate impacts and the impacts to various PGE rate schedules consistent with the testimony in PGE Exhibit 1400. We also address the following issues raised by the Public Utility Commission of Oregon (OPUC or Commission) Staff (Staff) in Staff Exhibits 400 and 1400, the Alliance of Western Energy Consumers (AWEC) in AWEC Exhibit 100, and the Citizen's Utility Board of Oregon (CUB) in CUB Exhibit 100, Calpine Energy Solutions, LLC (Calpine Solutions) in Calpine Solutions Exhibit 100, Fred Meyer Stores and Quality Food Centers, divisions of The Kroger Co. (Fred Meyer) in FM Exhibit 100, and Walmart Inc. (Walmart) in Walmart Exhibit 100:

- Marginal Cost Study
- Generation Demand Charge
- Customer Impact offset
- Nonbypassability of various program costs
- Residential Multi-family Basic Charge
- Subtransmission rate for Schedule 90
- Service charges and other schedules; and
- Decoupling 2% limiter.

Q. Has PGE agreed with parties on any issues raised in parties' opening testimonies?

A. PGE has agreed with parties on the following issues:

- The decoupling mechanism will not expand to Schedule 47 and 49;
- To evaluate energy battery storage in Schedule 75/76R, a new large load Cost of Service (COS) schedule, and how fee free bank card costs are allocated; and
- To update the gas price in the generation marginal cost study using the most recent forecast.

Q. Please summarize the updated projected 2022 Cost of Service rate impacts.

A. Table 1, below, summarizes the base rate impacts effective May 9, 2022 for the major rate schedules.

Table 1
Estimated Cost of Service Base Rate Impacts Inclusive of Schedules 122, and 125, and 146.[1]

Schedule	Base Rates
Schedule 7 Residential	8.4%
Schedule 32 Small Nonresidential	10.4%
Schedule 83 31-200 kW	7.0%
Schedule 85 201-4,000 kW	0.8%
Schedule 89 Over 4,000 kW	0.8%
Schedule 90 100 MWa	-1.8%
COS & DA Overall	5.7%

[1] This represents the increase on a cycle basis. Without the Customer Impact Offset (CIO), impacts for Schedules 7, 32, 85 and 89 are 8.4%, 12.6%, 0.1% and -0.7% respectively.

II. Marginal Cost Studies

Q. In Staff/1400, Staff witness Dr. Max St. Brown discusses the need to adjust future generation marginal costs studies in consideration of HB 2021, the clean energy bill. In AWEC/100, Dr. Kaufman proposes that PGE change its generation marginal cost study in this case to remove the capacity value of wind when calculating energy costs and include the capacity of pumped hydro for capacity costs. Please discuss your thoughts on modifying the generation marginal cost study in light of HB 2021.

A. The new legislation[2] was signed into law around the time PGE filed this case. It passed the Oregon House and Senate in late June, within days of PGE filing this case. PGE begins its marginal cost studies months prior to filing a general rate case and finalizes those studies more than a month before filing. It's not reasonable to presume PGE could have evaluated the legislation and proposed revisions to its marginal cost study in a matter of days as PGE filed this case in early July.

Q. Is PGE prepared to revise its generation marginal cost study in light of HB 2021 for this case?

A. No. PGE has not developed the materials to provide a revised generation marginal cost study for this case. It needs to identify the appropriate capacity resources and how to evaluate them, how to divide up the benefits of each resource, and how to mitigate impacts on residential and small nonresidential customers, as Staff indicates.

Q. What dockets will address issues around clean energy and capacity?

[2] https://katu.com/news/local/oregon-governor-signs-ambitious-clean-energy-bill, signed July 19, 2021

A. UM 2011, General Capacity Investigation, will also address clean energy and capacity issues. In addition, PGE's next Integrated Resource Plan (IRP) will address many issues raised by HB 2021 and the Commission will have a process to address the implementation of HB 2021.

Q. Does the development of PGE's marginal cost study use its IRP to develop analyses? Is PGE's next IRP delayed?

A. The analyses included in PGE's IRP are the primary sources of generation marginal cost studies. The Commission approved PGE's request for waiver of OAR 860-027-0400(3) at its November 16, 2021 public meeting to delay PGE's next IRP until March 2023.

Q. Was HB 2021 one of the reasons for the delay?

A. Yes. PGE proposed to delay the next IRP for several reasons including the development of newly enacted planning requirements established in HB 2021, to coordinate with stakeholders and Staff on an IRP Action Plan to meet changing system needs and address HB 2021's decarbonization targets, to incorporate HB 2021's Clean Energy Plan and Utility Community Benefits and Impacts Advisory Group Report into the IRP as one holistic document, among other reasons.

Q. Is there potential that UM 2011 also impacts development of PGE's generation marginal cost study?

A. Yes. The docket may provide a best practice to value capacity contributions from various resources.

Q. If PGE were to develop a generation marginal cost study at this time, would the outcome likely shift impacts among customer classes?

A. Yes, although we don't yet have enough data and analysis to adequately value capacity from non-emitting resources and identify energy, flexible load, and other benefits. Taking a more simplistic approach that doesn't value those benefits would shift costs to residential and small business customers. In the next general rate case, after PGE's next IRP and more thorough analysis is completed, another shift would likely occur.

Q. What is your recommendation?

A. We recommend using the marginal cost study as filed for this general rate case. Once PGE completes its next IRP and more analysis is complete, PGE can include revisions in a future general rate case to develop a comprehensive and informed generation marginal cost study, that would then identify the energy, capacity, and flexibility values, as well as other benefits to assign to the various customer classes.

Q. AWEC also recommends removing the capacity value of wind in the generation marginal cost study. How do you respond?

A. PGE's inclusion of wind in its generation marginal cost study dates back to six previous general rate cases. In all of those cases, wind has been included at its full value in the marginal cost of energy. The capacity value of wind varies with the amount of wind and other renewables on PGE's system. Given the unpredictability of the wind blowing, it's safe to say that wind provides mostly energy. PGE's generation marginal cost study is a simplified study to allocate costs and is not meant to replicate PGE's entire generation fleet.

Q. Staff makes several additional proposed changes to the generation marginal cost study including: reducing the reserve margin from 12 to 10 percent, netting out energy sales to reduce the cost of capacity and incorporating higher natural gas prices. How do you respond?

A. Staff did not justify the change to the reserve margin. As filed, the 12% reserve margin is consistent with PGE's last IRP. It's also consistent with planning and operational standards that allow PGE to provide resource adequacy and system reliability. The netting out of energy sales is another example of adding unnecessary complexity to the study and has the effect of counteracting AWEC's recommendation to remove wind capacity. Staff's suggestion to incorporate higher natural gas prices has merit, as natural gas prices have changed dramatically since PGE filed its case.

Q. What is PGE's overall response related to the proposed changes to its generation marginal cost study as filed?

A. PGE is agreeable to updating the gas price forecast in its generation marginal cost study using the most recent forecast. PGE will also update the cost of debt to be consistent with the first stipulation in this docket.

Q. Please discuss AWEC's proposal to add $44 million in other customer costs to Customer Marginal Cost model.

A. AWEC argued that PGE failed to update the Company's Customer Marginal Cost study based on PGE's updated unbundling methodology and proposed to add $44 million in other customer costs to the Customer Marginal Cost model. AWEC provides their modifications in Exhibit 205. AWEC noted that PGE is allocating the cost for Customer Contact Operations correctly in FERC account 9050001 but that PGE does not allocate the cost for Customer Contact Operations that are part of FERC account 9030001.

Q. Does PGE agree with this proposal?

A. No. First, PGE does allocate the costs for Customer Contact Operations that are charged to FERC account 9030001. The costs are allocated in the same manner as the Customer Contact Operations costs charged to FERC account 9050001, however, they are part of the Billing costs. Secondly, AWEC Exhibit 205 adds non-direct costs to the Marginal Customer Cost such as Resource Center 881 Government Affairs. The Customer Marginal Cost model is based on allocating direct costs to customers; indirect costs like those incurred by the Government Affairs department do not belong in the Customer Marginal Cost study.

III. Generation Demand Charge

Q. What is the recommendation from Parties in regard to generation demand charges?

A. Staff and Walmart recommend PGE introduce on-peak generation demand charges for Schedules 83 and 85 customers. Staff opposes PGE's proposal to consider on-peak generation demand charges until after the resource adequacy (RA) issues are addressed in Docket UM 2143. Staff states that on-peak generation will create an appropriate incentive for customers to manage their peak loads and reduce system capacity requirements during peak time.

Walmart argues that all the fixed generation costs incurred to service Schedules 83 and 85 customers are recovered through the energy charge, which violates cost causation principles in rate design. Additionally, Walmart argues that the fixed generation cost should be collected through a generation demand charge; stating that without a generation demand charge, a customer with higher load factor will overpay demand-related costs by paying for a portion of the demand-related costs to serve the lower load factor customers. Walmart further proposes 25 percent of the fixed generation cost as the basis for the generation demand charge. Walmart does not oppose the current on-peak/off-peak price differential of 1.5 cents/kWh.

Q. How does PGE respond to the on-peak generation demand charge proposal by parties?

A. PGE finds that both Staff and Walmart have valid points regarding on-peak generation demand charges. However, it is more appropriate to consider on-peak generation demand charges after resource adequacy is addressed in Docket UM 2143.

Q. Why is it more appropriate to consider on peak generation demand charges after resource adequacy is addressed in UM 2143?

A. As PGE stated in Exhibit 1200, proposing a new on-peak demand charge would create complexity and future alignment challenges when resource adequacy is addressed by the

Commission. PGE is committed to provide safe and reliable service for all customers as the provider of last resource (POLR) for all load on the system. While doing so, PGE must acquire sufficient resource capacity to service loads under any conditions, the costs of which are included in the generation revenue requirement. As long term direct access (LTDA) loads opt out of the system, the share of reliability burden would fall to all COS customers. An on-peak generation demand charge would incentivize customers to use less energy during the on-peak period. However, for the customers whose usage is less flexible, one of their options is to opt out from COS and use electricity service from an Electricity Supply Service (ESS). By doing so, the customer and ESS can avoid contributing to resource adequacy, inherent in the generation demand charge, and continue to benefit from the reliability PGE provides without contributing to the costs of reliability. As a result, pricing disparity widens, and COS customers bear more burden of paying for the reliability service.

Q. How do you respond to Staff's comment that "the recovery of 100% fixed cost through an energy charge violates several pricing principles"?

A. PGE does not agree with this comment. The pricing design strikes a reasonable and appropriate balance among all pricing principles. For example, the residential basic charge is designed to cover fixed costs, however a substantial amount of fixed costs is recovered through a volumetric charge in the residential rate. PGE maintains the balance among pricing elasticity, revenue requirement recovery, and fairness among COS and DA customers in the Schedule 83 and Schedule 85 rate design.

Q. Please elaborate.

A. If Schedule 83 and Schedule 85 customers' price elasticity is higher than 1, which means they are able to increase the load factor and move the energy consumption off peak time, and an on-peak generation demand charge provides an effective price signal. While the customers move the energy consumption away from the peak time, there will be less demand (kW) to spread the fixed generation cost over, which demand charge will end up increasing up to a point that the pricing elasticity becomes very close to 1. However, base rates only change during general rate cases. Until the next general rate case, PGE will be under recovering its full generation fixed cost.

While price elasticity approaches 1 or less than 1, the price signal is not effective since it is not able to change customer behavior. When a customer is not able to move energy around peak hours and if the customer opts out the system, this will cause unfairness of reliability cost recovery for remaining COS customers.

Q. What is the status of current RA docket, UM 2143?

A. On October 15, 2021, Staff proposed a docket strategy and straw proposal for the UM 2143 docket including both an interim solution and long-term solutions to RA. In addition, PGE is actively participating in the Northwest Power Pool (NWPP) RA effort and fully supports the straw proposals. PGE will continue to investigate RA and the relationships to on-peak generation demand charges.

IV. Customer Impact Offset

Q. What is the Customer Impact Offset (CIO)?

A. The Customer Impact Offset (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[3].

Q. How did PGE use the CIO to adjust rates in this rate case?

A. The main adjustment PGE made is to limit the rate impact to Schedule 7 and Schedule 32 customers by decreasing the distribution charges for these schedules and increasing the system usage charges for Schedule 85 and 89, along with their direct access equivalents. The following table details the rate impact from CIO by PGE and different parties:

Table 2
Estimated Cost of Service Base Rate Impacts Inclusive of Schedules 122, and 125, and 146 by Parties

Schedule	Without CIO	PGE's CIO	Staff's CIO	AWEC's CIO	Fred Meyer's CIO
Schedule 7 Residential	6.90%	6.40%	5.80%	6.90%	6.60%
Schedule 32 Small Nonresidential	9.70%	7.80%	7.80%	9.70%	7.80%
Schedule 83 31-200 kW	4.40%	4.40%	4.90%	4.40%	4.40%
Schedule 85 201-4,000 kW	-1.80%	0.00%	0.10%	-1.80%	-0.10%
Schedule 89 Over 4,000 kW	-1.90%	0.00%	0.60%	-1.90%	0.00%
Schedule 90 30 MWa	-3.20%	-3.20%	0.00%	-3.20%	-3.20%
Schedule 485 201-4000 kW *		15.60%	15.60%	15.60%	6.50%
COS & DA Overall	3.90%	3.90%	3.90%	3.90%	3.90%

**: PGE does not agree with the calculation of Schedule 485 rate impact. It is directly from Fred Meyer Table JB-3.*

[3] Order No. 14-422. p.11

Q. How does PGE respond to each proposed adjustment to the CIO?

A. PGE does not agree with Staff's argument that one schedule should not have a rate decrease when the overall case presents a rate increase. In Docket UE 262 the Commission approved PGE reducing Schedule 89 rates by 1.2% while increasing all the other customer classes[4].

PGE does not agree with Walmart since the adjustment only benefits Schedule 85 and Schedule 485 customers. Walmart gives no reasons why Schedule 85 and Schedule 485 should receive a favorable treatment compared to other large customers (Schedule 89, 489 and 90).

PGE does not agree with AWEC's proposal to remove the CIO completely because it doesn't provide enough price impact mitigation to small customers.

PGE recommends the Commission to approve the CIO as proposed in this case since it provides a balanced price impact among all customer classes and supports several rate design principles. Without CIO, the small customers (Schedule 32) will see a close to double digit price increase; and large customers (Schedule 85 and 89) prices will see a price decrease. Lowering the small customer price increase and keeping the large customer price impact flat is a reasonable balancing of impacts.

Q. Are rate impacts only determined in GRC?

A. No. Customer prices change with Annual Update Tariff (AUT) updated pricing, and supplemental schedules' rates that are effective outside the GRC process.

Q. Why does PGE think that Schedule 90 price decreases is appropriate while other schedules expect price increases in this general rate case?

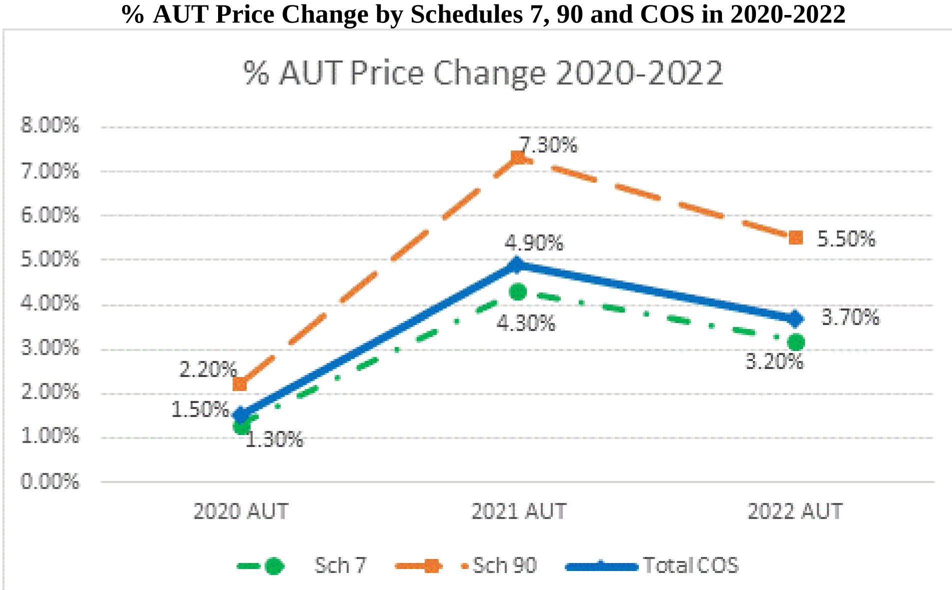
[4] Order No. 13-459s

A. Schedule 90 customers have experience higher than average price increases from the past few AUTs comparing to other schedules. Schedule 90 loads are stable, with long term growth and a high load factor energy consumption pattern, which provides a unique contribution to the entire system. All customers benefit from Schedule 90 customers remaining on COS as it provides the additional kWh over which PGE spreads its costs, resulting in lower prices for all customers.

Q. How much have Schedule 90 prices increased since the last general rate case (UE 335)?

A. Table 3 below shows Schedule 7, Schedule 90, and total COS price increases since PGE's last general rate case (UE 335). Schedule 90 increase is higher than the total COS price increase and Schedule 7 price increase is lower than the COS price increases in the past three years. The higher-than-average increase in Schedule 90 implies that the AUT price changes disproportionally impact this schedule since price increase from AUT mostly comes from energy related charges.

Table 3
% AUT Price Change by Schedules 7, 90 and COS in 2020-2022



V. Nonbypassability Charges

Q. What nonbypassability charges does PGE propose in this case?

A. PGE proposes nonbypassability charges to the following programs: 1) Solar Payment Option, Schedule 137; 2) Transportation Electrification, Schedule 150; 3) Demand Response program, Schedule 135, and 4) Flexible Load plan. Additionally, PGE suggests the Commission address the nonbypassability issue in UM 2024.

Q. While UM 2024 is under investigation, how will PGE deal with cost recovery associated with nonbypassability?

A. PGE suggests the Commission accept PGE's proposed nonbypassability in this case and revisit this issue after UM 2024 concludes.

Q. What principles of nonbypassability is PGE following?

A. With this proposal, PGE seeks to ensure that large nonresidential customers that choose to purchase energy from an ESS pay their fair share of system costs, including costs related to public policy directives. Investments in specified resources to achieve policy goals as legislated by the State, such as Community Solar and the Solar Payment Option, should be recovered from all customers. Similarly, investments in load-stabilizing and system reliability efforts, such as Demand Response, will provide future benefits/cost avoidance to all users of PGE's distribution system and as such should be funded by all customers, regardless of energy supplier. Transportation Electrification, in support of statewide decarbonization goals and long term load growth, should also be recovered through all customers as well.

VI. Residential Basic Charge

Q. What is Staff's recommendation relating to the residential basic charge?

A. Staff supports the separate pricing for multi-family basic charge but opposes the increase of the single-family basic charge. In its initial filing, PGE proposes to bifurcate the $11 basic residential charge and establish an $8 multi-family basic charge and a $12.50 single-family basic charge.

Q. Why does PGE propose to increase the single-family basic charge?

A. PGE proposes to increase the single-family basic charge to reflect that cost causation principle in rate design. In Exhibit 1205, PGE demonstrates that the cost of serving a residential customer in a single family dwelling was about 27 percent higher than serving residential customers in multi-family dwellings. Increasing the basic charge for single family customer shares the same rate design principle applied to the multi-family customers. Accepting the multi-family basic charge decrease but rejecting the increase to single-family basic charge is inequitable and should be rejected by the Commission. Without this increase to single-family basic charge, approximately $9.7 million in revenue that is currently collected via the basic charge must be recovered through volumetric charges and PGE will bear a greater risk to recover that portion of fixed costs.

Q. When was PGE's last material increase in its residential basic charge?

A. The residential basic charge increased from $5.50 to $10 in 2001, twenty years ago.

Q. What is annual percentage increase in the basic charge assuming it moves to $12.50 for single family in 2022?

A. Over the last twenty years, the annual percentage increase would be 1.1%, less than the rate of inflation, reflected by 2.1 percent increase in the consumer price index, over that time period [5].

Q. Some might argue that low use or low-income residential customers may be harmed by an increase to the basic charge for single family customers. Does PGE plan to file a low-income residential customer offering prior to the effective date of this case?

A. Yes, PGE plans to introduce an interim low-income rebate program before the effective date of this case. The low-income rebate is expected to more than cover any increase to the basic charge for single family residential customers, assuming it is approved by the Commission.

Q. What is your recommendation?

A. We recommend the Commission approve PGE's initial proposal to bifurcate the residential basic charge of $11 and establish an $8 multi-family basic charge and a $12.50 single-family basic charge.

[5] The Oregon Office of Economic Analysis (2002-2021) CPI

VII. Schedule 90 Subtransmission Rate

Q. What is AWEC's proposal on Schedule 90 Subtransmission rate?

A. AWEC states that Schedule 90 should include a subtransmission rate since PGE has proposed to lower the eligibility threshold for Schedule 90 from 100 average MW (aMW) to 30 aMW. Schedule 90 will become available to more customers and adding a subtransmission rate will provide more options to customers and make it consistent with Schedule 89 rate structure.

Q. Does PGE agree with this proposal?

A. No. A subtransmission rate option for Schedule 90 is unnecessary. PGE's largest customers are all primary voltage and only five legacy customers are on the Schedule 89 subtransmission rate. No new subtransmission services have been initiated in the last 16 years.

VIII. Service Charges

Q. Parties propose multiple changes to service charge related fees and charges? Please summarize.

A. The following changes are proposed to service charge items in PGE's tariff:

a. Staff does not support PGE's Residential line extension allowance proposal and argued that PGE has had a new residential line extension allowance approved by the Commission less than a year ago and should not revisit this allowance amount until June 30, 2024.

b. Staff also askes PGE to provide a service guarantee before charging customers for the temporary service charge.

c. CUB proposes that PGE should stop collecting residential customer deposits because deposits increase the energy burden on low income customers.

d. Staff and CUB propose that PGE should change the fee free bank card cost allocation.

Q. Does PGE agree with any of these proposals?

A. Yes, one. PGE agrees with the parties' fee free bank card cost allocation proposal and addresses this issue later in this testimony.

Q. How does PGE respond to Staff's recommendation that PGE should not increase the Residential Line Extension given the recent revision in 2020.

A. PGE does not agree with Staff's recommendation. In Order No. 20-483 the Commission approved PGE's request to bifurcate its Residential Line Extension Allowance (LEA) and create two Residential LEAs: an All-Electric LEA category, and an LEA category for residences not primarily heated with electricity. The Commission imposed the following condition in Order No. 20-483 states, "No later than June 30, 2025, the Company agrees to initiate a review, along with Staff and other interested parties, of the residential LEAs using updated PGE energy use data for newly constructed residential homes." PGE's interpretation of this condition is, PGE cannot update the average energy usage it uses as part of the Residential LEA formula, but this condition does not preclude PGE from updating the Residential LEAs it offers to Residential Customers based on the updated Basic and Distribution Charge Revenues proposed in UE 394. The review is meant to evaluate the effectiveness of the bifurcated residential LEA, not the price within the LEA. PGE's proposed Residential LEAs amounts were calculated using the updated Basic and Distribution Charge Revenues only. PGE used the same average energy usage and revenue multiplier that was used when the Residential LEAs were updated in 2020. It is standard practice to periodically update LEA amounts when prices change.

Q. Why is PGE offering Residential Line Extensions that are 18 percent higher than the current offering?

A. Prior to 2020's Residential LEA update, the Residential LEA had not been updated since 2011. Between UE 215 (the general rate case 2011) and UE 394 (the general rate case 2022), PGE's Basic and Distribution Charge Revenues have increased by 57% while the Residential LEA was based on revenues that were over 10 years old. This increase in the Basic and Distribution Charges over that time period indicates that PGE still has room to increase the Residential LEA it offers customers. A 57% increase in the residential LEA over that time would equal an LEA of $2548, which is higher than the average residential LEA amount that PGE proposes in this case.

Q. Did PGE update the revenue multiplier it uses to calculate its Residential LEA in Advice Filing 1130?

A. Yes. PGE updated the revenue multiplier it uses to calculate its Residential LEA from a revenue multiplier of 4 to a revenue multiplier of 3 to ensure PGE's Residential LEA reflects the average cost to install new residential service. If PGE were to use a revenue multiplier of 4 based on the proposed Basic and Distribution charges in UE 394, the All-Electric Residential LEA would be $3,547 and residences not primarily heated with electricity LEA would be $2,489. This is substantially higher than the $2,660 All-Electric Residential LEA and $1,867 for residences not primarily heated with electricity LEA PGE has proposed.

Q. Why does PGE think now is an appropriate time to update the Residential Line Extension Allowance?

A. PGE proposes to update the Residential LEAs as well as the Commercial LEAs now so that all LEAs will be based on the updated Basic and Distribution Charges from the same GRC. Currently the Residential LEAs are calculated using the Basic and Distribution Charge Revenues from UE 335 (the general rate case 2019) and the Commercial LEAs are calculated using the Basic and Distribution Charge Revenues from UE 215 (the general rate case 2011). If approved, all allowances would be calculated using the Basic and Distribution Charge Revenues from the same GRC, UE 394.

Q. How does PGE respond to Staff's recommendation that increasing prices for Temporary Services in the Company's Schedule 300 not be approved?

A. PGE does not agree with Staff's recommendation. In PGE's opening testimony in Exhibit 1200, PGE describes the purpose of the charges contained in the Company's Schedule 300 tariff. Schedule 300 is a schedule designed to directly assign and charge costs to customers who request services that are not generally within the normal operations of PGE's business and are specifically benefitting the requesting customer. When these services are requested, the costs are assigned directly to the requesting customer. This direct application of cost-causation is consistent with Bonbright's principles[6] of rate design.

Q. How does PGE respond to Staff's concern from UE 319 (the general rate case 2018) 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?

A. PGE disagrees that the complaints about the length of time PGE takes to energize the temporary service after the customer has requested the service, is still a significant concern. When a customer reaches out to the PUC's Consumer Services Section with an inquiry, they contact PGE as part of their investigation. Between 2018 and 2020, PGE received 23 total inquiries from the PUC's Consumer Service Section related to new service delays (the 23 inquiries are inclusive of temporary and permanent service customer complaints) out of the over 6,000 new service connections PGE performed. Of the inquiries made, only 2 resulted in any PGE At-Fault finding.

Q. Please respond to Staff's proposal that PGE implement a service guarantee to Customers requesting temporary service from PGE?

A. A service guarantee is unnecessary. PGE has made great progress since UE 319 to improve the customer experience when a customer requests new service from the Company. PGE has created and launched an online tool called PowerPartner on the Company's website where builders and customers can view the status of their projects and communicate with their assigned PGE project manager. This online tool was launched at the end of 2020 and OPUC

[6] Principles of Public Utility Rates," by James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, 2nd Edition, 1988.

Consumer Services inquiries about the length of time PGE takes to energize new service have significantly declined. Through October 2021, PGE has only received two OPUC Consumer Services Section inquiries. Of those zero resulted in an At-Fault finding.

Q. What does CUB recommend with regard to residential customer deposits?

A. CUB expressed the concern that "customer deposits increase energy burden for residential customers." CUB further stated:

> residential customer deposit policies explicitly target customers who are more vulnerable and can least afford a deposit. There is a housing crisis in the Portland metro area and deposits can make the situation worse. Low-income customers are often forced to choose which bills they can afford to pay, and deposits exacerbate this issue. CUB is also concerned that due to the COVID-19 pandemic shutdown, many customers have bill arrearage problems which could lead to more customers being subject to deposits.[7]
>
> To make energy services more accessible to low-income customers, CUB recommends that as of the rate effective date of this general rate case, PGE no longer collect residential customer deposits. CUB estimates the revenue requirement of this change to be $251,000 and proposed to add this amount to PGE's request.

Q. Does PGE agree with CUB's recommendation to stop collection of residential customer deposits?

A. No. Because PGE provides energy services to customers in advance of receiving payment, there is a risk that the payment will not be timely made or made in full. In order to manage the company's business risk, customers who cannot meet creditworthiness are assessed a deposit that is held by the company and is used to cover the customer's bill should that customer fail to make a payment. PGE pays interest on customer deposits held. OAR 860-021-0200 through 860-021-0215 provide guidelines to utilities to determine how to manage

[7] CUB/100/page 3/lines 13-20

business risk by establishing credit with residential customers as well as guidance on determining the amount of the deposit[8].

Q. How can a customer show creditworthiness?

A. A customer can show creditworthiness in three ways, as described in Rule E in PGE Advice No. 20-44[9]:

- Verify from a previous utility 12 months of continual service without disconnection;
- If customer had 12 months of continual service from PGE in the last 24 months without disconnections; and
- In the customer provides proof of employment for the entire 12 months prior to the application. PGE must be able to verify the employment.

Q. Is there a current docket that already discusses customer deposits?

A. Yes. On September 4, 2020, in response to the COVID-19 pandemic, the OPUC opened a docket to investigate the effects of COVID-19 pandemic on utility customers in Docket No. UM 2114. On October 2, 2020, the Commission issued an order memorializing the joint stipulation by the utilities stating that "utilities will waive new deposit requirements associated with late or nonpayment, arrearages, or credit related issues for new or existing residential customers, through October 1, 2022.[10]" Although the first stipulation agreed to suspend fees to alleviate financial stress during the pandemic, the discussion about the role of deposits is still ongoing. In the most recent Staff report filed on November 10, 2021, Staff notes that "Joint Stakeholders recommend that the Commission eliminate late-payment, disconnection,

[8] https://oregon.public.law/rules/oar_860-021-0200
[9] PGE, Rule E. Advice No. 20-44, Establishing Credit/Treatment of Deposits, Section B. The Tariff rule is modeled on the Commission's 860-021-0200 rules.
[10] https://apps.puc.state.or.us/orders/2020ords/20-324.pdf, Appendix A, page 6

and reconnection fees, deposit requirements associated with late or no-payment, arrears, or credit related issues, and reporting to credit agencies.[11]" This docket addresses customer needs for all utility customers across the State of Oregon and the decisions reached in that docket will be applicable to all utilities, not just PGE.

Q. What is PGE's response?

A. Although PGE is not opposed to having a conversation about the role of customer deposits and their effect on low-income communities, this general rate case is not the appropriate place to address this issue. The customer deposit rules are defined in the Commission's Administrative Rules and should be discussed in a Rulemaking Proceeding or decided as part in a policy docket that would affect all utilities. This conversation should happen with all utilities and not be part of one utility's general rate case process. In any event, CUB's proposed increase of $251,000 is well below the standard deposits typically held by PGE. In 2019, PGE held $2.6 million in deposits; $1.8 million Commercial and $0.86 million Residential. The proposed increase in O&M costs neither mitigates the risk nor sufficiently replaces the working cash that was provided by the deposits.

Q. Please describe how PGE currently recovers costs for the Fee Free Bank Card (FFBC) Program.

A. The costs of the FFBC program are embedded in the electronic bills and payments resource center. The combined costs are allocated across all customer classes based on the percentage of customers enrolled in paperless billing. PGE has applied this methodology since 2015 when the costs for electronic bills were allocated to customers under 200 kW.

[11] https://edocs.puc.state.or.us/efdocs/HAU/um2114hau132114.pdf

The program costs are weighted toward customer classes enrolled in paperless billing as they are more likely to use FFBC program. Residential and small nonresidential customers are appropriately allocated most of the costs with approximately 93% of the costs being allocated to Schedule 7 customers and approximately 6% being allocated to Schedule 32 customers.

Q. What is Staff's position on allocating Fee Free Bank Card costs?

A. Staff recommends that PGE change the method of allocating the costs of the FFBC program. Instead of allocating costs across all customer classes based on the percentage of customers enrolled in paperless billing, PGE should allocate costs to each customer class based on the percentage of FFBC costs incurred by that customer class. Staff believes the current method of allocation is not equitable and results in residential customers bearing more costs than non-residential customers.

Q. What is CUB's position?

A. CUB recommends that bill payments cost allocation be separated between residential and non-residential customers, and that allocating transaction costs to the customer class that drives those costs, will avoid cross-subsidization. "CUB recommends directing allocating FERC account 454 in a two-step approach. First, costs should be directly allocated between residential and non-residential customers. Second, within the nonresidential group, non-residential customers costs under account 454 should be allocated based on number of paperless bill customers."

Q. What is PGE's response?

A. Prior to April 2020, PGE did not offer FFBC program to non-residential customers and therefore the allocation method was equitable and reasonable. However, with the addition of non-residential customers to the program, a new cost allocation approach is appropriate. PGE agrees with parties and proposes to change the method of cost allocation so that each customer class will be allocated the costs incurred by that class. As a result of this change, in 2022, customer classes with the largest allocation of FFBC fees will be customers in Schedules 32 and 83. Please see Exhibit 2202 for the detailed workpaper with the proposed cost allocations to customer classes.

IX. Other Schedules

Q. Did parties provide recommendation on other issues or rate schedules?

A. Yes.

a. Staff in Exhibit 1500 recommends approval of Schedule 150 Transportation Electrification Cost Recovery Mechanism.

b. AWEC in Exhibit 100 recommends a new rate schedule for onsite battery storage tariff.

c. AWEC in Exhibit 200 supports PGE's offering of new large load COS schedule and recommends PGE base this program on NV Energy's Large Customer Market Price Energy tariff.

d. CUB proposes making PGE's Habitat Support Adder a separate option, accessible to all Schedule 7 and 32 customers regardless of enrollment in other renewable options, in CUB Exhibit 300.

e. Staff explicitly does not recommend incorporating rate design aspects stemming from HB 2475 (2021 legislation addressing energy burdened residential customers) in this rate case.

Q. Does PGE agree with AWEC's proposal to create a new Schedule 77R Onsite Battery Storage Replacement Tariff?

A. PGE is open to discussing this proposal further with AWEC and interested customers to determine if there is interest in an Onsite Battery Storage Replacement Tariff. PGE is unsure if a Schedule 77R is the appropriate tariff for Commercial Customers interested in Battery Storage. The "Seventy" rate schedule series in PGE's tariff book are tariffs specific to large industrial customers such as paper mills who supply all or some portion of their load by self-generation. There are currently no customers on these rate schedules and it has been several years since a customer utilized these rate schedules.

Q. Does PGE agree with CUB's proposal to make Habitat Support its own option?

A. This issue is more appropriately addressed in Docket No. UM 1020 regarding Portfolio Options, originally created in SB 1149. PGE is not the only utility with a Habitat Support option. Evaluating Habitat Support in UM 1020 ensures consistency among utility optional programs for customers within the portfolio of rate options.

Q. What is PGE's response to Staff's recommendation that HB 2475 rate design elements be implemented outside of this rate case?

A. PGE agrees. As PGE has discussed with Staff and others, we plan to submit a proposal to provide a bill discount for low-income customers in alignment with the principles set forth in HB 2475. We see this proposal as interim and will provide support to customers while a longer-term effort examines statewide opportunities afforded by the new legislation. PGE echoes Staff's opinion on the importance of stakeholder input and has extended opportunities to provide funding for advocates to participate in the process considering our interim filings. We also intend to participate in the larger investigatory process led by Staff in 2022.

X. Decoupling

Q. What is the purpose of this portion of your testimony?

A. The purpose of this portion of our testimony is to address the responses of Staff and CUB to PGE's decoupling proposal.

Q. Please summarize your proposal for changes to PGE's Schedule 123 Decoupling.

A. We propose the following modifications to Schedule 123:

- Extend Schedule 123 through December 31, 2025
- Apply the Sales Normalization Adjustment (SNA) to Schedules 38/538, 47, and 49/549;
- Keep the 2% limiter but include the ability to balance any amounts over 2% to the subsequent year or years.

Q. How did the Parties response to PGE's decoupling proposals.

A. Both Staff and CUB support extending Schedule 123 through December 31, 2025 and oppose carrying over any balance above the 2% limiter. Staff opposes expanding decoupling to Schedules 38/538, 47, and 49/549.

Q. What did Staff investigate to make this recommendation for Schedules 38/538, 47, and 49/549?

A. Staff reviewed the customers profiles and usage under these schedules and concluded that the volatility in usage and change in customer composite over time will cause unnecessary risk shift from the Company to customers, if SNA expands to these schedules.

Q. Do you agree with Staff's conclusion?

A. No. PGE opposes removing Schedules 38 and 538 in PGE's proposal to apply the SNA. However, PGE does not oppose removing Schedules 47 and 49 from its proposal to apply the SNA.

Q. Why does PGE want to apply the SNA to Schedules 38 and 538?

A. As Staff mentions in their reply testimony Schedules 38 and 538 large nonresidential time-of day service is an optional schedule to large nonresidential customers under Schedule 83. Since the SNA is already applied to Schedule 83 and 583 customers, the SNA should also apply to customers who are on Schedules 38 and 538. If PGE did not offer Schedules 38 and 538 as an optional schedule to Schedule 83, customers currently on these Schedules would be on Schedules 83 and 583 and the SNA would have already applied to them. This may have been an oversight when the Commission expanded SNA decoupling to Schedules 83 and 583 in UE 335, Order No. 18-464.

Q. How do you respond to Staff's and CUB's recommendation on 2% limiter?

A. PGE does not agree with Staff's recommendation on 2% limiter. Disallowing carryover balance in decoupling is disallowing full recovery of the fixed cost utilities prudently invested to serve customers. It's an example of an asymmetrical mechanism without any justification. PGE does not propose to recover more than 2% in any given year. It expects any balance to be collected from customers will eventually reverse.

Q. Staff argues that allowing the carryover balance above 2% limiter will cause a large shift in risk from the Company to customers. Any comments?

A. There is no merit to this argument, and PGE disagrees. PGE has an obligation to serve customers, which includes incurring fixed costs to serve expected load that is largely charged on the basis of kWh sales volumes. With 2% limiter, PGE may not be able to recover prudently incurred fixed costs and may cause unreasonable levels of financial volatility.

The current rates are set based on a foreseeable demand, which does not account for the massive economic shutdown resulting from the pandemic. With the drastic change in the demand, the utilities might not recover the actual costs to provide services. Allowing excess balances that are a charge to customers to be carried forward can reasonably manage the price impacts. In addition, the 2% limiter does not apply to credits due to decoupling. Any charge in one year in excess can net against credits in future years, which can stabilize price impacts. Allowing the 2% limiter carryover will provide price stability for customers as well as revenue stability for PGE, which reduces the overall risk.

Q. Please address Staff's claim that carrying forward excess balances more than 2% harms customers.

A. Staff simply makes the claim with no rationale that allowing balances to carry forward will harm customers. Using Staff's logic, simply charging customers for service provided will harm customers. Allowing excess balances that are a charge to customers to be carried forward is a reasonable balance between shareholders and customers while allowing price impacts to customers to be reasonably managed.

Additionally, the Commission has approved another utility's decoupling mechanism that allows for excess balance carryover. In UM, 1753, Order No. 16-076 the Commission approved Avista's decoupling mechanism which provides a 3% limit on the decoupling charge to customers and includes a carry forward provision. Since the Commission has approved Avista's decoupling mechanism, a precedent exists to approve PGE's decoupling proposal.

Q. CUB states that the decoupling mechanism along with 2% limiter was first introduced during 2009 international banking crisis and the Great Recession and it shouldn't be removed. Please comment.

A. The recent economic downturn related to the COVID-19 pandemic does have more significant impacts on electricity usage among different customer classes. The impact is unique and first of its kind in years. Small and large nonresidential customers' electric usage dropped to an unexpected low level. The lower usage results in a total of $17.8 million balance to be collected from customers; however, the actual collection is only $9.7 million and $8.2 million balance is ineligible for collection due to 2% limiter in 2022. On the other hand, high residential usage resulted in a significant refund of $17 million which is not subject to any limiter. The adverse and unbalanced impact of 2% limiter is amplified in the current pandemic.

XI. Transportation Electrification related Line Extension Allowance

Q. Please summarize Staff's concerns with PGE's calculation of Transportation Electrification (TE) -related Line Extension Allowances (LEA) and their proposed adjustments.

A. Staff concluded that PGE's forecasting methodology in determining the LEA is reasonable, but that the company applied an unreasonably high demand factor (DF) when estimating the annual energy (kWh) at TE-related sites. Staff used data provided by PGE to propose adjustments to certain LEAs.

Q. How does PGE respond to Staff's concerns?

A. Staff lacked sufficient data to make LEA adjustments, since TE-related LEA calculations occasionally deviate from the typical process. A typical LEA calculation uses site capacity, hours per year of use, and estimated DF to estimate the future load. Some TE-related LEA calculations are instead based on the estimated electric vehicle (EV) adoption forecast, EV types and expected usage level from each EV type, or historical information from similar sites, to estimate the future load.

Q. Please describe the rationale behind PGE's line extension allowance calculations and how demand factors are used in those calculations.

A. PGE's line extension allowance calculation process typically uses demand factors to estimate the annual kWh that PGE can expect from a site, and then calculates the customer's LEA. The LEA calculator form that the company uses typically contains both calculations. DFs, combined with hours per year of use, are typically used for energy estimates because loads such as lighting, computers, etc. can be relatively consistent throughout the hours they are in use. However, TE-related sites don't always have consistent load over the course of the day, meaning demand factors and hours per year are not always useful to estimate the annual kWh PGE can expect from these sites. For these reasons, PGE does not always use DF and hours per year to estimate TE-related load. Where better methodologies exist to estimate a site's kWh, PGE uses those methodologies, then uses the LEA calculator form to calculate the LEA. In these cases, the default value of 8760 remains in the hours per year field in the LEA calculation form; however, this value is not part of the calculation because the demand factor equation is not being used to calculate the kWh.

Q. Was PGE's LEA calculation for a [START CONFIDENTIAL] [redacted] [END CONFIDENTIAL] reasonable?

A. Yes. In 2019, PGE calculated a LEA for a **[START CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** based on the number of vehicles forecasted in a third-party fleet electrification plan that the customer provided. These calculations were based on distance (miles traveled per day per vehicle) and efficiency (kWh per mile), along with a vehicle adoption forecast. While this approach deviates from the typical LEA calculation methodology, the approach was appropriate, given that an accurate estimate of kWh per year is the goal of a LEA calculation. In 2020, PGE conducted similar analysis in its economic modeling in ADV 1149; however, since this was a model designed to represent a range of possibilities, rather than a site-specific forecast, in ADV 1149 PGE used more conservative assumptions as to how many vehicles would be supported by the planned-for EVSE at such a site. The use of different assumptions by PGE in economic modeling in the product development process versus in a site-specific LEA calculation does not imply that the LEA calculation was inherently imprudent.

Q. What adjustments did Staff make to PGE's other LEAs?

A. Staff made LEA adjustments to 12 additional sites, based on 2018 charger utilization rates from PGE's public Electric Avenue site at World Trade Center. Staff contends that its adjustments were reasonable because the sites it adjusted are all public charging sites and are therefore comparable to Electric Avenue.

Q. Were all the sites that Staff adjusted public charging sites?

A. No. Of the 12 additional sites where Staff adjusted PGE's LEA, only four were identified by PGE as public charging sites. Six additional sites are fleet charging, workplace charging, or car dealerships. The remaining two site types were unknown to PGE; however, these are unlikely to be public charging sites as PGE was unable to locate them on PlugShare, a third-party application that displays public charging for EV drivers.

Q. How does PGE respond?

A. Utilization data from Electric Avenue is not an appropriate proxy for the eight non-public charging sites.

Q. How does PGE respond to Staff's proposed adjustments to the LEA for PGE's public charging sites?

A. Out of the four public charging sites, one offers free EV charging to drivers. This makes utilization data from Electric Avenue, where drivers pay to charge, an inappropriate proxy for this site. The three other sites are known commercial charge point operators for which PGE used customer-specific comparative data to estimate kWh and calculate LEAs. Since the estimated kWh per site was calculated in an alternative way, LEA calculation forms for these sites contain only the LEA calculations, not the kWh calculations. Therefore, Staff's adjustments are based on incomplete data.

Q. How does PGE calculate LEAs for EV charging sites?

A. As noted in the company's response to OPUC Data Request No. 738, PGE's approach to its LEA calculations for EV charging sites is still evolving. We prioritize using the best data and methodology available for each site to develop the most accurate forecast of kWh.

Q. Where does PGE discuss the revenue requirement recommendation of Staff's proposed adjustments to PGE's TE-related line extension allowances?

A. PGE presents its recommendation in PGE Exhibit 1700.

XIII. Line Losses

Q. Does PGE have any updates on the line loss study submitted in opening testimony?

A. Yes, PGE added a small amount of non-substantive text to the line loss study that was submitted with our opening testimony. The added text identifies the loss rate within our transmission system infrastructure, a requirement for PGE's Transmission Rate Case filed with the Federal Energy Regulatory Commission. No adjustments were made to the analysis and no additional analysis was conducted. The revised study is included in work papers associated with this testimony.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

Exhibit 2201 is voluminous in
size and provided only in
electronic format

PORTLAND GENERAL ELECTRIC
2022 MARGINAL ENERGY COSTS

Schedule	Busbar Energy (MWh)	Marginal Energy Cost
Schedule 7	8,057,887	$303,298,538
Schedule 15	14,813	$489,975
Schedule 32	1,689,604	$63,106,505
Schedule 38	29,124	$1,086,697
Schedule 47	20,966	$829,149
Schedule 49	65,981	$2,632,499
Schedule 83	3,054,545	$114,303,541
Schedule 85	2,788,811	$101,805,487
Schedule 89	832,935	$30,245,080
Schedule 90-P	3,007,082	$108,800,111
Schedule 91/95	46,684	$1,544,184
Schedule 92	2,741	$98,986
TOTALS	19,611,174	$728,240,752

PORTLAND GENERAL ELECTRIC
2022 MARGINAL ENERGY AND CAPACITY COSTS

Year	Thermal Capacity SCCT $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2022	84.94	32.22	43.88	20.00%	84.94	34.55
2023	86.63	32.86	44.75	20.00%	86.63	35.24
2024	88.37	33.52	45.65	20.00%	88.37	35.95
2025	90.13	34.19	46.56	27.00%	90.13	37.53
2026	91.93	34.87	47.49	27.00%	91.93	38.28
2027	93.77	35.57	48.44	27.00%	93.77	39.05
2028	95.64	36.28	49.41	27.00%	95.64	39.83
2029	97.56	37.01	50.40	27.00%	97.56	40.62
2030	99.51	37.75	51.40	35.00%	99.51	42.53
2031	101.49	38.50	52.43	35.00%	101.49	43.38
2032	103.52	39.27	53.48	35.00%	103.52	44.24
2033	105.59	40.06	54.55	35.00%	105.59	45.13
2034	107.70	40.86	55.64	35.00%	107.70	46.03
2035	109.85	41.67	56.75	45.00%	109.85	48.46
2036	112.05	42.51	57.88	45.00%	112.05	49.43
2037	114.29	43.36	59.04	45.00%	114.29	50.41
2038	116.57	44.22	60.22	45.00%	116.57	51.42
2039	118.90	45.11	61.42	45.00%	118.90	52.45
2040	121.28	46.01	62.65	50.00%	121.28	54.33
2041	123.70	46.93	63.90	50.00%	123.70	55.41
Real Levelized	$84.94	$32.22	$43.88		$84.94	$36.01
NPV	$1,114	$423	$576		$1,114	$473
Nominal Levelized	$99.19	$37.63	$51.24		$99.19	$42.05
Real Levelized	$84.94	$32.22	$43.88		$84.94	$36.01

Composite Income Tax Rate			27.00%
Property Tax Rate			1.45%
Inflation Rate			2.00%
Capitalization:			
Preferred	0.00%	0.00%	0.00%
Common	50.00%	9.50%	4.75%
All Equity	50.00%		4.75%
Debt	50.00%	4.13%	2.06%
Cost of Capital			6.81%
After-Tax Nominal Cost of Capital			6.26%
After-Tax Real Cost of Capital			4.17%

PORTLAND GENERAL ELECTRIC
SUMMARY OF MARGINAL COST STUDY

SCHEDULE	SUBTRANSMISSION COSTS	SUBSTATION COSTS	FEEDER BACKBONE COSTS	FEEDER TAPLINE COSTS	SERVICE & TRANSFORMER COSTS	METER COSTS	CUSTOMER COSTS
Schedule 7 Residential							
Single-phase	$4.17	$10.68	$29.14	$40.48	$74.68	$22.05	$45.29
Three-phase	$4.17	$10.68	$29.14	$40.48	$164.36	$51.68	$45.29
Schedule 15 Residential	$4.17	$10.68	$30.41	$40.56	$2.42	N/A	$28.37
Schedule 15 Commercial	$4.17	$10.68	$30.41	$40.56	$2.42	N/A	$24.86
Schedule 32 General Service							
Single-phase	$4.17	$10.68	$35.13	$61.90	$157.85	$47.76	$71.76
Three-phase	$4.17	$10.68	$35.13	$16.39	$265.66	$66.13	$71.76
Schedule 38 TOU							
Single-phase	$4.17	$10.68	$36.04	$63.08	$165.25	$54.31	$313.52
Three-phase	$4.17	$10.68	$36.04	$18.44	$488.06	$108.52	$313.52
Schedule 47 Irrigation							
Single-phase	$4.17	$10.68	$35.13	$58.44	$9.05	$54.86	$63.69
Three-phase	$4.17	$10.68	$35.13	$15.47	$18.00	$75.87	$63.69
Schedule 49 Irrigation							
Single-phase	$4.17	$10.68	$36.04	$60.92	$121.75	$54.86	$271.18
Three-phase	$4.17	$10.68	$36.04	$17.81	$121.75	$65.99	$271.18
Schedule 83 Secondary General Service							
Single-phase	$4.17	$10.68	$36.04	$63.08	$364.47	$54.86	$475.81
Three-phase	$4.17	$10.68	$36.04	$18.44	$974.14	$114.60	$475.81
Schedule 85 Secondary General Service	$4.17	$10.68	$26.84	$6.72	$2,242.07	$123.23	$1,391.83
Schedule 85 Primary General Service	$4.17	$10.68	$26.84	$6.72	$0.00	$1,985.33	$1,391.83
Schedule 89 Secondary	$4.17	$10.68	$70,405	N/A	$17,117.73	$123.23	$7,197.73
Schedule 89 Primary	$4.17	$10.68	$70,405	N/A	$0.00	$2,097.42	$7,197.73
Schedule 89 Subtransmission	$4.17	N/A	$73,568	N/A	N/A	$19,844.95	$7,197.73
Schedule 90 Primary	$4.17	$10.68	$331,061.00	N/A	$0.00	$2,097.42	$42,902.83
Schedules 91 & 95 Streetlighting	$4.17	$10.68	$30.41	$42.63	$2.42	N/A	$379.06
Schedules 92 Traffic Signals	$4.17	$10.68	$30.41	$15.12	$7.72	N/A	$277.12