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June 6, 2018

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 335 – In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY, Request for a
General Rate Revision.

Enclosed for filing is Staff Opening Testimony (400 – 1002). A certificate of service, service list, CDs (confidential and non-confidential) are included with this filing.

Exhibit(s) 402, 500, 503, 603, 604, 800, 802, 805, and 900 have confidential information and that information is being provided to parties who have signed Protective Order No. 18-047 electronically (via Huddle) along with any workpapers from Staff.

/s/ Mark Brown
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CASE: UE 335
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

June 6, 2018

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

A. My name is Marianne Gardner. I am a senior revenue requirement analyst employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I am the revenue requirements summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding. I introduce Staff-sponsored adjustments and issues regarding the Portland General Electric Company (Portland General Electric, PGE, or Company) request for a general rate revision, docketed as Docket No. UE 335. As such, I verify PGE's proposed revenue requirement utilizing Staff's revenue requirement model. This model is also used to calculate Staff's modified revenue requirement after incorporating Staff's proposed adjustments to NWN's revenue requirement.

Additionally, I provide background regarding specific issues I reviewed, and my analysis and recommendations.

Q. Will other Staff witnesses submit testimony regarding the issues they reviewed?

A. Yes. Each Staff assigned to Docket UG 344 is submitting separate testimony. In Part 1 of my testimony, I introduce the Staff witnesses and their respective assignments, and estimate the revenue requirement impact of Staff recommended adjustments to the Company's initial filing. These are the issues identified to date. Staff's recommendations and issues may change after reviewing testimony and analysis by other parties.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit 401	Witness Qualification Statement
Exhibit 402	PGE Responses to Staff Data Requests
Exhibit 403	Escalation – Excerpts from Consumer Price Index – All Urban Consumers for the U.S., published by OEA (released February 16, 2018)
Exhibit 404	Staff Outstanding Data Requests to PGE

Q. How is your testimony organized?

A. My testimony is organized as follows:

PART 1. REVENUE REQUIREMENT

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

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

Q. What revenue requirement is PGE asking for in this docket?

A. PGE requests that prices be adjusted to yield $85.9 million of additional revenues, for a total revenue requirement of $1,884.6 million.

The proposed increase represents a 4.8 percent increase overall for cost of service and direct access customers beginning January 1, 2019.[3] PGE bases its proposed revenue requirement on a 12-month test year starting January 1, 2019.

Q. What is Staff's recommendation regarding PGE's proposed increase?

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[1] Order No. 01-787, pp. 5-6.
[2] Order No. 86-477 (1986 WL 1300169).
[3] PGE/100, Pope-Lobdell/12.

A. Staff proposes several adjustments to PGE's requested test year expense as well as proposed additions to rate base. In addition, Staff, PGE, the Alliance of Western Energy Customers (AWEC), and the Oregon Citizens' Utility Board (CUB) have reached a settlement agreement in principle that reduces PGE's proposed test year expense. The settlement agreement is not yet executed and its terms will not be discussed in this testimony.

Staff notes that this is the fifth rate case PGE has filed in six years. Each of the previous four cases has resulted in rate increases. In reviewing PGE's requested rate increase for 2019, Staff considered the incremental increases in rates PGE has received since 2013.

Q. Please provide a list of the rate case topics that Staff reviewed for opening testimony that an adjustment to revenue requirement is proposed and introduce the responsible Staff.

A. I have provided a listing of rate topics in Table A.

Table A

Testimony	Staff	Issue	Proposed Staff Adjustments	Revenue	Expense	Rate Base	Revenue Requirement Effect
400	Gardner	1	**Working Cash factor - 3.8270 (and incremental Working Cash in model)**			**(1,469)**	**(95)**
400	Gardner	1	**Working Cash in rate base**			**(3,610)**	**(338)**
400	Gardner	2	**Board of Director Expenses**		**(181)**		**(187)**
400	Gardner	2	**Board of Director Expenses (placeholder for RSUs)**				**0**
400	Gardner	3	**Salaries, Wages, Incentives, FTE**		**(23,924)**	**(9,921)**	**(25,697)**
500	Fox	1	**Misc. A&G**		**(2,697)**		**(2,792)**
500	Fox	3	**Continuity & Membership Credits**		**(800)**		**(828)**

Testimony	Staff	Issue	Proposed Staff Adjustments	Revenue	Expense	Rate Base	Revenue Requirement Effect
500	Fox	3	**Main All Risk Prop. Premium**		**(151)**		**(156)**
500	Fox	3	**Retained Losses**		**(442)**		**(458)**
500	Fox	4	**Employee Benefit Administration**		**(400)**		**(414)**
500	Fox	5	**Income Tax, ADIT, EDIT (placeholder)**				**0**
500	Fox	6	**Property Tax Expense (placeholder to adjust based on final plant in rate base)**				**0**
600	Watson	2	**Meals & Entertainment**		**(1,635)**		**(1,693)**
600	Watson	2	**Travel**		**(23)**		**(23)**
600	Watson	2	**Awards**		**(129)**		**(133)**
600	Watson	3	**Fee-free Bankcard**		**(257)**		**(266)**
400	Gardner	4	**Depr., Amort. & Reserves (to be adjusted based on final plant)**				**0**
700	Moore	1	**Storm Accrual**		**0**		**0**
700	Moore	2	**Demand Response Program**		**(2,400)**		**(2,485)**
800	Kaufman	1	**Revenue**	**(2,023)**	**(64)**		**2,020**
800	Kaufman	2	**IT O&M Costs**		**(18,143)**		**(18,783)**
800	Kaufman	3	**CET**			**(81,500)**	**(7,632)**
800	Kaufman	3	**Plant**			**(224,892)**	**(21,059)**
900	Compton	1	**Rate Spread**				**N/A**

PART 2. SPECIFIC ISSUES

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

A. I reviewed the portions of the filing related to uncollectible expense, interest synchronization, cash working capital, taxes other than income, board of directors' expenses, workforce levels, wages and salaries, incentives, and contractor expense. In order to gain additional insight, I reviewed the

Company's responses to Staff's Standard Data Requests (DRs), issued approximately 30 additional DRs, and reviewed the Company's responses.

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

A. No. As noted above, Staff, intervenors and the Company have a settlement in principle that includes some of these issues. Testimony in support of the partial stipulation will be filed later. In opening testimony I address the amount of cash working capital that should be included in PGE's rate base and the appropriate amount of expense that should be included in the test year forecast for board of directors' fees and employee compensation. The amount of expense included in the forecasted test year depends on assumptions regarding the wages and salaries PGE will pay during the test year, the number of full-time equivalent employees (FTEs) that are appropriately included in the test year forecast, and the amount of contract labor that PGE will use. I address each of these assumptions in my testimony and propose adjustments to the forecasted amounts for employee compensation.

ISSUE 1. CASH WORKING CAPITAL

Q. Please explain the Commission's historical treatment of working capital?

A. "For ratemaking purposes, working capital is a measure of the amount of funding needed to satisfy the level of the daily operating expenditures and a variety of non-plant investments that are necessary to sustain ongoing operations of the utility."[4] The components of working capital are generally rate base items identified as fuel inventory, materials and supplies (M&S) inventory, prepayments not included in cash working capital (CWC), and in some circumstances, CWC. Historically, the Commission typically authorizes electric utilities to include an allowance for CWC in rate base if the utility has used a lead/lag study to estimate the factor for CWC.

Q. Please provide a summary of the Company's filed proposal for cash working capital.

A. The Company included approximately $63.2 million in rate base for CWC. As the Company explains in testimony, it updated its lead/lag study and applied the resultant CWC factor of 4.063 percent to its proposed operating expenses of $1,554.8 million to forecast the working cash.[5]

Q. Please explain generally what a lead/lag study entails and how this applied to PGE's methodology employed in its UE 335 study.

[4] Hahne, Robert L., and Aliff, Gregory E. *Accounting for Public Utilities.* Publication 16, Release 34, November 2017, Section 5-1.
[5] PGE/200, Tooman – Espinoza/19 at 12-18.

A. Generally a utility provides service prior to receipt of payment from ratepayers (revenue lag), and there is also a delay in payment for goods and services purchased by the utility (expense lead). The calculation of the appropriate level of CWC is based on the number of days of revenue lag and of expense lead PGE experiences in a test year, as well as the dollar amounts for each. To determine lead/lag days, transactions for the year are sampled and analyzed. In PGE's study, PGE grouped these transactions into a six major groups: revenue, fuel, purchased power, labor, overhead and maintenance (O&M), and taxes.

Once the lead/lag days are determined, the annual dollars for each group are multiplied by the lead/lag days to calculate the "total dollar days." The total revenue lag is calculated by dividing the total dollar days by the "annual dollars." The same is true for the total expense lead. The difference between the revenue days and expense days is divided by 365 days in the year to determine the lead/lag factor. This factor is multiplied by the total O&M expense to estimate the cash working capital.[6]

Q. Please describe Staff's analysis of the Company's proposal for CWC and the related CWC factor.

A. Staff first compared the Company's proposed lead/lag factor of 4.063 percent against the lead/lag factor proposed in its last five general rate cases (GRCs) as shown below in Table B. In column three, Staff notes whether the lead/lag

[6] UE 335 PGE Initial Application – Work papers\Non-Confidential Work papers\ Work Papers_200_Non-Conf\Working Cash Factor 2019_Lead-Lag.xlsx.

factor proposed was the result of a new lead/lag study or based on an order from a prior docket.

Table B

Docket No.	Lead/Lag percent Proposed by PGE	New Lead/Lag Study	Final Order
UE 215	3.902	Yes	3.902
UE 262	3.980	Yes	3.700
UE 283	3.700	No. UE 262	3.700
UE 294	3.628	Yes	3.628
UE 319	3.628	No. UE 294	3.628
UE 335	4.063	Yes	n/a

Q. Did the Company conduct any other lead/lag studies during this time period?

A. Staff is aware of two other studies. PGE engaged an outside consulting firm to perform a lead/lag study in order to comply with Order No. 14-422 in Docket No. UE 283. Staff accepted this study for the purpose of compliance with the order but did not agree with a few of the components included in the study. After reviewing the study with the consultant and PGE staff, Staff was agreeable to PGE's plan to use the consultant's computation for the lead/lag days in its next rate case and the Company's existing methodology for the components included in the study. This hybrid methodology of PGE's components and the consultant's calculated lead/lag days for those components was the basis for the study filed in Docket No. UE 294. Based on this study, the Company proposed a CWC factor of 3.628 percent.

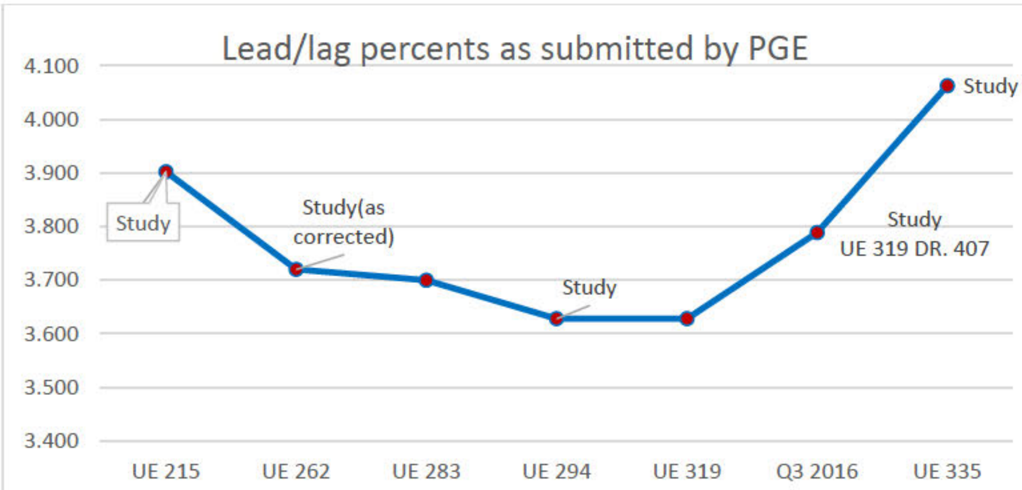
Q. Please explain the second study.

A. Staff was alerted to the second study in the Company's response to Staff DR No. 407 in Docket No. UE 319. According to the Company's response, the lead/lag study was updated in the third quarter of 2016 and resulted in a CWC factor of 3.789 percent. The Company explained that it decided to use the CWC factor of 3.628 percent approved in Docket No. UE 294 since the 3.789 percent was not appreciably different.

Q. Based on this review does Staff believe PGE's proposed CWC factor of 4.063 percent is reasonable?

A. Staff graphed the data points listed in Table B above. In Chart A below, Staff graphed the lead/lag factors PGE proposed in its current docket and the five prior dockets. Additionally, Staff included the factor for the second study mentioned above that was not used in UE 319. As shown in Chart A, it appears to Staff that the 4.063 percent is out of the norm compared to the studies PGE filed in its last five rate cases. In Chart A, please note that the second data point is corrected. PGE had made a calculation error in its filed study. The filed factor was corrected from 3.980 percent to 3.720 percent, and then adjusted once more per the stipulation to 3.700 percent to reflect Staff's premise that the Fee-Free Bankcard program would improve the lead/lag days for bill collection.

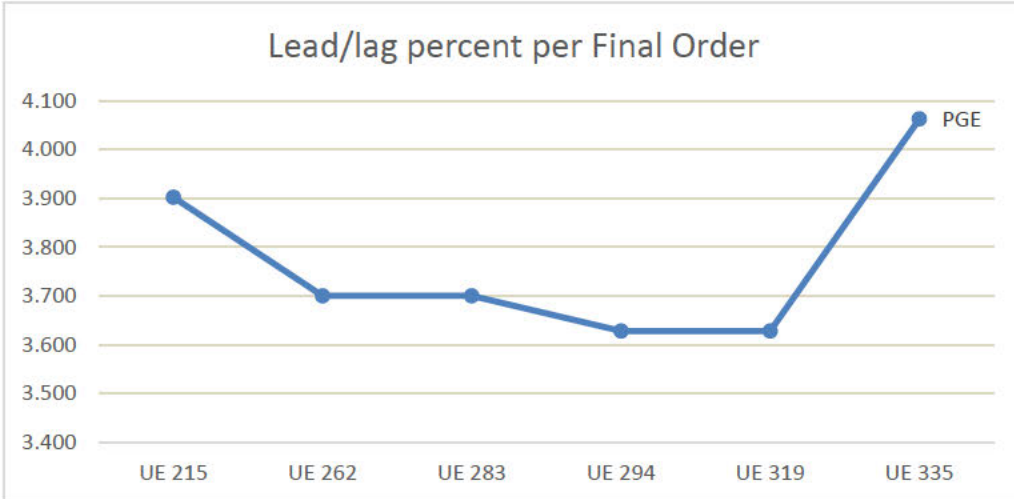
Chart A



Q. How does the proposed factor of 4.063 compare to the CWC factor used to calculate the final revenue requirement in the prior five general rate cases?

A. As shown in Chart B below, the only data point that is slightly different from PGE's filed CWC factor is in Docket No. UE 262, 3.700 versus 3.720, respectively. In UE 262, The Company had originally filed a CWC of 3.720 percent. However, Staff discovered an error in the calculation of the revenue lag days and it was corrected to 3.700 percent. Staff has included PGE's proposed factor of 4.063 percent to once again illustrate that it appears inconsistent with the final factors utilized to calculate CWC in rate base for the five previous rate cases.

Chart B



Q. Has Staff asked the Company to explain why the most recent study provided in UE 335 results in a working cash factor of 4.06 percent, which is higher than those in prior rate cases?

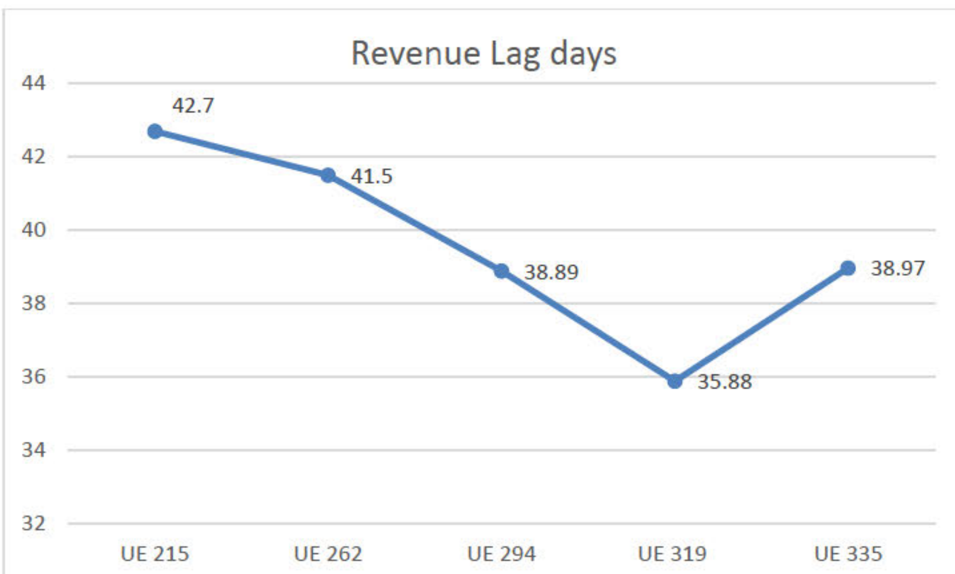
A. Yes. As the Company states in its response to Staff DR No. 312, "There are numerous differences that contribute to the higher working cash factor in UE 335 from prior years' calculations as the working capital requirements for PGE's business changes every year." The Company goes on to specifically discuss three of its defined six groupings: Revenue, Labor, and Misc. O&M expenses. Please note, in its response the Company includes the data for the study prepared for Docket No. UE 319 that was not actually used in its filed case for that case.[7]

The Company points out in its reply, "Lag days for revenue had a very large effect on the overall working cash factor due to the large dollar weighting of the

[7] Staff/402, PGE Response to Staff DR No. DR 312.

element. The lag days increased from 35.88 to 38.97, or just over three days. This increases revenue lag and increases the working cash factor for the current test year. Although this is a large increase from the UE 319 calculation, historically it is in line with prior year's revenue lag days." To test this assertion, Staff graphed the revenue lag days provided by the Company as shown below in Chart C and notes that it appears that the lag days were declining but in the UE 335 study, revenue lag days spike up.

Chart C



Q. What could be some plausible reasons for the decrease in revenue lag days?

A. Staff believes that the improvement in the Company's financial software system upgraded as part of its Vision 2020 program would increase the speed of accounting staff's transaction processing. Secondly, Staff believes acceptance of digital technology by the public in general has implications relevant to customer behavior. For instance, more customers are using electronic means such as auto-pay to pay bills, facilitating a faster transfer of cash. This allows the company access to cash sooner. Specific to PGE customers, Staff believes that the Fee-Free Bankcard program has also improved payment times and reduced delays due to late payments and uncollectible accounts.

Q. What does Staff believe is an explanation for the increase in revenue lag days in the Docket No. UE 335 study?

A. Since PGE did not provide a rationale, Staff believes that it may be an anomaly and does not represent PGE's on-going operations.

Q. As PGE noted, revenue lag has a large impact on the final CWC factor as it is a heavily weighted element. What is the impact to the CWC factor PGE proposes in this case if the lag days calculated in Docket No. UE 319 replace the lag days in the Docket No. UE 335 study?

A. The result is to reduce the lead/lag factor from 4.063 percent to 3.216 percent.

Q. What rationales does the Company describe for the decrease in expense lead days?

A. The Company based its explanation on two changes for two of the five expense groupings; labor expense and O&M expense. The Company explained that labor expense lead days have decreased because of shortened bank processing days and an increase in the number of employees requesting direct bank deposit paychecks. O&M lead days have decreased because the Company is paying vendors faster than in the prior two studies.

Q. Does Staff have any comment regarding these explanations?

A. Both explanations seem to be plausible. One observation Staff has is that companies usually do not pay vendors sooner than the payment terms unless the company receives a discount or other type of incentive. On the other hand, with the improvements in technology, vendors are probably able to bank the payments quicker. However, the dollars associated with the alleged changes to timing for these two expense groupings are only $522 thousand of the total $1.348 million of expenses, or 39 percent.

Q. What is Staff's recommendation?

A. Staff recommends averaging the CWC factors calculated in Docket Nos. UE 294, UE 319, and UE 335 because these studies are the most recent and are based on the same methodology. This results in an average CWC factor of 3.827 percent. Staff proposes applying this factor to the final O&M expense as presented in the final ordered revenue requirement. Staff's recommendation is based on the following considerations:

- The CWC factor for the test year forecasts cash working capital in rate base not for a single year but for the period of time rates are in effect;
- As demonstrated, the revenue lag has a large impact on the CWC factor; and,
- Both the revenue lag days and the UE 335 factor appear to be anomalous as compared to the prior studies.

Q. What is Staff's recommendation?

A. Staff's recommendation is to apply the average CWC factor of 3.827 percent to the final O&M expenses included in the Commission final order. Based on

Staff's opening testimony, Staff proposed test year O&M expenses are $1.419 million. Applying the 3.827 percent CWC to O&M expenses of $1.419 results in CWC in rate base of $57.067 million; a reduction to the Company's test year CWC in rate base of ($6.105) million.

ISSUE 2. BOARD OF DIRECTOR FEES

Q. Please provide a summary of the Company's filed proposal for Board of Directors (BOD) Fees.

A. The Company did not provide any testimony regarding the BOD fees included in the test year revenue requirement. However, in its response to Staff SDR No. 62 it provided the 2018 budget and the 2019 test year.[8] The total for each year is $1,288,900 and $1,321,638, respectively. The Company explained that no officer of the Company received BOD compensation and that BOD compensation includes a grant of restricted stock units (RSUs). For 2017, directors active for the entire year each received 1,945 RSUs.

Q. Please explain the Commission's historical treatment of BOD Fees.

A. The Commission disallows expense for BOD compensation paid to Company officers. Also some expenses are disallowed in whole or in part whether the director is an officer or not. These expenses are for things such as meals and entertainment; incentive pay, e.g. RSUs; awards, gifts; and non-business related expenses.

Q. Please describe Staff's analysis of the test year BOD fees.

A. Staff asked the Company to provide actual 2017 costs at the FERC account and transactional level. Staff also requested the 2018 budget and 2019 test year by FERC account and asked the Company to explain certain cost increases from the 2018 budget. Staff compared the 2017 actuals to the 2018

[8] Staff/402, PGE's Response to Staff DR No. 62.

budget and 2019 test year. Staff found that, while the 2018 budget increased by only 2.45 percent to the 2019 test year, the 2019 test year is 20 percent higher than 2017 actuals.

Q. Did the Company justify the increases to the 2019 test year?

A. The Company explained the 2.45 percent escalator applied to the 2018 budget was the same percentage used to escalate employee expenses to the test year. The Company explained the increase to director compensation as follows:

> The primary drivers behind the increase in Director compensation for 2019 is three-fold. First, there are several directors that will be nearing or reaching the mandatory retirement age in 2019. Second to attract the skill and talent at the board of director level to replace these retiring directors we need to provide competitive compensation. Third, and the most important of the drivers, is attracting and retaining directors with experience in industries that are going through transformation and those that are skilled at technology and cyber security as well as bringing more diversity to the Board.[9]

Q. Does Staff propose an adjustment to the 2019 test year expense related to the BOD?

A. Yes. Staff does not think it is reasonable to assume BOD expense will increase approximately 20 percent between from 2017 to 2019. Staff's proposed adjustment is based on a comparison of PGE's proposed expense for BOD compared to 2017 actual expense escalated to 2019 using the All-Urban CPI. Escalating 2017 actual expense to 2019 with the All-Urban CPI results in expense that is $180,843 less than what PGE includes in its test

[9] Staff/402, PGE Response to Staff DR No. 299.

year.[10] Accordingly, Staff proposes removing $180,843 from PGE's test year expense.

In addition, Staff proposes to remove from the Director compensation the amount included in the test year for RSUs. Staff believes this action is consistent with Commission precedent disallowing 100 percent of Officers' incentives from the test year. Staff has issued a DR asking the Company to provide the dollar amount of RSUs included in the test year. The response to this DR is still pending.

In addition, Staff witness Jeffrey Watson proposes removing expense for meals and entertainment, travel, awards and gifts for all employees and the BOD in his testimony.[11]

ISSUE 3. SALARIES, WAGES, INCENTIVES, AND FTE

Q. Please provide a summary of the Commission's historical treatment of wages, salaries, incentives, overtime expense, and full-time equivalents (FTEs).

A. The Commission typically uses Staff's three-year wage and salary model (W&S model) to estimate expenses for non-union wages and salaries.[12] As a starting point, Staffs model uses the utility's actual average wage and salary level as it existed three years prior to the test year.

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[10] See Staff electronic workpaper, UE 335 Exhibit 400 W&S Issue 3 CONF-Gardner.xlsx.
[11] Staff/600, Watson/6-9.
[12] See e.g., *In the Matter of PacifiCorp*, OPUC Docket UE 116, Order No. 01-787 at 40 (September 7, 2001).

From there, Staff applies the annual changes to the All Urban CPI[13] to adjust wages and salaries for each of the three subsequent years to establish a forecast of test-year wage and salary level. If the utility's projected wage and salary level is within ten percent of Staffs projection, the difference between projections is shared between customers and shareholders. Outside the ten-percent band, shareholders keep all of the benefit or pay all the cost.

The W&S Model incorporates actual market-based data by using the All Urban CPI index to adjust historic wages and salaries.[14] Notably, local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey.[15]

The Commission has concluded that adjusting payroll levels by changes in inflation provides the employees the same real level of compensation as in the base year, and provides an incentive to companies to minimize labor costs.[16] Further, sharing the difference between the two payroll projections equally between ratepayers and shareholders also allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.[17]

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[13] See Order 01-787 at 40; *In the Matter of Northwest Natural*, OPUC Docket UG 132, Order No. 99-697 at 43 (November 12, 1999); *In the Matter of PGE*, OPUC Docket UE 102, Order 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, OPUC Docket UE 88, Order No. 95-322 at10 (March 29, 1995).

[14] Id.

[15] Id.

[16] Order 01-787 at 40.

[17] Order No. 95-322 at 10.

Rather than using All-Urban CPI for union wages, the Commission in the past has ordered that union payroll increases be tied to negotiated wage increases as set forth in the union contract.[18] Staff applied this model to the information the Company provided in its filing and responses to Staff data requests.

For incentives, Commission policy is to disallow 100 percent of officers' bonuses, which are typically based on earnings.[19] It is also Commission policy to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders), and disallow 50 percent of merit-based bonuses (because they equally benefit shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses.[20]

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

A. The Company includes in the test year approximately $281.540 million in wages and salaries, $13.026 million in incentive compensation, and $21.086 million in overtime.[21]

Q. How do the Company's adjustments to salaries, wages and incentives differ from those Staff typically makes in a general rate case?

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[18] See Order No. 99-697 at 43.

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

[20] See Order 99-697 at 44-45; Order 99-033 at 62.

[21] These amounts are found in the Company's Excel spreadsheet, Total Compensation.xlsx, filed with Exhibit 400 electronic workpapers.

A. Staff explains the differences by each component of Staff's W&S model below.

Escalation

As explained in its testimony, PGE used rates of 3.50 percent and 4.00 percent derived from industry and marketing data to escalate its non-bargaining wages and salaries. The 2017 actuals were escalated by 3.50 percent to its 2018 budget year. The 2018 budget was then escalated by 4.00 percent for its 2019 test year. The Company escalated union wages in a similar manner using a rate of 2.5 percent and 3.00 percent for 2018 and 2019, respectively.[22]

Staff, consistent with Staff's W&S model, escalated the 2016 historical year to a projected 2018 using the All-Urban CPI (CPI).[23, 24] For union employees, Staff escalates based on the last contracted rate increase, which was provided by the Company in its response to Staff DR No. 94.[25] Accordingly Staff escalated 2016 to 2017 by 2.5 percent, 2017 to 2018 by 2.5 percent, and 2018 to 2019 by 3.0 percent. Staff then applied the sharing percentages to Staff's projected 2019 test year amounts.

If Staff's projection is less than the Company's test year amount, the sharing test allows the Company to share 50/50 the lesser of the difference between the Company's filed proposal and Staff's calculated projection, or a 10 percent band around Staff's calculated projection.[26] In this case, the Company's filed proposal was higher than Staff's calculated projection but the

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[22] PGE/400, Mersereau-Neitzke/16.
[23] See Staff electronic workpaper, UE 335 Exhibit 400 W&S Issue 3 CONF-Gardner.xlsx.
[24] Staff/403, Escalation.
[25] Staff/403, Gardner, PGE Response to Staff DR No. 94.
[26] See Staff electronic workpaper, UE 335 Exhibit 400 W&S Issue 3 CONF-Gardner.xlsx.

variance was less than the ten percent band. Therefore, Staff's adjustment is 50 percent of the difference between the Company's proposal and Staff's projection.

Q. What is Staff's recommendation regarding the escalation of salaries and wages to include in the 2019 test year?

A. Staff recommends reducing the test year compensation as follows:

- Salaries and wages by ($3.649) million allocated as ($2.492) million O&M expense and ($1.157) million capital;
- Incentives by ($4.774) million allocated as ($3.119) million O&M expense and ($1.356) million capital; and,
- Related payroll taxes by ($2.055) million and depreciation expense by ($297) thousand.[27]

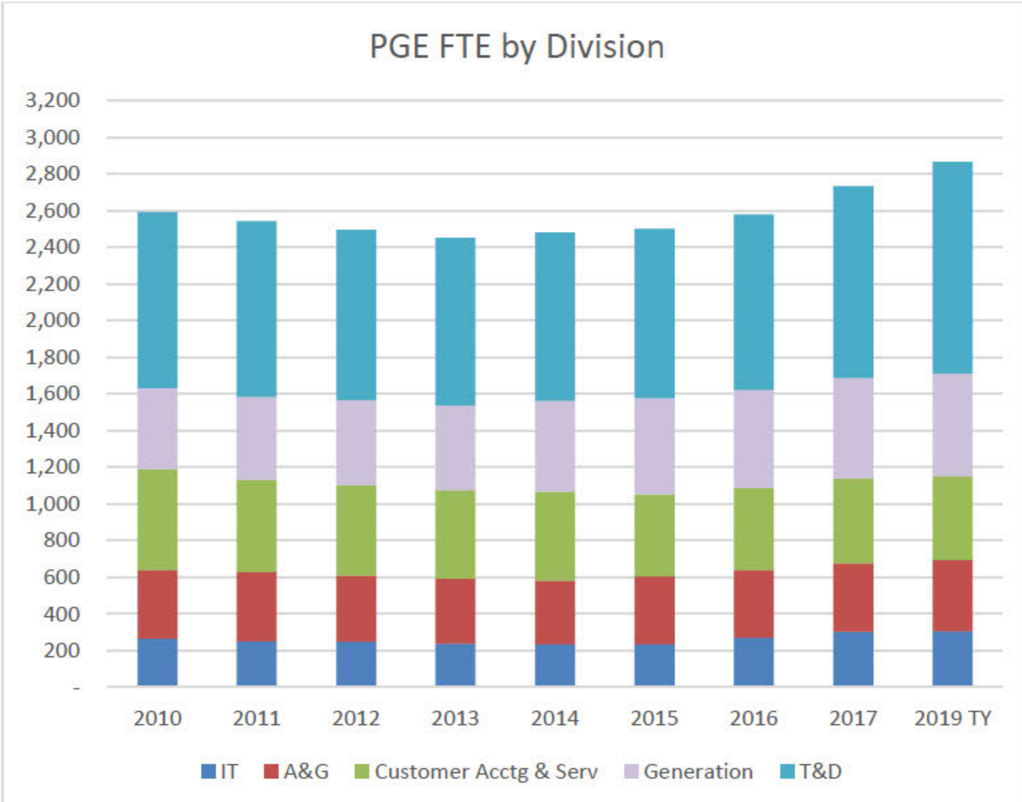
FTEs

Q. Please provide the background for this issue.

A. PGE's 2019 test year forecast includes costs of approximately 133 incremental FTEs over PGE's 2017 actual FTE count,[28] which is approximately a five percent increase in its workforce. The 2019 FTE forecast represents an increase of approximately 366 FTE or 13.4 percent over PGE's 2015 actual FTE count. The growth in PGE's FTE since 2010 is shown in the Chart D below.

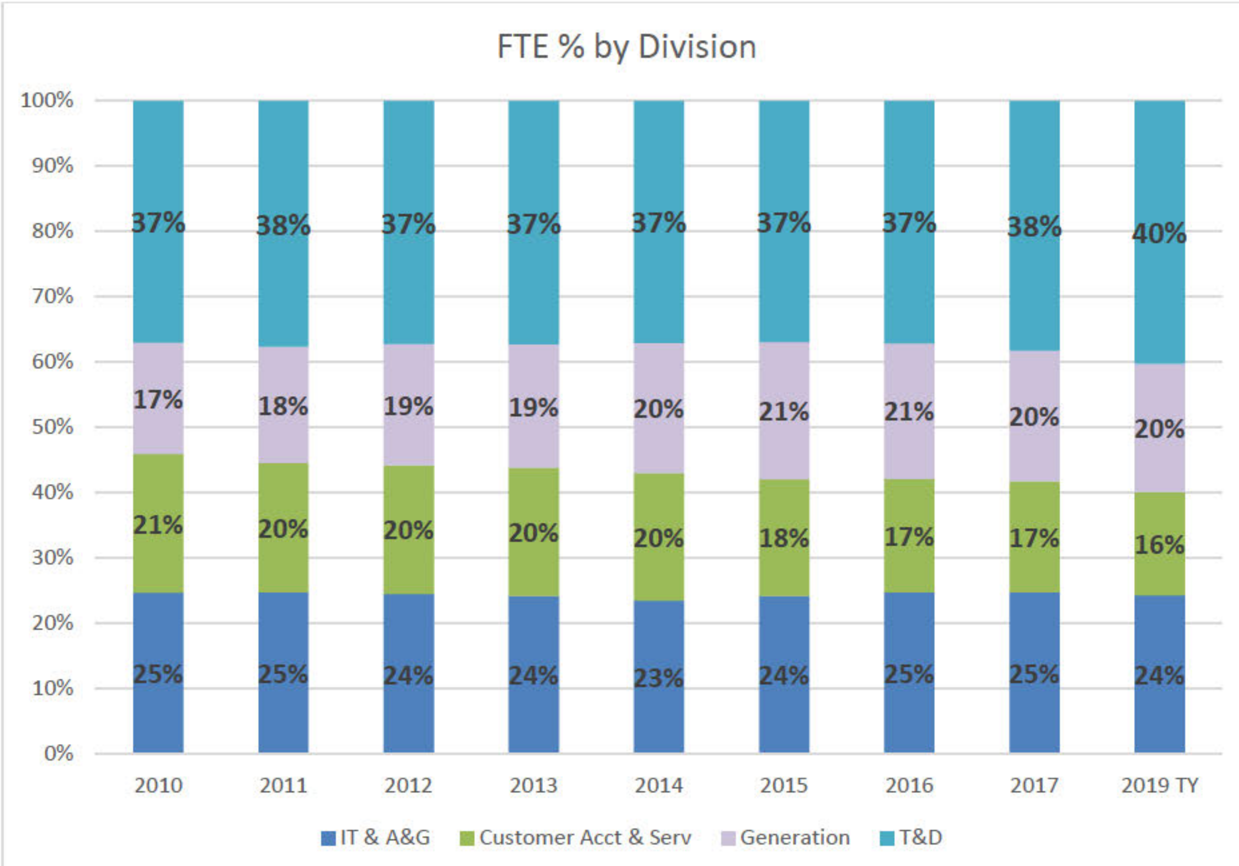
[27] Ibid.
[28] PGE/400, Mersereau-Neitzke/12.

Chart D



The concentration of FTE by Division is illustrated in Chart E below. As can be seen in the chart the percentage of T&D and Generation have grown a few percentage points over time while the support functions of A&G, IT, Customer Service, and Customer Accounting have gone down by a few percentage points.

Chart E



According to testimony, PGE plans to distribute the new FTEs as follows:

- A&G 17.2
- IT 2.4
- Cust Svc/Accts -9.4
- Generation 13.5
- T&D 109.2[29]

Q. Why is Staff concerned about the FTE increase?

A. Staff's concern is similar to that expressed in its testimony in Docket No. UE 319 when PGE proposed growing its FTE by 270 FTE from 2016 to its 2018 test year.[30] This does not include the 38 FTE accounted for in the CET

[29] PGE/400, Mersereau-Neitzke/13.
[30] UE 319 Staff/400, Gardner/37 at 15-19 and /38 at 1-23.

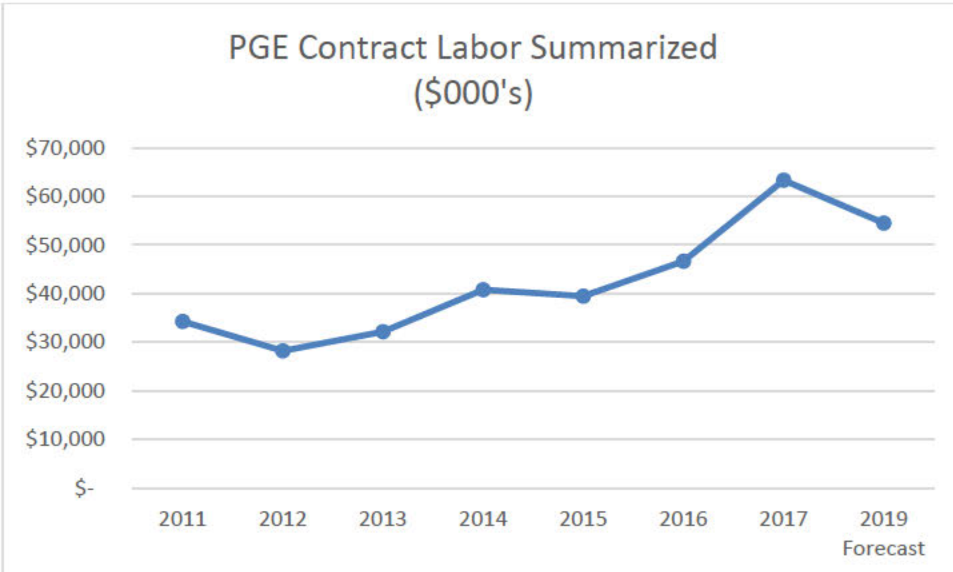
deferral. Staff finds this concerning because PGE has touted in testimony that it has implemented lean concepts and new systems that, among other benefits, have resulted in efficiencies.[31] For example, PGE states, "FSRP, in conjunction with Lean process analysis, allowed for Finance and Accounting (F&A) to realize efficiencies through a net reduction of approximately 11 Full Time Equivalents (FTE) through 2012 and another 4.3 FTEs by 2014."[32] However, from 2014 to 2017 PGE has added 24 FTE back to A&G and has proposed in this docket to add another 17 FTE from 2017 to the 2019 test year. A continuing pattern Staff has observed in PGE's prior two rate cases, Docket Nos. UE 294 and UE 319, and now in Docket No. UE 335 is that PGE adds and then reshuffles employees between divisions as its initiatives/projects like the CET end and others like the Cybersecurity start. So the net effect is that overall FTE grows but promised labor efficiencies fail to materialize.

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

A. No. Although PGE has testified that it is capitalizing more of its payroll costs because PGE's own FTE are supplanting contract labor, the actual contractor costs does not bear this assertion out.

[31] PGE /102, Pope – Lobdell/1.
[32] PGE/102, Pope – Lobdell/2.

Chart F

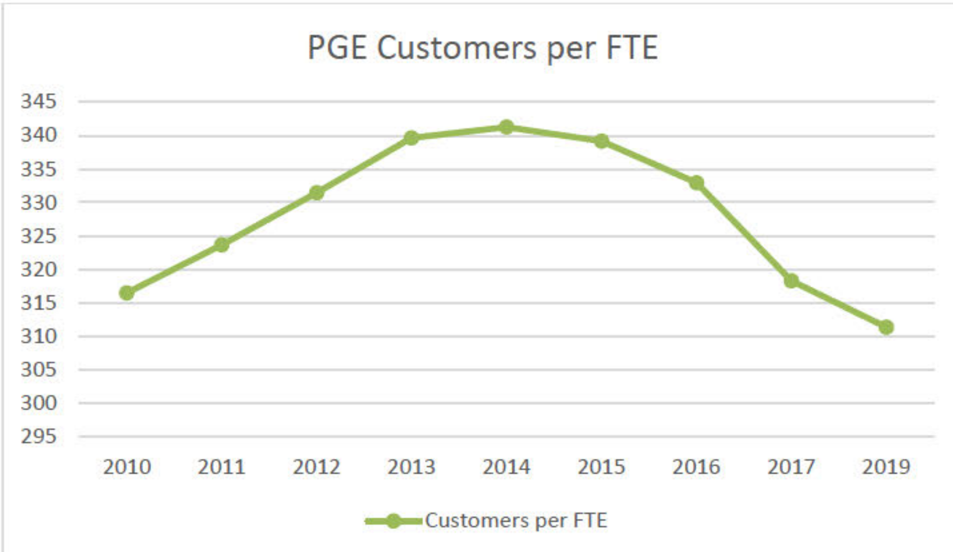


Q. What is the impact on customers?

A. Besides bearing the payroll costs, benefits, and other costs associated with additional FTE, customers have had to shoulder the O&M and capital costs of these projects and are not benefiting by a decrease in rates.[33,34] Also, as shown in Chart G, customer growth is not supporting the growth in FTE.

[33] Staff/800, Kaufman/21.
[34] Staff/800, Kaufman/29.

Chart G



Q. Besides being over-staffed on a per customer basis, does PGE have a history of over-budgeting?

A. Yes. In Docket No. UE 319, PGE budgeted 2789.8 FTE for 2017 but 2017 actuals are 2734.6 FTE or 55 less than budget.

Q. Does Staff propose an adjustment to the proposed 2019 test year FTE?

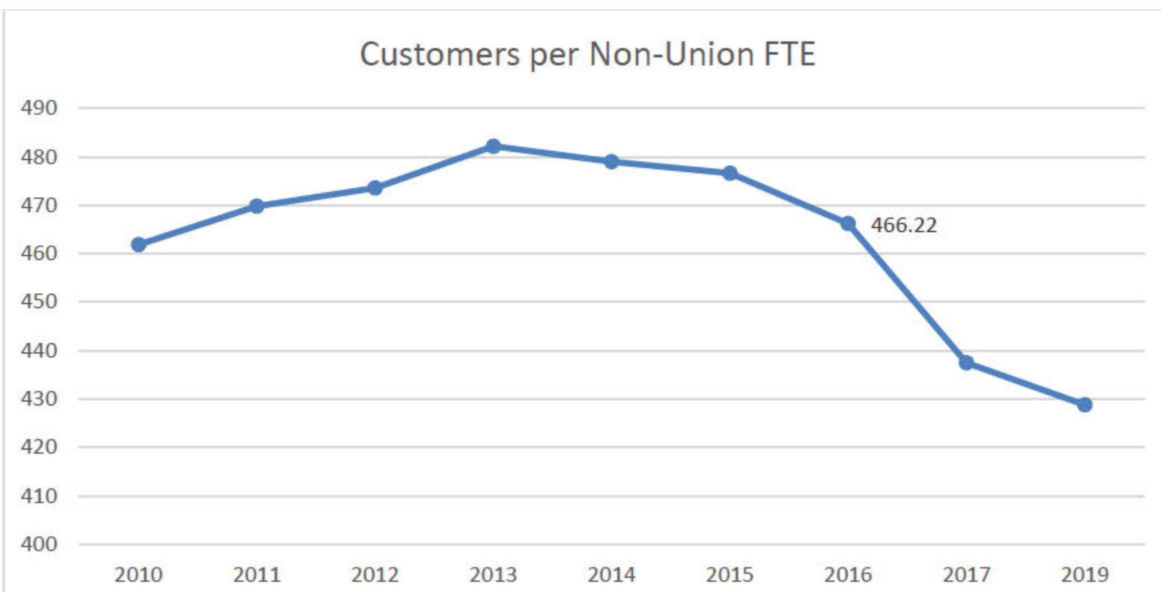
A. Yes. Staff did not identify specific job duties or assignments and propose an adjustment to FTE based on an evaluation of those positions. Rather, Staff is estimating a reasonable level of FTE. Using an estimate to adjust FTE levels rather than incrementally determining whether a particular position is essential is a method adopted by the Commission in PGE's 2009 GRC in Docket No. UE 197:

> We reject PGE's proposed incremental approach to calculating test-year FTEs. To do a proper analysis, we would have to evaluate all 2,600-plus positions in the Company and not just the incremental positions PGE proposes to add. We will not take the existing positions as a given without such an analysis. Nor do we find such an analysis practical or

> good policy. We adopt Staff's approach applying the historical growth rate in workforce levels. Ultimately, the Company may choose to hire whatever staff or fill whatever positions it feels is necessary.[35]

Staff has chosen to use a methodology consistent with the Commission's 2009 order in PGE's GRC. Staff recommends that the non-union work force should be limited to levels forecasted as a function of customers per FTE. Staff calculated the customers to non-union FTE from 2010 through the 2019 forecast. Staff graphed this data and has presented it in Chart H below. Staff also calculated the total average of customers to non-union FTE for this same period. This results in an average of 464 customers per FTE.

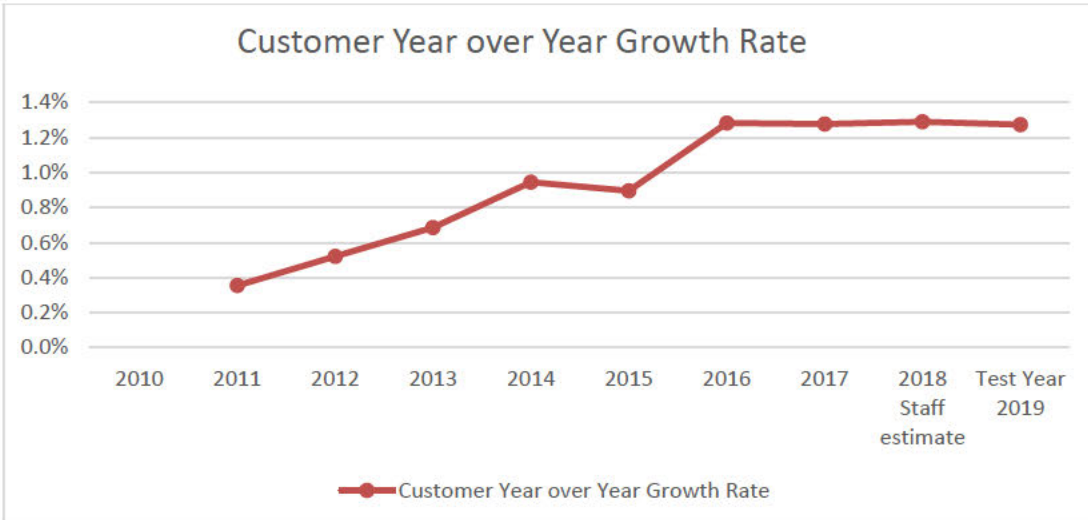
Chart H



[35] *In the Matter of Portland General Electric*, OPUC Docket UE 197, Order No. 09-020 at 6-7 (January 22, 2009).

Staff also notes in Chart I that from 2016 through 2019, the year over year customer growth has stayed flat at approximately 1.28 percent.[36]

Chart I



Based on reviewing Chart H, Staff believes that the 2016 customer per non-union ratio of 466 is representative for the trend from 2010 through 2016. As can be seen, the addition of FTE in 2016 causes the ratio of customers to non-union FTE to drop significantly to 428 customers per non-union FTE in the test year. Therefore, Staff proposes to adjust the non-union FTE of 2,082.3 for the test year back to the 2016 level of non-union FTE of 1,843.3. This results in a proposed reduction of 238.9 FTE.

With regards to union employees, Staff proposes to limit FTE levels to actual levels at a specified date.[37] For union employees, Staff proposes to limit

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[36] See Staff electronic workpaper, UE 335 Exhibit 400 W&S Issue 3 – Gardner.xlsx,
[37] Order No. 01-787 at 41-42.

the FTE to those employed as of October 31, 2018 as long as this count does not exceed the number of union FTE proposed by the Company for the test year. Since the number of FTE at October 31, 2018 is yet unknown, it is not included in Staff's calculation. However, Staff reserves the right to calculate an adjustment for union FTE.

Q. What is the amount of the adjustment that Staff has calculated for opening testimony?

A. Staff recommends distributing the proposed reduction of 238.9 FTE pro-rata between Exempt and Non-exempt employees[38] based on the 2019 test year. This results in a reduction of ($13.602) million dollars allocated ($9.290) million and ($4.312) million between O&M and capital, respectively.

Q. Does this conclude your testimony?

A. Yes.

[38] The most significant difference between Exempt and Non-exempt employees is pay for overtime. Exempt employees are usually excluded from minimum wage and are not entitled to overtime pay. Non-exempt employees are usually paid minimum wage and entitled to overtime pay. Regulations that govern Exempt and Non-exempt classifications and overtime pay are set in Federal and state law.

CASE: UE 335
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

June 6, 2018

WITNESS QUALIFICATION STATEMENT

NAME: Marianne Gardner

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Revenue Requirement Analyst
Energy Rates, Finance and Audit Division

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

EDUCATION: Master of Business Administration
Oregon State University, Corvallis, Oregon

Bachelor of Science in Accounting
Montana State University, Bozeman, Montana

CPA, Oregon

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since March 2013, with my current position being a Senior Revenue Requirement Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. As the revenue requirement summary witness, I have provided testimony in dockets UE 263, UG 246, UE 283, UE 294, UG 284, UG 287, UG 288, and UG 305.

I have approximately 20 years of professional accounting experience, including:

- Thirteen years as a cost accountant with responsibilities including cost accounting, budgeting, product costing, and the preparation of management reports;
- Four years experience in public accounting working in the areas of audit, tax and financial accounting for individual and small business clientele; and,
- Three years experience in non-profit accounting for an agency administrating funds under the Federal Job Training Partnership Act.

CASE: UE 335
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

REDACTED
June 6, 2018

May 24, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

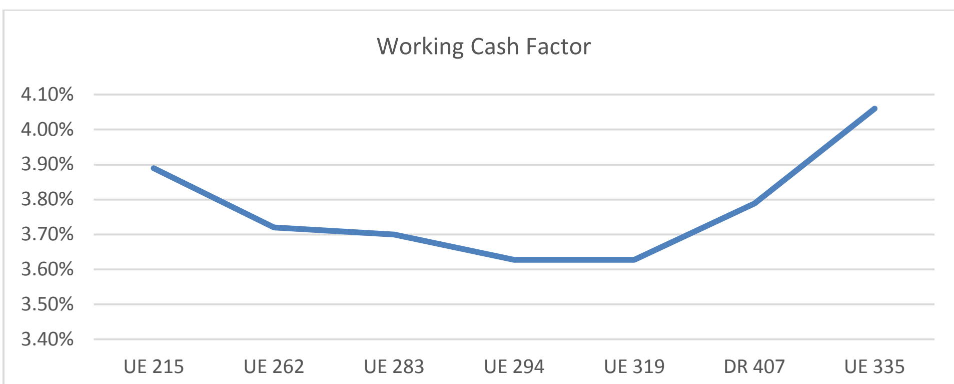
FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 312
Dated May 10, 2018

Request:

Referring to the Company's UE 335 workpaper, Working Cash Factor 2019_Lead-Lag.xlsx, and the Company's responses to UE 262 Staff DR No. 203, UE 283 Staff DR No. 283, and UE 319 Staff DR No. 407 please:

a. **Provide the lead/lag model referenced in the response to UE 319 DR No. 407, part b that was not utilized in UE 283 because the Company elected to use the rate of 3.628% previously approved in Order 15-356.**
b. **Explain why the most recent study provided in UE 335 results in a working cash factor of 4.06% that is much higher than those in prior rate cases as shown in the chart below.**



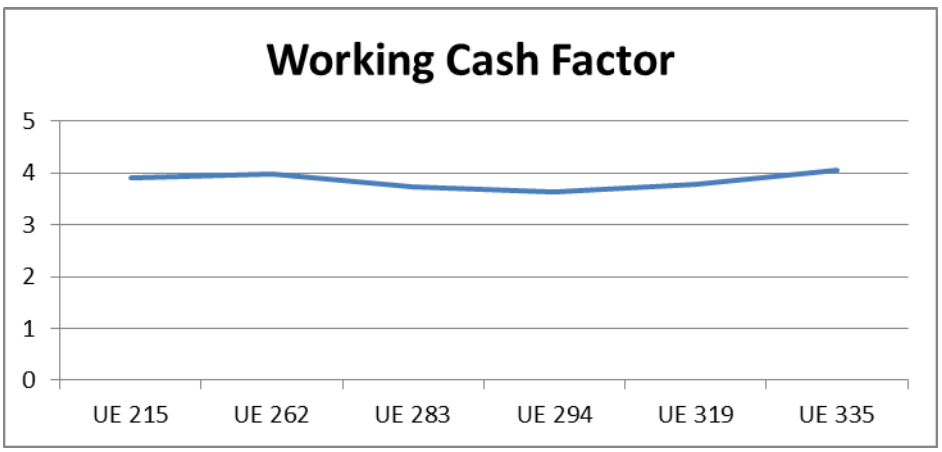
c. **Refer to Staff's Attachment A.xlsx and the Company's Working Cash Factor 2019_Lead-Lag.xlsx, and explain how the Company's methodology for calculating the UE 335 working cash factor differs from its methodology employed in UE 215, UE 262, and UE 283.**

d. Refer to Staff's Attachment A.xlsx and explain why the yellow highlighted areas in the UE 335 comparison differ significantly from UE 215, UE 262, and UE 283 studies.

Response:

a. See confidential Attachment 312-B - "New Lead/Lag Methodology". The working cash factor from this analysis (3.789%) is higher than the rate used in the 2018 test year forecast (UE 319; 3.628%). The UE 319 rate was originally developed for the 2016 test year forecast (UE 294).

b. There are numerous differences that contribute to the higher working cash factor in UE 335 from prior years' calculations as the working capital requirements for PGE's business changes every year. Among the most prominent items that changed from the prior year's calculations are the following: Lag Days on Revenues, Labor Lag days and Misc. O&M expenses.



Lag days for revenue had a very large effect on the overall working cash factor due to the large dollar weighting of the element. The lag days increased from 35.88 to 38.97, or just over three days. This increases revenue lag and increases the working cash factor for the current test year. Although this is a large increase from the UE 319 calculation, historically it is in line with prior year's revenue lag days as illustrated in the table below:

Case #	**UE 215**	**UE 262**	**UE 294**	**UE 319**	**UE 335**
Revenue Lag Days	**42.7**	**41.5**	**38.89**	**35.88**	**38.97**

Total labor expense Lag days decreased from 19.44 in UE 319 to 17.9 days in UE 335 as more and more employees used direct deposit. In prior years, when a check was issued for payroll, PGE would benefit from additional lag days until the check cleared the bank. Now, however, over 97% of all PGE employees are on direct deposit. Because of this, payroll funds are made available the night before the direct deposit enters the employees account. As seen in the table below, this large expense lag has been trending down for some time due to the shortened bank processing time for checks outstanding and a larger percentage of employees on direct deposit. This trend reduces PGE's expense lag and increases the working cash factor.

Case #	**UE 215**	**UE 262**	**UE 294**	**UE 319**	**UE 335**
Labor Lag Days	**25.5**	**22.8**	**18.6**	**19.44**	**17.86**

Misc. O&M expenses decreased by over 2 days from UE 319. This calculation was changed in 2015 due to Commission request tied to rate case UE 294 and currently includes applying the Lead/ Lag calculation for thousands of O&M payments for the year and applying that calculation to all of the Prepayments, Rents and Other Benefits categories that are measured in this category. By averaging the entire year's worth of O&M billings, PGE is paying vendors more quickly than in the prior two rate cases, which reduces our expense lag and increases the working cash factor for the current test year.

Case #	**UE 215**	**UE 262**	**UE 294**	**UE 319**	**UE 335**
Misc. O&M	**(12.1)**	**(10.9)**	**14.76**	**(3.18)**	**(5.45)**

It should also be noted that on the "Working Cash Factor" graph above that was supplied by Staff in the original DR, Staff incorrectly used a value of 3.63 for the calculation for the working cash factor for UE 319. The 3.63 value was the calculated value for UE 294. This value was also used in the *settlement* of UE 319 but was not the calculated value. The calculated working cash factor for UE 319 is 3.79. This is correctly stated in PGE's revised graph located at the beginning of section "above.

c. PGE followed the same overall methodology in UE 335 as in the preparation of UE 319. This model was also used in UE 294. See confidential Attachment 312-B labeled "New Lead/Lag Methodology" along with confidential Attachment 312-C labeled "Narrative Discussion of PGE Lead-Lag Study," which explains the 'New' methodology employed in the Lead-Lag Studies since 2015.

d. As discussed above in (c), PGE has changed its methodology as to how it calculates the Lead/Lag values. Because of this, a direct comparison of the calculations behind the values in UE 335's Lead/Lag study to results from UE 215, UE 262, and UE 283 can be explained by the Narrative Discussion of PGE Lead-Lag study referenced in (c) above. See also additional comments made on Staff's Attachment "A" the spreadsheet (highlighted in Green) for additional context.

Attachments 312-A, 312- B, and 312-C contain protected information and are subject to Protective Order 18-047

UE 335

Attachment 312-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Staff Analysis for Staff DR 312

UE 335

Attachment 312-B

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

New Lead/Lag Methodology

UE 335

Attachment 312-C

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Narrative Discussion of PGE Lead-Lag Study

February 15, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Standard Data Request No. 062
Dated February 15, 2018

Request:

Please provide a breakdown of the costs involved in the director's fees. Are any of these fees paid to directors who are also officers of the Company? Please explain. Also, please explain the type and method for any director compensation paid in stock (i.e., stock awards, stock options, etc.).

Response:

Only non-employee directors of the board may receive cash retainer, meeting, and/or chair fees. Attachment 062-A provides the estimated 2019 Board of Directors forecast and a comparison to the 2018 budget.

Each non-employee director receives a grant of restricted stock units. Each restricted stock unit represents the right to receive one share of common stock at a future date. Provided that the director remains a member of the board, the restricted stock units will vest over a one-year period in equal installments on the last day of each calendar quarter and will be settled exclusively in shares of common stock. Restricted stock units do not have voting rights with respect to the underlying common stock until the units vest and the common stock is issued. For 2017, board members active for the entire year were each granted 1,945 restricted stock units.

UE 335

Attachment 062-A

Provided in Electronic Format only

Estimated 2019 Board of Directors Forecast
As Compared to 2018 Budget

May 9, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 299
Dated April 25, 2018

Request:

Referring to the Company's responses OPUC_DR_062, and OPUC_DR_062_Attach A.xlsx, please supplement the responses and:

a. **Include the actual Board of Director Costs for 2017, the allocation to the Oregon regulated operations, and the transactional detail by FERC account and cost element for the 2017 actual Board of Director costs;**
b. **Provide, by FERC account, the amount of Board of Director costs included in the Oregon-allocated test year. If the amounts vary from the 2018 budget, please provide a detailed narrative;**
c. **Provide the breakdown of 2017 "Other Expenses" by cost type and:**
    i. **Explain whether the expenses and reimbursements for directors includes only the "Offsite Strategic Planning" meeting or does it include other meetings and, if so, describe the frequency, business nature, and location of those meetings;**
    ii. **Explain whether it includes any amounts for spouse, children, and significant others etc.;**
    iii. **What portion of the costs are for entertainment versus business, e.g. golfing, white water rafting, fishing; and,**
    iv. **Explain whether travel reimbursement includes the cost of using private airplanes. If so, please justify.**
d. **Explain where the "Offsite Strategic Planning" meeting was held in 2016 and 2017, and where it is planned to be held in 2018;**
e. **Explain and justify why board compensation is budgeted to increase by 10 percent for 2018;**

Response:

a. Attachment 299-A provides the requested 2017 actual cost information. Depending on the type of expense (e.g., annual committee fees and board chair retainers), the level of available detail varies between budgeted and actual costs.

b. Attachment 299-B provides the requested information. PGE applied a 2.54% rate to escalate the 2018 budget to the 2019 test year for business expenses. (This is the same rate as used for employee business expenses.)

c. Attachment 299-A provides the requested information.

   i. The expenses include offsite strategic planning retreats and four quarterly meetings in Portland, Oregon.

   ii. As a general rule, PGE does not reimburse travel expenses incurred by a Board of Director member's spouse, significant other, or children. However, in rare instances, PGE will make an exception to provide reimbursement if a member's spouse or partner is specifically invited to a company event. These expenses must be reasonable and well-documented. In addition, travel expenses related to a spouse or partner is treated as taxable income to the board member. PGE does not budget for travel expenses incurred by Board of Director members' spouses, significant others, or children, and did not include such costs in the test year forecast.

   iii. All costs are for business expenses.

   iv. Private airplanes are not included in PGE's travel expense reimbursement policy.

d. The 2016 meeting was held in Hillsboro, Oregon. The 2017 meeting was held in Washington, D.C. The 2018 meeting will be held in Portland, Oregon.

e. The primary drivers behind the increase in Director compensation for 2019 is three-fold. First, there are several directors that will be nearing or reaching the mandatory retirement age in 2019. Second to attract the skill and talent at the board of director level to replace these retiring directors we need to provide competitive compensation. Third, and the most important of the drivers, is attracting and retaining directors with experience in industries that are going through transformation and those that are skilled at technology and cyber security as well as bringing more diversity to the Board.

UE 335

Attachment 299-A

Provided in Electronic Format only

2017 Board of Director Costs

UE 335

Attachment 299-B

Provided in Electronic Format only

2019 Test Year Board of Director Costs

CASE: UE 335
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

June 6, 2018

APPENDIX A: ECONOMIC FORECAST DETAIL

Table A.1 – Employment Forecast Tracking

Total Nonfarm Employment, 4th quarter 2017
(Employment in thousands, Annualized Percent Change)

	Preliminary Estimate		Forecast		Forecast Error		Y/Y Change
	level	% ch	level	% ch	level	%	% ch
Total Nonfarm	1,884.9	1.4	1,894.2	2.8	(9.3)	(0.5)	2.0
Total Private	1,573.5	2.4	1,579.1	3.0	(5.6)	(0.4)	2.3
Mining and Logging	7.0	7.5	7.1	5.3	(0.1)	(0.7)	(2.4)
Construction	98.9	2.9	100.1	3.7	(1.2)	(1.2)	6.6
Manufacturing	190.9	2.9	191.2	1.5	(0.3)	(0.1)	1.5
Durable Goods	132.4	2.5	132.7	1.5	(0.3)	(0.2)	1.1
Wood Product	23.0	2.8	23.0	2.3	0.0	0.1	1.1
Metals and Machinery	37.6	5.1	37.4	1.7	0.2	0.6	2.7
Computer and Electronic Product	37.4	4.8	37.4	1.5	0.0	0.0	0.2
Transportation Equipment	11.7	(9.4)	12.0	1.7	(0.3)	(2.8)	(2.4)
Other Durable Goods	22.7	0.7	22.9	0.4	(0.2)	(0.9)	2.0
Nondurable Goods	58.5	4.0	58.5	1.6	0.0	0.0	2.4
Food	30.1	8.0	30.1	1.3	0.0	0.1	2.6
Other Nondurable Goods	28.4	(0.1)	28.4	1.9	0.0	0.0	2.1
Trade, Transportation & Utilities	349.7	(0.3)	352.8	1.7	(3.1)	(0.9)	1.4
Retail Trade	210.0	0.5	210.7	0.3	(0.7)	(0.4)	1.5
Wholesale Trade	75.9	(3.9)	77.5	3.1	(1.5)	(2.0)	(0.0)
Transportation, Warehousing & Utilities	63.7	1.6	64.6	4.4	(0.8)	(1.3)	2.6
Information	34.2	2.1	34.6	0.3	(0.4)	(1.0)	1.9
Financial Activities	99.2	2.2	99.8	5.0	(0.6)	(0.6)	1.8
Professional & Business Services	245.0	2.9	244.4	3.7	0.6	0.3	2.3
Educational & Health Services	274.7	1.4	277.5	5.0	(2.8)	(1.0)	2.2
Educational Services	36.4	(5.3)	36.3	(1.7)	0.2	0.5	2.5
Health Services	238.3	2.4	241.3	6.1	(3.0)	(1.2)	2.2
Leisure and Hospitality	210.0	7.5	208.2	2.9	1.7	0.8	3.9
Other Services	63.9	1.8	63.5	2.0	0.4	0.6	(0.7)
Government	311.4	(3.4)	315.1	1.7	(3.7)	(1.2)	0.9
Federal	28.1	(1.5)	28.2	0.5	(0.1)	(0.4)	(1.1)
State	57.3	(12.4)	56.8	(17.2)	0.5	0.9	0.5
State Education	0.9	(28.4)	0.8	(52.6)	0.1	8.8	(7.6)
Local	226.0	(1.2)	230.1	7.3	(4.1)	(1.8)	1.3
Local Education	132.0	(3.4)	137.8	17.7	(5.8)	(4.2)	0.9

Table A.2 – Short-Term Oregon Economic Summary

Oregon Forecast Summary

	Quarterly					Annual					
	2017:4	2018:1	2018:2	2018:3	2018:4	2016	2017	2018	2019	2020	2021
Personal Income ($ billions)											
Nominal Personal Income	196.2	198.8	201.8	204.8	207.6	185.8	192.6	203.2	214.9	226.3	237.3
% change	6.4	5.4	6.1	6.0	5.7	4.2	3.7	5.5	5.7	5.3	4.9
Real Personal Income (base year=20	173.0	174.8	177.0	179.0	180.8	167.7	171.0	177.9	185.0	190.7	195.8
% change	3.7	4.2	5.2	4.4	4.1	2.9	1.9	4.0	4.0	3.1	2.7
Nominal Wages and Salaries	102.5	103.9	105.7	107.4	109.0	96.0	100.2	106.5	113.1	118.8	124.3
% change	7.1	5.6	6.8	6.5	6.5	5.4	4.3	6.3	6.2	5.1	4.6
Other Indicators											
Per Capita Income ($1,000)	47.0	47.5	48.0	48.5	49.0	45.5	46.4	48.3	50.3	52.3	54.1
% change	4.9	4.1	4.6	4.2	4.3	2.6	2.1	4.0	4.3	3.9	3.6
Average Wage rate ($1,000)	53.7	54.3	54.9	55.5	56.0	51.9	53.0	55.2	57.4	59.7	62.1
% change	4.4	4.6	4.4	4.1	4.0	2.3	2.1	4.2	4.1	4.0	4.0
Population (Millions)	4.2	4.2	4.2	4.2	4.2	4.09	4.15	4.21	4.27	4.33	4.38
% change	1.4	1.3	1.5	1.7	1.3	1.5	1.6	1.5	1.4	1.3	1.3
Housing Starts (Thousands)	19.5	19.6	20.4	21.0	21.1	19.1	19.0	20.5	22.1	23.7	24.6
% change	(25.4)	2.2	17.2	11.1	3.4	19.8	(0.3)	8.1	7.7	7.2	3.7
Unemployment Rate	4.2	4.3	4.4	4.5	4.5	4.9	4.0	4.4	4.5	4.7	4.8
Point Change	0.2	0.0	0.2	0.1	0.0	(0.7)	(0.9)	0.4	0.1	0.1	0.1
Employment (Thousands)											
Total Nonfarm	1,884.9	1,895.3	1,906.5	1,917.6	1,928.9	1,833.5	1,872.8	1,912.1	1,952.2	1,972.9	1,983.9
% change	1.4	2.2	2.4	2.3	2.4	2.9	2.1	2.1	2.1	1.1	0.6
Private Nonfarm	1,573.5	1,583.0	1,592.8	1,602.7	1,612.8	1,526.3	1,562.0	1,597.8	1,633.1	1,648.9	1,657.8
% change	2.4	2.4	2.5	2.5	2.5	3.1	2.3	2.3	2.2	1.0	0.5
Construction	98.9	99.5	99.9	100.1	100.6	90.3	97.1	100.0	100.9	101.2	101.5
% change	2.9	2.3	1.5	0.9	2.1	8.5	7.5	3.0	0.9	0.3	0.3
Manufacturing	190.9	191.9	192.6	193.2	193.9	188.1	189.6	192.9	195.4	196.8	197.5
% change	2.9	2.1	1.4	1.4	1.3	1.0	0.8	1.8	1.3	0.7	0.4
Durable Manufacturing	132.4	133.1	133.6	134.0	134.5	131.2	131.5	133.8	135.5	136.4	136.6
% change	2.5	2.0	1.6	1.3	1.4	0.6	0.2	1.8	1.3	0.6	0.2
Wood Product Manufacturing	23.0	23.1	23.1	23.1	23.2	22.7	22.9	23.1	23.2	23.5	23.7
% change	2.8	1.4	0.1	(0.1)	1.3	1.0	0.9	0.8	0.5	1.2	0.7
High Tech Manufacturing	37.4	37.5	37.6	37.7	37.8	37.9	36.9	37.6	38.1	38.3	38.0
% change	4.8	0.9	1.1	1.1	1.5	0.4	(2.7)	2.0	1.4	0.3	(0.8)
Transportation Equipment	11.7	11.8	11.9	12.0	12.0	12.2	11.8	11.9	12.0	12.0	12.0
% change	(9.4)	5.1	2.2	1.8	1.5	(2.6)	(2.8)	0.9	1.0	(0.2)	(0.4)
Nondurable Manufacturing	58.5	58.9	59.0	59.2	59.4	56.9	58.1	59.1	59.9	60.4	60.9
% change	4.0	2.2	0.7	1.4	1.2	2.0	2.1	1.7	1.3	0.8	0.8
Private nonmanufacturing	1,382.6	1,391.0	1,400.2	1,409.4	1,418.9	1,338.2	1,372.4	1,404.9	1,437.8	1,452.2	1,460.4
% change	2.4	2.5	2.7	2.7	2.7	3.4	2.6	2.4	2.3	1.0	0.6
Retail Trade	210.0	210.7	211.4	211.9	212.5	205.9	210.2	211.6	213.9	215.2	215.7
% change	0.5	1.4	1.2	1.1	1.1	1.8	2.1	0.7	1.1	0.6	0.3
Wholesale Trade	75.9	76.5	76.9	77.4	77.7	75.6	76.5	77.1	78.2	78.7	79.0
% change	(3.9)	2.8	2.5	2.3	1.7	2.1	1.2	0.8	1.4	0.6	0.4
Information	34.2	34.4	34.6	34.7	34.9	33.5	34.2	34.6	35.1	35.4	35.5
% change	2.1	2.2	2.4	1.8	1.6	1.6	2.3	1.3	1.3	0.7	0.4
Professional and Business Services	245.0	248.2	251.7	255.4	259.5	238.2	243.3	253.7	268.9	277.2	281.8
% change	2.9	5.4	5.8	5.9	6.6	3.9	2.1	4.3	6.0	3.1	1.7
Health Services	238.3	240.0	241.7	243.4	245.1	230.4	236.4	242.6	248.9	251.7	254.4
% change	2.4	2.9	2.9	2.9	2.8	3.5	2.6	2.6	2.6	1.1	1.1
Leisure and Hospitality	210.0	210.4	211.4	212.6	213.3	199.8	206.3	211.9	214.7	214.5	213.3
% change	7.5	0.8	2.0	2.2	1.4	4.3	3.3	2.7	1.3	(0.1)	(0.5)
Government	311.4	312.4	313.7	314.9	316.1	307.2	310.8	314.3	319.0	324.0	326.1
% change	(3.4)	1.3	1.6	1.6	1.5	2.0	1.2	1.1	1.5	1.6	0.6

Table A.3 – Oregon Economic Forecast Change

Oregon Forecast Change (Current vs. Last)

	Quarterly					Annual					
	2017:4	2018:1	2018:2	2018:3	2018:4	2016	2017	2018	2019	2020	2021
				Personal Income ($ billions)							
Nominal Personal Income	196.2	198.8	201.8	204.8	207.6	185.8	192.6	203.2	214.9	226.3	237.3
% change	(0.2)	(0.3)	(0.1)	0.1	0.2	0.0	(0.1)	(0.0)	0.3	0.1	0.1
Real Personal Income (base year=20(	173.0	174.8	177.0	179.0	180.8	167.7	171.0	177.9	185.0	190.7	195.8
% change	(0.5)	(0.5)	(0.2)	0.1	0.2	0.0	(0.2)	(0.1)	0.3	0.1	(0.1)
Nominal Wages and Salaries	102.5	103.9	105.7	107.4	109.0	96.0	100.2	106.5	113.1	118.8	124.3
% change	(0.6)	(0.8)	(0.7)	(0.5)	(0.4)	0.0	(0.1)	(0.6)	(0.2)	(0.4)	(0.7)
				Other Indicators							
Per Capita Income ($1,000)	47.0	47.5	48.0	48.5	49.0	45.5	46.4	48.3	50.3	52.3	54.1
% change	(0.2)	(0.3)	(0.1)	0.1	0.2	0.0	(0.1)	(0.0)	0.3	0.1	0.1
Average Wage rate ($1,000)	53.7	54.3	54.9	55.5	56.0	51.9	53.0	55.2	57.4	59.7	62.1
% change	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	0.0	(0.1)	(0.3)	(0.4)	(0.6)	(0.7)
Population (Millions)	4.17	4.19	4.20	4.2	4.2	4.09	4.15	4.21	4.27	4.33	4.38
% 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)	19.5	19.6	20.4	21.0	21.1	19.1	19.0	20.5	22.1	23.7	24.6
% change	(3.1)	(9.5)	(9.0)	(8.7)	(6.9)	(0.0)	(0.9)	(8.5)	(4.0)	(1.0)	0.1
Unemployment Rate	4.2	4.3	4.4	4.5	4.5	4.9	4.0	4.4	4.5	4.7	4.8
Point Change	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
				Employment (Thousands)							
Total Nonfarm	1,884.9	1,895.3	1,906.5	1,917.6	1,928.9	1,833.5	1,872.8	1,912.1	1,952.2	1,972.9	1,983.9
% change	(0.5)	(0.4)	(0.3)	(0.3)	(0.1)	(0.0)	(0.2)	(0.3)	0.2	0.2	0.0
Private Nonfarm	1,573.5	1,583.0	1,592.8	1,602.7	1,612.8	1,526.3	1,562.0	1,597.8	1,633.1	1,648.9	1,657.8
% change	(0.4)	(0.3)	(0.1)	(0.1)	0.1	0.0	(0.1)	(0.1)	0.5	0.5	0.3
Construction	98.9	99.5	99.9	100.1	100.6	90.3	97.1	100.0	100.9	101.2	101.5
% change	(1.2)	(0.3)	0.3	0.3	0.7	(0.0)	(0.6)	0.2	0.7	0.6	0.6
Manufacturing	190.9	191.9	192.6	193.2	193.9	188.1	189.6	192.9	195.4	196.8	197.5
% change	(0.1)	0.0	(0.1)	(0.0)	0.1	(0.0)	(0.2)	0.0	0.4	0.6	0.4
Durable Manufacturing	132.4	133.1	133.6	134.0	134.5	131.2	131.5	133.8	135.5	136.4	136.6
% change	(0.2)	(0.0)	0.1	0.1	0.3	0.0	(0.2)	0.1	0.7	1.1	0.9
Wood Product Manufacturing	23.0	23.1	23.1	23.1	23.2	22.7	22.9	23.1	23.2	23.5	23.7
% change	0.1	0.4	0.2	0.2	0.5	0.0	(0.0)	0.3	0.3	0.7	0.7
High Tech Manufacturing	37.4	37.5	37.6	37.7	37.8	37.9	36.9	37.6	38.1	38.3	38.0
% change	0.0	(0.1)	(0.3)	(0.4)	(0.4)	(0.0)	(0.2)	(0.3)	0.7	1.4	1.1
Transportation Equipment	11.7	11.8	11.9	12.0	12.0	12.2	11.8	11.9	12.0	12.0	12.0
% change	(2.8)	(1.8)	(1.6)	(1.7)	(1.7)	0.0	(0.7)	(1.7)	(1.6)	(2.0)	(2.9)
Nondurable Manufacturing	58.5	58.9	59.0	59.2	59.4	56.9	58.1	59.1	59.9	60.4	60.9
% change	0.0	0.1	(0.3)	(0.3)	(0.4)	(0.0)	(0.2)	(0.2)	(0.3)	(0.4)	(0.7)
Private nonmanufacturing	1,382.6	1,391.0	1,400.2	1,409.4	1,418.9	1,338.2	1,372.4	1,404.9	1,437.8	1,452.2	1,460.4
% change	(0.4)	(0.3)	(0.2)	(0.1)	0.1	0.0	(0.1)	(0.1)	0.5	0.5	0.3
Retail Trade	210.0	210.7	211.4	211.9	212.5	205.9	210.2	211.6	213.9	215.2	215.7
% change	(0.4)	(0.1)	0.1	0.2	0.4	0.0	(0.2)	0.1	0.6	0.5	0.4
Wholesale Trade	75.9	76.5	76.9	77.4	77.7	75.6	76.5	77.1	78.2	78.7	79.0
% change	(2.0)	(1.6)	(1.3)	(0.9)	(0.7)	0.0	(0.6)	(1.1)	(0.2)	(0.0)	0.0
Information	34.2	34.4	34.6	34.7	34.9	33.5	34.2	34.6	35.1	35.4	35.5
% change	(1.0)	(0.5)	(0.0)	0.2	0.4	0.0	(0.7)	(0.0)	0.7	0.6	0.5
Professional and Business Services	245.0	248.2	251.7	255.4	259.5	238.2	243.3	253.7	268.9	277.2	281.8
% change	0.3	0.4	0.5	0.8	1.0	0.0	0.2	0.7	1.2	1.2	0.7
Health Services	238.3	240.0	241.7	243.4	245.1	230.4	236.4	242.6	248.9	251.7	254.4
% change	(1.2)	(1.1)	(1.1)	(1.2)	(0.9)	0.0	(0.4)	(1.1)	0.1	0.3	0.0
Leisure and Hospitality	210.0	210.4	211.4	212.6	213.3	199.8	206.3	211.9	214.7	214.5	213.3
% change	0.8	0.3	0.4	0.4	0.4	(0.0)	0.1	0.4	0.6	0.6	0.5
Government	311.4	312.4	313.7	314.9	316.1	307.2	310.8	314.3	319.0	324.0	326.1
% change	(1.2)	(1.3)	(1.4)	(1.4)	(1.4)	(0.0)	(0.3)	(1.4)	(1.3)	(1.2)	(1.3)

Table A.4 – Annual Economic Forecast

Mar 2018 - Personal Income

(Billions of Current Dollars)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Personal Income*												
Oregon	185.8	192.6	203.2	214.9	226.3	237.3	248.9	260.6	273.3	286.5	300.6	315.2
% Ch	4.2	3.7	5.5	5.7	5.3	4.9	4.9	4.7	4.9	4.8	4.9	4.9
U.S.	15,928.7	16,415.9	17,132.9	18,031.3	18,933.8	19,795.8	20,663.3	21,582.5	22,521.1	23,490.3	24,504.6	25,561.6
% Ch	2.4	3.1	4.4	5.2	5.0	4.6	4.4	4.4	4.3	4.3	4.3	4.3
Wage and Salary												
Oregon	96.0	100.2	106.5	113.1	118.8	124.3	129.9	135.9	142.5	149.5	156.9	164.5
% Ch	5.4	4.3	6.3	6.2	5.1	4.6	4.6	4.6	4.9	4.9	4.9	4.9
U.S.	8,085.2	8,338.6	8,709.2	9,184.0	9,630.7	10,051.4	10,494.5	10,968.2	11,475.8	12,002.4	12,556.4	13,140.7
% Ch	2.9	3.1	4.4	5.5	4.9	4.4	4.4	4.5	4.6	4.6	4.6	4.7
Other Labor Income												
Oregon	22.2	23.2	24.1	25.0	26.0	27.1	28.3	29.4	30.7	32.0	33.4	34.7
% Ch	5.0	4.6	3.9	3.7	4.2	4.3	4.2	4.1	4.2	4.3	4.2	4.0
U.S.	1,309.8	1,345.9	1,383.2	1,426.9	1,475.7	1,524.3	1,575.1	1,629.3	1,686.0	1,744.5	1,804.3	1,866.1
% Ch	2.5	2.8	2.8	3.2	3.4	3.3	3.3	3.4	3.5	3.5	3.4	3.4
Nonfarm Proprietor's Income												
Oregon	14.3	15.0	15.7	16.4	16.9	17.4	18.1	18.8	19.5	20.2	21.1	22.0
% Ch	9.5	4.8	4.5	4.3	3.4	2.6	3.9	3.9	3.7	3.9	4.2	4.2
U.S.	1,298.7	1,349.7	1,403.4	1,456.9	1,498.6	1,533.0	1,575.5	1,622.5	1,666.2	1,714.3	1,760.2	1,817.1
% Ch	2.7	3.9	4.0	3.8	2.9	2.3	2.8	3.0	2.7	2.9	2.7	3.2
Dividend, Interest and Rent												
Oregon	36.8	38.1	40.3	42.6	45.1	47.7	50.2	52.5	54.7	56.9	59.3	61.7
% Ch	1.8	3.5	5.9	5.6	6.0	5.7	5.1	4.6	4.2	4.0	4.2	4.0
U.S.	3,085.1	3,185.7	3,343.7	3,513.6	3,716.2	3,924.1	4,116.3	4,296.9	4,471.2	4,648.2	4,847.8	5,048.1
% Ch	1.2	3.3	5.0	5.1	5.8	5.6	4.9	4.4	4.1	4.0	4.3	4.1
Transfer Payments												
Oregon	36.6	37.2	38.8	41.1	43.6	46.2	48.9	51.8	55.0	58.3	61.8	65.6
% Ch	2.4	1.6	4.2	5.9	6.2	5.9	5.9	5.9	6.2	6.1	6.0	6.1
U.S.	2,722.1	2,819.5	2,961.1	3,121.3	3,301.1	3,497.4	3,714.1	3,946.3	4,197.8	4,464.3	4,739.3	5,023.8
% Ch	3.6	3.6	5.0	5.4	5.8	5.9	6.2	6.3	6.4	6.3	6.2	6.0
Contributions for Social Security												
Oregon	16.7	17.6	18.5	19.4	20.4	21.3	22.3	23.4	24.7	25.9	27.2	28.4
% Ch	4.6	5.3	4.9	5.1	5.0	4.8	4.5	5.1	5.2	5.1	4.8	4.7
U.S.	661.7	691.3	718.1	749.5	783.2	815.7	850.5	888.1	928.6	970.8	1,015.2	1,062.3
% Ch	3.9	4.5	3.9	4.4	4.5	4.1	4.3	4.4	4.6	4.5	4.6	4.6
Residence Adjustment												
Oregon	(3.9)	(4.1)	(4.2)	(4.3)	(4.4)	(4.5)	(4.6)	(4.7)	(4.8)	(5.0)	(5.1)	(5.3)
% Ch	5.6	3.4	2.8	2.6	2.4	2.3	2.0	2.2	2.9	3.0	2.7	3.2
Farm Proprietor's Income												
Oregon	0.5	0.6	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4
% Ch	(40.9)	11.9	(18.9)	5.1	1.9	(7.3)	(10.6)	0.8	2.9	1.6	1.4	1.6
Per Capita Income (Thousands of $)												
Oregon	45.5	46.4	48.3	50.3	52.3	54.1	56.1	58.1	60.2	62.5	64.8	67.3
% Ch	2.6	2.1	4.0	4.3	3.9	3.6	3.6	3.5	3.7	3.7	3.8	3.8
U.S.	49.2	50.4	52.2	54.5	56.7	58.9	61.0	63.2	65.5	67.8	70.2	72.7
% Ch	1.7	2.3	3.5	4.4	4.2	3.7	3.6	3.7	3.6	3.5	3.6	3.6

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

Mar 2018 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Nonfarm												
Oregon	1,833.5	1,872.8	1,912.1	1,952.2	1,972.9	1,983.9	1,994.6	2,004.9	2,017.6	2,031.8	2,045.5	2,058.1
% Ch	2.9	2.1	2.1	2.1	1.1	0.6	0.5	0.5	0.6	0.7	0.7	0.6
U.S.	144.3	146.5	148.8	151.0	152.1	152.4	153.1	153.8	154.4	155.0	155.6	156.2
% Ch	1.8	1.5	1.6	1.5	0.7	0.3	0.4	0.5	0.4	0.4	0.4	0.4
Private Nonfarm												
Oregon	1,526.3	1,562.0	1,597.8	1,633.1	1,648.9	1,657.8	1,665.2	1,672.6	1,682.4	1,693.3	1,703.3	1,711.9
% Ch	3.1	2.3	2.3	2.2	1.0	0.5	0.4	0.4	0.6	0.7	0.6	0.5
U.S.	122.1	124.1	126.3	128.4	129.1	129.4	129.9	130.4	130.9	131.3	131.8	132.2
% Ch	1.9	1.7	1.8	1.6	0.6	0.3	0.4	0.4	0.4	0.3	0.3	0.3
Mining and Logging												
Oregon	7.5	7.0	7.2	7.3	7.4	7.5	7.6	7.6	7.7	7.7	7.8	7.8
% Ch	(2.9)	(7.7)	3.2	2.2	1.3	1.0	0.9	0.7	0.6	0.8	0.6	0.5
U.S.	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
% Ch	(16.6)	4.6	4.8	2.9	3.3	2.2	1.5	1.2	1.0	0.0	(1.0)	(0.8)
Construction												
Oregon	90.3	97.1	100.0	100.9	101.2	101.5	101.8	102.2	102.4	103.0	103.9	105.0
% Ch	8.5	7.5	3.0	0.9	0.3	0.3	0.3	0.4	0.2	0.6	0.8	1.1
U.S.	6.7	6.9	7.0	7.3	7.6	7.8	7.9	8.1	8.2	8.4	8.5	8.6
% Ch	3.9	2.8	1.8	3.6	3.9	2.6	2.4	2.0	1.8	1.7	1.4	1.4
Manufacturing												
Oregon	188.1	189.6	192.9	195.4	196.8	197.5	198.1	198.6	199.5	200.6	201.8	203.0
% Ch	1.0	0.8	1.8	1.3	0.7	0.4	0.3	0.3	0.4	0.6	0.6	0.6
U.S.	12.3	12.4	12.7	12.9	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.1
% Ch	0.1	0.7	2.1	1.6	0.9	(0.0)	(0.2)	(0.1)	(0.0)	0.2	0.4	0.2
Durable Manufacturing												
Oregon	131.2	131.5	133.8	135.5	136.4	136.6	136.7	136.8	137.1	137.6	138.2	138.7
% Ch	0.6	0.2	1.8	1.3	0.6	0.2	0.1	0.1	0.2	0.4	0.4	0.4
U.S.	7.7	7.8	8.0	8.1	8.2	8.2	8.2	8.2	8.2	8.2	8.3	8.3
% Ch	(0.6)	0.5	2.6	2.0	1.2	0.1	(0.2)	(0.1)	(0.0)	0.3	0.7	0.5
Wood Products												
Oregon	22.7	22.9	23.1	23.2	23.5	23.7	23.7	23.8	24.0	24.0	24.1	24.2
% Ch	1.0	0.9	0.8	0.5	1.2	0.7	0.3	0.4	0.5	0.4	0.2	0.2
U.S.	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5
% Ch	2.5	0.7	3.2	6.0	4.1	2.8	2.7	3.0	2.7	2.0	2.0	1.6
Metal and Machinery												
Oregon	36.7	37.2	38.2	38.9	39.3	39.4	39.4	39.6	39.8	40.2	40.5	40.8
% Ch	(0.5)	1.4	2.8	1.8	0.9	0.4	0.1	0.4	0.7	0.9	0.8	0.6
U.S.	2.9	2.9	3.0	3.1	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3
% Ch	(3.0)	1.2	3.6	2.6	1.7	0.4	0.6	1.0	1.0	0.8	0.8	0.2
Computer and Electronic Products												
Oregon	37.9	36.9	37.6	38.1	38.3	38.0	37.8	37.5	37.3	37.2	37.1	37.1
% Ch	0.4	(2.7)	2.0	1.4	0.3	(0.8)	(0.5)	(0.7)	(0.5)	(0.3)	(0.1)	(0.1)
U.S.	1.0	1.0	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
% Ch	(0.5)	(0.6)	3.7	2.7	0.8	0.1	0.5	0.2	0.3	0.2	(0.2)	(0.6)
Transportation Equipment												
Oregon	12.2	11.8	11.9	12.0	12.0	12.0	11.9	11.9	11.9	11.9	11.9	11.9
% Ch	(2.6)	(2.8)	0.9	1.0	(0.2)	(0.4)	(0.3)	(0.2)	(0.3)	(0.1)	0.0	0.4
U.S.	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.5	1.5	1.4	1.5	1.5
% Ch	1.3	(0.6)	0.9	0.2	0.4	(1.6)	(3.4)	(3.6)	(3.4)	(1.0)	0.9	1.7
Other Durables												
Oregon	21.8	22.7	22.9	23.2	23.3	23.6	23.8	24.0	24.1	24.3	24.6	24.8
% Ch	4.3	4.0	1.1	1.1	0.6	1.1	1.0	0.7	0.7	0.9	0.9	1.0
U.S.	2.2	2.2	2.2	2.3	2.3	2.3	2.3	2.4	2.4	2.4	2.4	2.4
% Ch	1.3	1.0	2.2	1.9	1.3	0.6	0.7	0.7	0.6	0.6	0.8	0.6
Nondurable Manufacturing												
Oregon	56.9	58.1	59.1	59.9	60.4	60.9	61.4	61.8	62.3	63.0	63.7	64.2
% Ch	2.0	2.1	1.7	1.3	0.8	0.8	0.9	0.7	0.8	1.1	1.0	0.9
U.S.	4.6	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
% Ch	1.3	0.9	1.3	0.9	0.4	(0.2)	(0.2)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)
Food Manufacturing												
Oregon	29.1	29.8	30.3	30.9	31.1	31.4	31.7	31.8	32.0	32.4	32.7	33.1
% Ch	3.1	2.5	1.7	1.9	0.7	1.0	0.8	0.4	0.7	1.0	1.1	1.1
U.S.	1.6	1.6	1.6	1.7	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.9
% Ch	2.8	2.7	2.3	2.7	1.5	1.1	1.2	1.6	1.5	1.3	1.2	1.0
Other Nondurable												
Oregon	27.8	28.3	28.8	29.0	29.3	29.4	29.7	30.0	30.3	30.6	30.9	31.2
% Ch	0.8	1.8	1.7	0.7	1.0	0.6	0.9	1.0	1.0	1.1	1.0	0.8
U.S.	3.1	3.1	3.1	3.1	3.1	3.1	3.0	3.0	3.0	2.9	2.9	2.9
% Ch	0.5	0.0	0.8	(0.1)	(0.3)	(0.9)	(1.0)	(0.9)	(1.0)	(0.9)	(0.9)	(0.9)
Trade, Transportation, and Utilities												
Oregon	342.3	349.8	353.3	357.9	360.0	361.1	361.7	361.9	361.6	361.4	361.6	361.8
% Ch	2.1	2.2	1.0	1.3	0.6	0.3	0.2	0.1	(0.1)	(0.1)	0.1	0.1
U.S.	27.2	27.4	27.6	27.7	27.6	27.4	27.2	27.0	26.8	26.7	26.6	26.6
% Ch	1.3	0.6	0.8	0.4	(0.5)	(0.8)	(0.8)	(0.8)	(0.7)	(0.4)	(0.1)	(0.1)

Mar 2018 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Retail Trade												
Oregon	205.9	210.2	211.6	213.9	215.2	215.7	216.1	216.5	216.2	215.9	216.0	216.1
% Ch	1.8	2.1	0.7	1.1	0.6	0.3	0.2	0.1	(0.1)	(0.1)	0.1	0.0
U.S.	15.8	15.8	15.8	15.9	15.7	15.5	15.4	15.2	15.1	15.0	15.0	15.0
% Ch	1.4	0.1	0.0	0.0	(0.7)	(1.2)	(1.1)	(1.0)	(0.9)	(0.5)	(0.3)	0.0
Wholesale Trade												
Oregon	75.6	76.5	77.1	78.2	78.7	79.0	79.2	79.2	79.1	79.2	79.2	79.1
% Ch	2.1	1.2	0.8	1.4	0.6	0.4	0.2	0.0	(0.1)	0.1	0.0	(0.0)
U.S.	5.9	5.9	6.0	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.0	6.0
% Ch	0.2	1.0	1.5	1.1	0.1	0.1	(0.1)	(0.1)	(0.1)	(0.2)	(0.3)	(0.3)
Transportation and Warehousing, and Utilities												
Oregon	60.8	63.1	64.6	65.8	66.2	66.3	66.4	66.3	66.3	66.3	66.4	66.6
% Ch	3.0	3.9	2.4	1.9	0.5	0.2	0.1	(0.1)	(0.1)	0.1	0.2	0.2
U.S.	5.5	5.6	5.7	5.8	5.8	5.7	5.7	5.6	5.6	5.6	5.6	5.6
% Ch	2.2	1.6	2.0	0.7	(0.4)	(0.6)	(0.7)	(0.7)	(0.7)	(0.1)	0.3	(0.2)
Information												
Oregon	33.5	34.2	34.6	35.1	35.4	35.5	35.6	35.7	35.7	35.8	35.9	35.9
% Ch	1.6	2.3	1.3	1.3	0.7	0.4	0.3	0.1	0.1	0.3	0.2	0.1
U.S.	2.8	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
% Ch	0.8	(1.8)	(1.4)	1.8	1.4	1.2	0.7	0.0	(0.0)	(0.2)	(0.6)	(0.9)
Financial Activities												
Oregon	96.7	98.8	100.9	102.7	103.1	103.2	103.3	103.4	103.3	103.2	103.0	102.9
% Ch	2.0	2.2	2.1	1.8	0.4	0.2	0.1	0.1	(0.0)	(0.1)	(0.2)	(0.1)
U.S.	8.3	8.4	8.6	8.7	8.7	8.7	8.7	8.7	8.7	8.6	8.6	8.6
% Ch	2.0	1.9	1.3	1.2	0.5	0.2	(0.2)	(0.2)	(0.3)	(0.4)	(0.4)	(0.5)
Professional and Business Services												
Oregon	238.2	243.3	253.7	268.9	277.2	281.8	285.1	288.9	293.8	298.0	300.7	302.1
% Ch	3.9	2.1	4.3	6.0	3.1	1.7	1.2	1.3	1.7	1.4	0.9	0.5
U.S.	20.1	20.7	21.5	22.5	22.9	23.2	23.7	24.3	24.7	25.1	25.4	25.6
% Ch	2.6	2.9	3.6	4.9	1.9	1.2	2.2	2.3	1.9	1.5	1.3	0.8
Education and Health Services												
Oregon	266.1	272.6	279.0	285.5	288.6	291.6	294.5	297.4	301.0	305.1	309.2	312.6
% Ch	3.2	2.4	2.4	2.3	1.1	1.0	1.0	1.0	1.2	1.4	1.3	1.1
U.S.	22.6	23.1	23.5	23.8	23.8	23.8	23.9	23.9	24.1	24.2	24.4	24.6
% Ch	2.7	2.2	1.9	1.0	(0.1)	0.1	0.3	0.3	0.4	0.6	0.7	0.9
Educational Services												
Oregon	35.7	36.2	36.5	36.6	36.9	37.1	37.3	37.4	37.5	37.7	37.7	37.8
% Ch	1.2	1.3	0.8	0.5	0.7	0.6	0.5	0.2	0.3	0.4	0.1	0.2
U.S.	3.6	3.6	3.7	3.7	3.6	3.5	3.4	3.3	3.2	3.1	3.1	3.0
% Ch	2.6	2.3	1.2	(0.7)	(1.8)	(2.2)	(2.5)	(2.8)	(2.9)	(2.8)	(2.7)	(2.4)
Health Care and Social Assistance												
Oregon	230.4	236.4	242.6	248.9	251.7	254.4	257.2	260.0	263.4	267.5	271.5	274.8
% Ch	3.5	2.6	2.6	2.6	1.1	1.1	1.1	1.1	1.3	1.5	1.5	1.2
U.S.	19.1	19.5	19.9	20.1	20.2	20.3	20.4	20.6	20.8	21.1	21.3	21.6
% Ch	2.7	2.2	2.0	1.3	0.3	0.6	0.8	0.9	1.0	1.1	1.2	1.4
Leisure and Hospitality												
Oregon	199.8	206.3	211.9	214.7	214.5	213.3	212.3	211.5	211.7	212.2	212.7	213.7
% Ch	4.3	3.3	2.7	1.3	(0.1)	(0.5)	(0.5)	(0.4)	0.1	0.3	0.2	0.5
U.S.	15.6	15.9	16.2	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.2	16.1
% Ch	3.0	1.9	1.6	0.6	0.0	0.2	0.1	(0.0)	0.0	(0.4)	(0.6)	(0.3)
Other Services												
Oregon	63.8	63.4	64.2	64.7	64.8	64.9	65.3	65.4	65.8	66.3	66.8	67.2
% Ch	4.7	(0.6)	1.2	0.9	0.1	0.2	0.6	0.2	0.6	0.8	0.8	0.6
U.S.	5.7	5.8	5.8	5.8	5.7	5.7	5.6	5.5	5.5	5.4	5.4	5.4
% Ch	1.1	1.3	0.8	(0.6)	(1.1)	(0.8)	(1.0)	(1.1)	(1.2)	(0.9)	(0.6)	(0.4)
Government												
Oregon	307.2	310.8	314.3	319.0	324.0	326.1	329.4	332.3	335.2	338.5	342.1	346.2
% Ch	2.0	1.2	1.1	1.5	1.6	0.6	1.0	0.9	0.9	1.0	1.1	1.2
U.S.	22.2	22.3	22.5	22.6	22.9	23.0	23.2	23.4	23.5	23.7	23.9	24.0
% Ch	0.9	0.5	0.6	0.8	1.4	0.2	0.8	0.8	0.8	0.7	0.7	0.7
Federal Government												
Oregon	28.3	28.2	28.1	28.1	29.6	28.4	28.4	28.4	28.4	28.4	28.4	28.4
% Ch	1.9	(0.3)	(0.4)	0.2	5.1	(4.1)	0.1	0.1	(0.0)	0.1	(0.0)	0.1
U.S.	2.8	2.8	2.8	2.8	2.9	2.8	2.8	2.8	2.8	2.8	2.8	2.8
% Ch	1.5	0.5	(0.0)	0.0	4.4	(4.3)	0.0	0.0	0.0	0.0	0.0	0.0
State Government, Oregon												
State Total	55.9	56.7	57.6	58.4	58.9	59.4	60.1	60.7	61.2	61.9	62.7	63.6
% Ch	(3.6)	1.3	1.6	1.5	0.7	0.9	1.2	1.0	0.9	1.0	1.3	1.5
State Education	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
% Ch	(77.0)	(1.2)	14.7	2.6	1.7	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Local Government, Oregon												
Local Total	223.0	226.0	228.6	232.5	235.6	238.3	241.0	243.2	245.6	248.3	251.0	254.2
% Ch	3.5	1.3	1.2	1.7	1.3	1.2	1.1	0.9	1.0	1.1	1.1	1.2
Local Education	131.6	132.9	132.8	133.8	134.7	135.6	136.4	137.1	137.6	138.1	138.9	139.6
% Ch	4.5	1.0	(0.1)	0.8	0.7	0.7	0.6	0.5	0.4	0.3	0.5	0.6

TABLE A.4
Mar 2018 - Other Economic Indicators

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
GDP (Bil of 2009 $),												
Chain Weight (in billions of $)	16,716.2	17,091.6	17,546.7	17,995.1	18,363.4	18,698.3	19,066.3	19,435.8	19,806.1	20,169.7	20,534.2	20,902.9
% Ch	1.5	2.2	2.7	2.6	2.0	1.8	2.0	1.9	1.9	1.8	1.8	1.8
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2009=100	111.4	113.4	115.7	118.3	121.1	123.9	126.6	129.5	132.4	135.3	138.3	141.3
% Ch	1.3	1.8	2.0	2.3	2.4	2.3	2.2	2.2	2.2	2.2	2.2	2.2
Personal Consumption Deflator,												
Chain Weight U.S., 2009=100	110.8	112.6	114.2	116.2	118.7	121.2	123.7	126.4	129.1	131.8	134.6	137.4
% Ch	1.2	1.7	1.4	1.7	2.2	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CPI, Urban Consumers,												
1982-84=100												
West Region, Urban Size A	254.3	262.0	267.6	273.5	281.9	289.8	297.3	305.2	313.5	321.9	330.6	339.5
% Ch	2.2	3.0	2.1	2.2	3.1	2.8	2.6	2.6	2.7	2.7	2.7	2.7
U.S.	240.0	245.1	249.2	254.1	261.3	268.1	274.5	281.2	288.1	295.3	302.6	310.2
% Ch	1.3	2.1	1.7	1.9	2.8	2.6	2.4	2.4	2.5	2.5	2.5	2.5
Oregon Average Wage												
Rate (Thous $)	51.9	53.0	55.2	57.4	59.7	62.1	64.7	67.3	70.1	73.1	76.2	79.5
% Ch	2.3	2.1	4.2	4.1	4.0	4.0	4.0	4.1	4.3	4.2	4.3	4.3
U.S. Average Wage												
Wage Rate (Thous $)	56.0	56.9	58.5	60.8	63.3	65.9	68.5	71.3	74.3	77.4	80.7	84.1
% Ch	1.1	1.6	2.8	3.9	4.1	4.1	3.9	4.0	4.2	4.2	4.2	4.3
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	368.1	399.6	428.3	451.6	471.2	489.3	508.3	530.2	552.3	574.3	597.5	621.2
% Ch	11.4	8.5	7.2	5.4	4.3	3.8	3.9	4.3	4.2	4.0	4.0	4.0
FHFA National Housing Price Index												
1991 Q1=100	232.8	247.9	260.7	269.2	278.2	287.5	296.3	306.5	317.7	329.3	341.5	354.4
% Ch	6.1	6.5	5.2	3.3	3.3	3.4	3.1	3.4	3.6	3.7	3.7	3.8
Housing Starts												
Oregon (Thous)	19.1	19.0	20.5	22.1	23.7	24.6	24.8	24.7	24.3	24.0	24.1	24.4
% Ch	19.8	(0.3)	8.1	7.7	7.2	3.7	1.1	(0.4)	(1.9)	(1.2)	0.6	1.0
U.S. (Millions)	1.2	1.2	1.3	1.4	1.4	1.5	1.5	1.5	1.5	1.5	1.5	1.5
% Ch	6.3	2.9	6.4	8.7	3.4	1.6	1.6	0.3	0.6	(0.5)	(0.5)	(0.6)
Other Indicators												
Unemployment Rate (%)												
Oregon	4.9	4.0	4.4	4.5	4.7	4.8	4.9	5.0	5.1	5.1	5.1	5.1
Point Change	(0.7)	(0.9)	0.4	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0
U.S.	4.9	4.4	3.9	3.7	3.8	4.1	4.3	4.4	4.5	4.6	4.7	4.7
Point Change	(0.4)	(0.5)	(0.5)	(0.2)	0.1	0.3	0.2	0.1	0.1	0.1	0.1	0.1
Industrial Production Index												
U.S, 2002 = 100	103.1	105.0	108.5	111.8	114.2	116.3	118.7	121.1	123.4	125.6	127.8	130.0
% Ch	(1.2)	1.9	3.3	3.0	2.2	1.8	2.1	2.1	1.9	1.8	1.8	1.7
Prime Rate (Percent)	3.5	4.1	4.9	5.6	6.1	6.5	6.5	6.4	6.1	6.0	5.9	5.7
% Ch	7.7	16.7	19.5	14.2	10.0	5.7	0.0	(2.1)	(3.9)	(1.8)	(2.3)	(1.9)
Population (Millions)												
Oregon	4.09	4.15	4.21	4.27	4.33	4.38	4.44	4.49	4.54	4.59	4.64	4.68
% Ch	1.5	1.6	1.5	1.4	1.3	1.3	1.2	1.2	1.1	1.1	1.0	1.0
U.S.	323.7	325.9	328.5	331.1	333.8	336.4	339.0	341.5	344.1	346.6	349.1	351.5
% Ch	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7
Timber Harvest (Mil Bd Ft)												
Oregon	3,888.3	3,978.2	4,028.1	4,077.1	4,121.7	4,170.0	4,227.4	4,174.1	4,170.1	4,217.3	4,211.2	4,207.9
% Ch	2.6	2.3	1.3	1.2	1.1	1.2	1.4	(1.3)	(0.1)	1.1	(0.1)	(0.1)

CASE: UE 335
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

REDACTED
June 6, 2018

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

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

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. I present Staff analysis in the general categories of Administrative and General Expenses (A&G), taxes, and pension costs. I also present more specific discussion in several A&G subcategories.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits

Exhibit Staff/502, Effective Tax Rates

Exhibit Staff/503, Data Request Responses

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. A&G EXPENSES OVERALL

Q. What are A&G expenses?

A. Administrative and general (A&G) expenses include human resources, accounting and finance, insurance, contract services and purchasing, corporate security, regulatory affairs, legal services, and information technology (IT), research and development (R&D), employee benefits and incentives, support services, and regulatory fees that fall within the Federal Energy Regulatory Commission's (FERC) definition of A&G.[1] I do not address all these A&G expenses in my testimony. Expense for the managers' deferred compensation plan, supplemental executive retirement plan, and corporate image advertising are addressed by other Staff. Expense for memberships, dues, cash contributions, R&D, and directors and officers (D&O) insurance are addressed by a settlement in principle reached by parties at a settlement conference held on May 18, 2018.

Q. Please summarize the Company's overall request for A&G expense.

A. The Company reports actual A&G expenditures of $176.1 million in 2017, budgeted expenditures of $189.9 million in 2018, and a forecasted 2019 test year amount of $180.8 million. The primary cause of the cost decrease in 2019 is exclusion of $15.2 million of incentive plan costs from the rate case compared to 2017.[2] The decrease in incentive plan costs from 2018 to 2019 is $17.6 million. Without this reduction the 2019 test year expense would be

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[1] PGE/500, Lobdell-Batzler/1.
[2] PGE/500, Lobdell-Batzler/5.

$198.4 million, which is an increase of 11.3 percent over 2017, and 4.5 percent over 2018. The average increase is 6.1 percent on an annualized basis.

The Company cites the cost of employee benefits and human resource (HR) services as the primary drivers of the increase in A&G costs. In opening testimony the Company cites an offsetting savings of $2.5 million from renewal of the World Trade Center (WTC) lease.[3] The Company subsequently stated that the actual WTC savings to PGE, net of operating cost increases and allocations to other tenants, is $0.8 million.[4] This would be a revision to testimony only, no change in the 2019 revenue requirement.

Q. What is the increase in non-labor A&G costs, excluding the items that are addressed by other Staff or the settlement-in-principle?

A. The amount of non-labor A&G costs is $94.6 million in 2017, budgeted expenditures of $103.5 million in 2018, and $109.1 million in 2019.

Q. Please describe the scope of review for A&G expenses.

A. The starting point for Staff review is the Company's report of "A&G Costs by Major Functional Area" in PGE's testimony.[5] We also reviewed work papers provided by the Company, in particular Corporate Support 2019.xlsx and the Company's responses to standard data requests (SDR).

Q. Are you the only Staff assigned to review A&G expenses?

[3] PGE/500, Lobdell-Batzler/4.
[4] PGE Response to Staff DR No. 206.
[5] PGE/500, Lobdell-Batzler/2, Table 1.

A. No, it is a team effort. A&G expense includes both labor and non-labor costs that encompass numerous issues that are customarily reviewed in a general rate case. Accordingly, several Staff are involved in reviewing the various subcategories of A&G. My role is to perform a general review of non-labor portion of A&G and the specific areas presented in the remainder of my testimony.

Q. How did Staff review these costs?

A. Staff reviewed the increases in line item costs (cost element) for A&G, in A&G as whole and also for each major functional area and individual work units (RC) therein followed by a series of data requests.[6]

Q. Is Staff proposing across the board adjustments for non-labor A&G costs?

A. Yes, Staff is proposing an escalation reduction for non-labor A&G costs of ($2.697) million. This adjustment is based on the All Urban CPI index[7] from 245.1 in 2017 to 254.1 in 2019. This results in a percentage increase of 3.67 percent from 2017-2019. This adjustment is after all other Staff adjustments have been applied to specific accounts.

[6] Staff/503, PGE Responses to Staff DR Nos. 195-216.
[7] Appendix A, March 2018 OEA Forecast CPI, Urban Consumers, U.S. % Ch.

ISSUE 2. HR/EMPLOYEE SUPPORT

Q. Please summarize the Company's overall request.

A. PGE's testimony describes an overall increase of 20 percent for talent acquisition and training costs, from $4.5 million in 2017 to $5.4 million in 2019.[8] This testimony also states that the increase includes $0.7 million from 2017-2018 and that this is consistent with the forecasted increase presented in PGE's previous rate case (Docket No. UE 319).[9] This section of PGE's testimony is devoid of further financial details regarding this increase except the assertion that $0.4 million of training costs have been excluded in 2018 and 2019 as a result of Docket No. UE 319.

PGE also discusses talent acquisition and training in testimony regarding compensation.[10] However, its testimony regarding compensation does not quantify what PGE reports are increased training and HR activities.

Q. What is the overall increase in HR costs?

A. Overall HR costs increased are projected to increase by $2.3 million.[11] The following table summarizes the increase:

[8] PGE/500, Lobdell-Batzler/6-9.
[9] PGE/500, Lobdell-Batzler/6.
[10] PGE/400, Mersereau/Neitzke/5-8.
[11] PGE/500, Lobdell-Batzler/2, Table 1.

HR Cost Increase 2017-2019:	(mil.)
Increase in talent acquisition and training labor costs	$ 0.312
Increase in benefits recorded as non labor cost	0.314
Other non labor talent acquisition and training costs	0.315
Cost increase cited in testimony	0.941
Cost increases in other HR Departments	1.355
	$ 2.296

Q. What is Staff's response to PGE's testimony regarding the need for resources for talent acquisition and training?

A. Staff notes that the majority of the actual cost increases, which are for ten additional FTE and various non-labor costs, are not related to talent acquisition and training .[12] Furthermore, a number of the FTE movements discussed in the Company's responses to DR Nos. 284 through 286 appear to have occurred subsequent to preparation of the Company's work papers.[13]

Q. Is Staff proposing an adjustment?

A. Yes, Staff is proposing to remove the cost of the vacant analytical support positon in HR Admin and the cost to backfill the administrative assistant position transferred out of the Payroll department. This adjustment is included in the overall FTE adjustment prepared by Marianne Gardner.

[12] Staff/503, PGE Responses to Staff DR Nos. 284-286.
[13] FTE changes as presented in the work paper "Corporate Support.xlsx".

ISSUE 3. LIABILITY INSURANCE

Q. Please summarize the Company's overall request.

A. PGE states its costs for property and liability insurance have increased, citing a 3.4 percent annualized rate of increase in property and liability costs not including offsetting membership credits given to PGE by insurers and the cost of non-primary layers of D&O insurance.[14] PGE also cites a 12.1 percent annualized increase in retained losses. PGE asserts that recent losses due to "natural catastrophe exposure" could lead to premium increases of 10 percent or greater.

Q. Does Staff have proposed adjustments to the Company's forecasted expense for insurance?

A. Staff proposes an adjustment to the Company's forecasted expense for "Main At-Risk Property" insurance. Based on review of the Company's work papers, Staff has no adjustment to the Company's forecasted expense for the following insurance lines:

- Renewables All Risk Property
- Fidelity and Crime
- Fiduciary Liability
- Workers Compensation
- Nuclear Liability
- Cyber Liability

[14] PGE/500, Lobdell-Batzler/19-23.

- Aircraft and Hull Liability
- Surety Bonds
- General & Auto Liability

Q. What are Staff's conclusions regarding PGE's costs for Main All-Risk Property insurance?

A. **[Begin Confidential]**[redacted]

15 [redacted]

[redacted]**[End Confidential]** Staff's proposed adjustment to the percent increase reduces test year expense by an adjustment of ($0.151) million.

Q. What are Staff's conclusions regarding allowances for retained losses?

A. Staff finds the proposed 2019 retained loss amount $1.816 million for Worker's Compensation is reasonable. This is comparable to the recent average for 2015-2017 of $1.862 million.[16]

Retained losses for Auto and General Liability are projected at $1.594 million for both 2018 and 2019. Staff is proposing retained losses for Auto and General Liability be reduced to $1.152 million based on the average of 2014, 2016, and 2017 not including escalation. The proposed reduction in test year expense results in an adjustment of ($0.442) million.

Q. What are Staff's conclusions regarding continuity and membership credits?

A. Continuity and membership credits averaged $828,396 from 2014-2017. The Company asserts that "[i]t is not possible to predict with any certainty when an

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16 [redacted]

insurer may elect to issue a credit and if so, to what extent"[17] and therefore does not include forecasted credits in the test year. Staff understands that the annual credits are not assured but the amount has been relatively consistent for the past four years: $0.712, $0.797, $0.829, and $0.975 million for the years 2014 through 2017, respectively. Accordingly, Staff recommends a reduction to the 2019 test year expense of ($0.8) million.

[17] PGE Response to Staff DR No. 071, OPUC DR 071_Attach A_CONF.xls

ISSUE 4. EMPLOYEE BENEFITS

Q. Please summarize the Company's overall request.

A. The Company testifies that total benefit costs are increasing from $82.3 million in 2017 to $96.5 million in 2018, and are expected to be $100.5 million in 2019.[18] Staff calculates the requested 2017 to 2019 percentage increase as follows:

- Health and Wellness +31.2 percent
- Disability and Life Insurance +49.4 percent
- Post-Retirement +7.6 percent
- Miscellaneous Benefits +117.0 percent
- Benefits Administration +72.7 percent

The Company asserts that PGE's higher than average benefit program[19] is offset by a decision to use wage and salary escalation of 3.5 percent rather than the OEA forecasted escalation of 4.5 percent. The Company also cites a PricewaterhouseCoopers projecting medical cost increases of 6.5 percent nationally.[20]

The Company reports that all nonunion employees will be shifted to Health Savings Account-qualified (HSA) accounts beginning in 2018. HSA accounts will be optional for union employees. In conjunction with this transition the Company is shifting premium dollars to fund the beginning balances in employee HSA accounts.[21]

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[18] PGE/400, Mersereau-Neitzke/28, Table 1.
[19] Benchmark is Willis Towers Watson Energy Services BENVAL study. Peer group for study includes 14 regulated utilities with annual revenues between $1 and $3 billion.
[20] PGE/400, Mersereau-Neitzke/28-29.
[21] PGE/400, Mersereau-Neitzke/30.

Projected 2019 disability and life insurance costs include: $0.7 million union short term disability, $2.3 million long term disability, $1.3 million group life.[22] Post retirement includes 401(k) and defined benefit pension costs, which are discussed in a separate issue below. The remainder of post-retirement cost is the HRA benefit for retiree, which is projected at $2.3 million in 2019.[23] Projected 2019 miscellaneous benefits include: educational assistance $0.5 million, service awards $0.2 million, and transit passes $0.6 million. Benefit admin costs are $1.0 million, which the company asserts is consistent with Docket No. UE 319.[24]

Q. What are Staff's conclusions regarding the Company's health and dental benefit plans?

A. 2019 will be the first year that the Company offers only Health Savings Account (HSA) qualified health plans.[25] The 2018 to 2019 cost premium increases for these plans are 7 percent with the exception of one family plan that increased 5.6 percent. Staff compared the 2019 premiums with the average cost of coverage reported by the Kaiser Family Foundation.[26] The Company premiums, on average, are higher than the reported average for single plans and very close to the reported average for family coverage. Based on this

[22] PGE/400, Mersereau-Neitzke/32.
[23] PGE/400, Mersereau-Neitzke/33.
[24] PGE/400, Mersereau-Neitzke/37-38.
[25] PGE Response to Staff DR No. 064, OPUC DR 064_Attach A_CONF
[26] *Employer Health Benefits 2017 Annual Survey*, The Kaiser Family Foundation and Health Research & Education Trust.

survey and the PricewaterhouseCoopers information provided by the Company, Staff believes the premiums for 2019 are reasonable.

The Company also provided information reconciling the $12.6 million increase in benefit plan costs from 2017 to 2019.[27] This information indicates that the employee census has been held flat for the bargaining unit and non-bargaining unit plans in 2018. Accordingly, the primary cost driver for 2019 is the premium costs noted above.

Based on the above analysis and careful review of PGE's responses to the standard data requests and supplemental data requests, Staff finds the forecasted expense for employee health and dental plans to be reasonable.

Q. What are Staff's conclusions regarding long-term disability costs?

A. PGE reports its cost of long-term disability insurance is projected to increase 90 percent from $1.196 million in 2017 to $2.276 million in 2019. The Company explains this is due to an increase in covered FTE, a one-time credit of $0.8 million in 2017, and increases in the medical and dental portion of the disability program.[28] Staff finds the proposed increases for 2019 to be reasonable.

Q. What are Staff's conclusions regarding group life insurance?

A. PGE reports its cost of group life insurance is projected to increase 27 percent from $1.0 million in 2017 to $1.266 million in 2019. The Company explains this is due to a decrease in the actuarial Expected Long-term Return on Plan

[27] UE 335_AWEC DR 020_Attach A_CONF
[28] PGE Response to Staff DR 235 CONF.pdf

Assets (EROA) while the discount rate remains unchanged. Staff finds the proposed increases for 2019 to be reasonable.

Q. What are Staff's conclusions regarding the Company education plan?

A. PGE reports its cost of educational assistance is projected to increase 107 percent from $0.222 million in 2017 to $0.460 million in 2019. The Company explains that this increase is primarily a business decision related to recruitment and retention. The Company currently provides a maximum benefit of $2,000 and $4,000 per year for undergraduate and graduate level courses, respectively. **[Begin Confidential]**[redacted]**[End Confidential]** Staff finds the proposed increases for 2019 to be reasonable.

Q. What are Staff's conclusions regarding miscellaneous employee benefits?

A. PGE reports its cost of miscellaneous employee benefits is projected to increase 278 percent from $0.250 million in 2017 to $0.946 million in 2019. The Company explains that the increase is due to establishment of a mass transit benefit as discussed in opening testimony[29] and providing electric vehicle charging at PGE worksites. Staff finds the proposed increases for 2019 to be reasonable.

Q. What is Staff's conclusion regarding benefit administration costs?

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[29] PGE/400, Mersereau-Neitzke/38.

A. PGE reports its benefit administration costs are projected to increase 73 percent from $0.597 million in 2017 to $1.031 million in 2019. The Company explains the increase is mostly due to continued investment in HR related technology improvements. The Company's response to Staff's data request for additional information regarding the nature of this increase was vague and did not identify the specific vendors or services being purchased.[30] Staff is recommending a reduction in test year expenses of ($0.4) million.

Q. Does Staff have proposed adjustments to the remaining employee benefit expense?

A. No. Based on review of the Company's work papers, Staff has no adjustment to the Company's forecasted test year expense for its:

- Employee Wellness Program
- Employee Assistance Program
- Short Term Disability Program
- Health Reimbursement Account
- Involuntary Severance Program (zero in 2019)

[30] PGE Response to Staff DR No. 235, OPUC DR 235 CONF.pdf and OPUC DR 235_Attach C_CONF.xlsx

ISSUE 5. INCOME TAXES

Q. Q. Please summarize the Company's overall request.

A. The Company is projecting current state income taxes to decrease from $26.2 million to $21.4 million for 2018 and 2019, respectively.[31] The Company is projecting current federal income taxes to decrease from $108.6 million to $53.2 million for 2018 and 2019, respectively. The Company is projecting the current provision for deferred taxes will decrease from $18.3 million to $17.2 million for 2018 and 2019, respectively. The Company is also projecting a rate payer benefit from amortization of excess deferred income taxes of $7.0 million in 2019. This is a new element in this rate case resulting from federal tax reform.[32]

Regarding rate base, the Company proposes a reduction of $679.7 million for accumulated deferred taxes compared to $634.4 million (as filed) in the previous rate case.[33]

Q. Please summarize the applicable requirements for ratemaking treatment of federal income tax (FIT), state income tax (SIT) and accumulated deferred income tax (ADIT).

A. Consistent with Internal Revenue Code (IRC) Sections 168(f)(2) and 168(i)(9) (Normalization Rules for Public Utilities) and ORS 757.269(1), public utilities are required to normalize federal income taxes for revenue requirement

[31] PGE/205, Tooman-Espinoza/1.
[32] H.R.1 — Tax Cuts and Jobs Act (H.R.1 or Act).1 The Act was signed into law on December 22, 2017 by President Donald Trump, with most provisions going into effect on January 1, 2018.
[33] *See In The Matter of Portland General Electric Company, Request for a General Rate Revision*, Docket No. UE 319, Order No. 17-511 (Dec 18, 2017).

purposes. Normalization of federal income taxes means that a regulated public utility that uses accelerated depreciation for tax purposes must record in rate base a related deferral of taxes that arises from the difference between book depreciation and tax depreciation. According to IRC Sec. 168(i)(9)(A):

> In order to use normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2)—
> (i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and
> (ii) if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Also, ORS 757.269 (1) states "[s]ubject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operation of the utility." According to subsection (3):

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

> group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation; (b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or (c) Any other considerations the commission deems relevant to protect the public interest.

Q. Does the Company's request include ratepayer benefits for the effects of tax reform in 2018?

A. No, those benefits are expected to be deferred and refunded at a future date under a separate Commission docket. The Company currently estimates 2018 ratepayer benefits of between $25 million and $30 million dollars.[34]

Q. Could the 2018 benefits be passed through to ratepayers as an adjustment in this case?

A. Yes, however the Company asserts that ORS 757.259(5) specifies that an earnings review be applied to the 2018 benefits. Accordingly, the Company proposes to defer the 2018 benefits under UM 1920 until the 2018 results of operations are known in early 2019.

Q. What are Staff's conclusion regarding the Company's provision for current state income taxes?

A. The Company reports an increase in the composite state and local tax rate from 7.582 percent to 7.786 percent with respect to the previous rate case.[35] The increase is mostly due to a shift in apportionment weighting from Montana

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[34] *See In the Matter of Portland General Electric Company, Supplement to Application for the Deferral Of 2018 Net Benefits Associated with the U.S. Tax Reconciliation Act,* Docket No. UM 1920, (April 13, 2018).
[35] PGE/202, Tooman-Espinoza/1 and UE 319 Tooman-Brown 201/3.

and California to Oregon and the addition of the City of Portland to the composite rate. Staff finds these changes to reflect a reasonable fluctuation in year to year apportionment factors.

Staff finds the change in state income taxes is otherwise proportionate to the change in taxable income at the 7.786 percent rate. Staff is not proposing any adjustments to the state tax calculation at this time.

Q. What are Staff's conclusions regarding the Company's provision for current federal income taxes?

A. The reduction in the federal statutory rate due to tax reform is 14 percent (35 percent to 21 percent).The Company reports overall effective tax rates on book income of 41.71 percent in 2018 and 26.88 percent in 2019 corresponding to a rate reduction of 14.83 percent. Exhibit 501 shows the effective tax rate without state taxes and amortization of excess deferred income taxes changed from 33.92 percent to 21.31percent, a reduction of only 12.61 percent. Staff notes that this decline includes changes in both the current and deferred portion of federal taxes for the test year. Accordingly, Staff is concerned that the full benefits of the change in the federal statutory rate are not flowing through to ratepayers.

Q. What are Staff's conclusions regarding the amortization of excess deferred income taxes (EDIT)?

A. The Company reports amortization of $7.0 million in EDIT in the 2019 test year. This amount flows through to ratepayers as a benefit in addition to the reduction in the federal statutory rate. The Company reports approximately

$320 million of excess ADIT related to depreciable plant.[36] As a reasonableness test, Staff notes that dividing this amount by the composite remaining life of depreciable plant (22.2 years[37]) would yield a straight-line annual amortization amount of approximately $14.4 million. Accordingly, since this amount is much larger than the amortization reported in the rate case, Staff is concerned that the full benefits of accumulated excess deferred income taxes are not flowing through to ratepayers.

Q. Did the Company provide any additional information regarding how the EDIT reversal was determined?

A. Yes, one of the data responses in this case[38] shows additional detail labeled as “Tax Provision Total Tax Analysis Report”, which did not include any details about how the reversals are calculated with respect to the $320 million regulatory liability noted above.

Q. How are the excess deferred taxes being handled in rate base?

A. The test year rate base reduction of $679.7 million appears to be inclusive of the unamortized excess deferred income taxes.

Q. Is Staff proposing an income tax expense or rate base adjustment for accumulated deferred income taxes at this time?

[36] *See In the Matter of Portland General Electric Company, Supplement to Application for the Deferral Of 2018 Net Benefits Associated with the U.S. Tax Reconciliation Act,* Docket No. UM 1920, (April 13, 2018).
[37] *See In the Matter of Portland General Electric Company, 2015 Detailed Depreciation Study of Electric Utility Properties,* Docket No. UM 1809, Order No. 17-365, (Sep 26, 2017).
[38] PGE Response to AWEC DR No. 45, UE 335_AWEC DR 045_Attach A_CONF.

A. No, Staff needs additional time to study the how taxes are being applied in this case. However, due to the magnitude of the changes associated with tax reform, Staff requests that Company experts provide a technical workshop to discuss how the benefits of tax reform are being calculated and flowing through to ratepayers.

ISSUE 6. TAXES OTHER THAN INCOME

Q. Please summarize the Company's overall request.

A. The Company is projecting an increase from $122.4 million in 2017 to $126.8 and $138.5 million in 2018 and 2019, respectively.[39]

Q. Does your testimony include all taxes other than income?

A. No, my testimony on this issue will discuss increases in property taxes, miscellaneous taxes, and license fees. Payroll taxes and franchise fees are discussed in the testimony of Staff Witness Marianne Gardner.

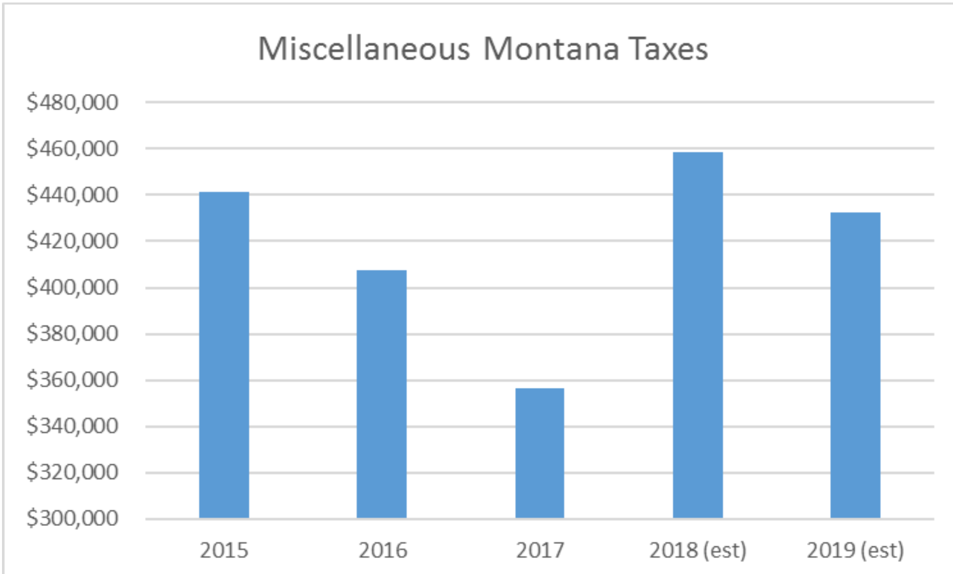
The following table presents the percentage increases for property taxes, miscellaneous taxes, and license fees:

	2017-2018	2017-2019
Property Taxes - Oregon	4.2%	17.1%
Property Taxes - Washington	11.9%	20.3%
Property Taxes - Montana	24.1%	9.9%
Misc. Tax & Lic Fees - Oregon	-8.6%	-8.6%
Misc. Tax & Lic Fees - Montana	28.6%	21.4%

Q. What are Staff's conclusions regarding miscellaneous taxes and licenses?

A. As PGE reports, miscellaneous taxes and licenses were $2.6 million in 2017 and are projected to be $2.5 million per year in 2018 and 2019. The increase in miscellaneous Montana tax is due to fluctuations in energy production at Colstrip. 2017 was an unusually low year as illustrated in the following chart:

[39] PGE/200, Tooman-Espinoza/15



Q. What are Staff's conclusions regarding Washington property taxes?

A. According to PGE, Washington property taxes are increasing from $2.1 million in 2017 to $2.4 million in 2018 and $2.5 million in 2019.[40] The Company explains that the expected increases are attributed to a higher estimated tax assessment for Tucannon based on historically trended assessed values.[41] Staff is not proposing an adjustment for Washington property taxes.

Q. **What are Staff's conclusions regarding Montana property taxes?**

A. According to PGE, Montana property taxes are increasing from $4.8 million in 2017 to $6.0 million in 2018 and then decreased $5.3 million in 2019.[42] The Company explains that the increase from 2017 to 2018 is attributed to higher estimated tax rates for Colstrip followed by a change in the Montana

[40] Exhibit Support 2019_Tax Plan, Account 4081002.
[41] PGE Response to Staff DR No. 278, PGE Response to Staff DR 278.pdf
[42] Exhibit Support 2019_Tax Plan, Account 4081003.

apportionment calculation in 2019. Staff is not proposing an adjustment for Montana property taxes.

Q. **What are Staff's conclusions regarding Oregon property taxes?**

A. According to PGE, Oregon property taxes are increasing from $53.7 million in 2017 to $56.0 million in 2018 and $63.0 million in 2019.[43] Staff notes that these amounts appear to be reduced by approximately $3 million per year of net Strategic Investment Program (SIP) tax benefits when compared to PGE's response to Staff DR 278.

[Begin Confidential][redacted]**[End**

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[43] Exhibit Support 2019_Tax Plan, Account 4081001
[44] [redacted]
[45] PGE Response to Staff DR No. 278, OPUC DR 278.pdf
[46] PGE's Response to Adjustment S-11 - Work Paper

Confidential]Accordingly, Staff is not proposing an adjustment for Oregon property taxes. However, Staff would like to note the magnitude of the increase for reference in future rate cases.

ISSUE 7. PENSION AND POST RETIREMENT BENEFIT PLAN EXPENSES

Q. Please summarize the Company's overall request.

A. Defined benefit costs (FAS 87) included in the rate case are $21.5 million in 2017, increasing to $26.2 million in 2018, and decreasing back to $21.5 million in 2019. These costs reflect an assumed seven percent long-term rate of return on assets and use a discount rate of 3.64 percent for the pension benefit obligation. The Company will monitor the discount rate and propose a final rate no later than September 2018.[47]

PGE will continue to capitalize pension and post retirement plans in a manner consistent with PGE's method prior to the issuance of Accounting Standards Update (ASU) No. 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost." For 2019, the Company expects to capitalize $7 million of the total FAS 87 cost.[48] 401(k) costs are expected to increase from $20.7 million to $23.3 million for 2017 and 2019, respectively.[49]

Q. What are Staff's thoughts regarding the Company's proposal to update the discount rate?

A. Given that the discount rates are based on a group of long-term high quality AA-rated bonds and we are currently in an environment of increasing rates,

[47] PGE/400, Mersereau-Neitzke/36, PGE response to Staff DR No. 222, OPUC DR No. 059 Supp 1_Attach B_CONF
[48] PGE/400, Mersereau-Neitzke/34.
[49] PGE/400, Mersereau-Neitzke/33.

Staff would expect that subsequent revision of the discount rate would be in an upward direction thereby reducing the benefit liability relative to plan assets.

Q. What are Staff's conclusions regarding the discount rate?

A. Based on the Company's responses to Staff DR No. 220, Staff believes the discount rates being used are reasonable for both the pension plan and the various postretirement benefit plans.

Q. What are Staff's conclusions regarding the long-term rate of return on plan assets?

A. Based on the Company's responses to Staff DR No. 220, Staff believes the seven percent assumed rate of return is somewhat conservative. However, the Company's observation that the decrease to seven percent has already been vetted in the previous rate case is valid. Accordingly, Staff is not proposing an adjustment in 2019.

Q. What would be the effect on 2019 pension costs if the return on assets was 7.25 percent?

A. A 25 basis point increase would decrease costs by $1.5 million.[50]

Q. Is the funded status of the Company's plans improving?

A. The Company reports the funding status of the defined benefit pension plan as 72.6 percent, 70.1 percent, and 72.4 percent for years 2015 through 2017, respectively. The Company reports the funding status of the other postretirement benefit plans as 37 percent, 41.1 percent, and 42.3 percent for years 2015 through 2017, respectively. Accordingly, the funded status of the

[50] Staff/503, PGE Response to OPUC Standard Data Request No. 060.

pension is holding steady and the post retirement plans have improved. This is evidence that the plans are generally stable and the costs being borne by ratepayers are reasonable.

Q. Has Staff identified any issues regarding pension plan valuation?

A. **[Begin Confidential]** [redacted] **[End Confidential]**

While acknowledging Staff has no specialized actuarial expertise, Staff questions this information from a common sense perspective for several reasons:

- Conceptually it makes no sense why the plan would assume promotional increases for non-union employees but not union employees, a portion of which are also, presumably, staying with the Company and moving to positions of increasing responsibility and pay as their careers progress.

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51 [redacted]

52 [redacted]

- The method does not appear to compensate for any level of employee attrition.
- The large annual increases assumed for younger non-union employees will compound to vary large numbers over a 45 year career.
- The actual employee census in any particular year will include the full range of employees at various career stages and compensation levels. Also assuming like increases for each employee appears to be "double counting" the increase from a current year service perspective.

In sum, Staff believes the assumed rates of increase could be leading to an overstatement of the pension benefit obligation and also the FAS 87 expense being borne by ratepayers.

Q. Did Staff request the Company to provide a range of cost scenarios with different assumptions?

A. No, Staff recognizes that running additional actuarial calculations would be costly for the Company. However, Staff would like to have continuing dialogue with the Company and parties both to allow parties to comment and also to allow the Company to provide additional information prior to asking the Company to recalculate the pension benefit obligation.

Q. Does Staff have any concerns about the Company's implementation of Accounting Standards Update (ASU) No. 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost"?

A. Yes, the footnotes to the Company's 2017 financial statement indicate the Company has set up a regulatory asset for the FAS 87 expense in excess of service cost. This amount is estimated at $3 million annually.

Q. Did the Company provide additional information?

A. Yes the Company's response to Staff DR No. 224 indicates the $3 million non-service cost has been capitalized as plant for regulatory purposes. For Security and Exchange Commission (SEC) purposes it is set up as a regulatory asset that will be amortized. The Company states that it has developed a "dual recordkeeping system" to keep track of the SEC and regulatory basis differences.

Q. Is Staff proposing a rate case adjustment?

A. No, the Docket No. UE 319 settlement (Order No. 14-511) and FERC Docket No. AI18-1-000 "Accounting and Financial Reporting for Pensions and Post-retirement Benefits other than Pensions" do not specifically discuss a regulatory asset though the existence of one is implied. Staff is including this in testimony to memorialize that a basis difference now exists.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 335
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

June 6, 2018

WITNESS QUALIFICATIONS STATEMENT

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

CASE: UE 335
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

June 6, 2018

Effective Tax Rates

		(a)	(b)	(c)	(d)	(e)	(f)
Line		UE 319 2018 Order 17-511	UE 335 2019 Test Year	Rate Change			
	Per PGE/205, Tooman-Espinoza/1						
1	Book Taxable Income	$ 367,138	$ 315,514				
2	Federal Taxable Income	$ 310,369	$ 253,361				
3	Current Federal Taxes	$ 108,629	$ 53,206				
4	Tax Rate	35.00%	21.00%	-14.00%			
5	State Tax	26,202	21,394				
6	Federal Tax	108,629	53,206				
7	Amortization of Excess Deferred Taxes (EDIT)	-	(7,010)				
8	Def Tax	18,301	17,208				
9	Total Tax Expense	$ 153,132	$ 84,798				
10	Effective rate as percent of book income	41.71%	26.88%	-14.83%			
	Additional Staff Calculations:						
11	Without ARAM	$ 153,132	$ 91,808				
12	Effective rate w/o EDIT amortization	41.71%	29.10%	-12.61%			
13	State Tax Rate	7.785%	7.787%				
14	Federal effective rate w/o EDIT amortization	33.92%	21.31%	-12.61%			

CASE: UE 335
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Exhibits in Support
Of Opening Testimony

REDACTED
June 6, 2018

April 20, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 214
Dated April 6, 2018

Request:

Regarding removal of "50% of certain layers of directors' and officers' insurance" (Pope-Lobdell 100/16),

a. **Please provide an analysis of the expenses in account 9302004 MiscGenExp-Dir Fees & Exps identifying the costs subject to the 50% reduction and reconciling to the $432,074 reduction shown in the work paper "Corporate Support 2019".**

Response:

a. PGE is requesting 100% of the first layer (i.e., Aegis) of directors' and officers' (D&O) coverage and 50% of the non-primary layers (i.e., EIM, US – HCC, and XL – Side A Excess DIC). Please see PGE confidential work paper, "2019 Insurance Forecast Detail_CONF", cells F8, F9, and F13 for the premiums for the non-primary layers. One half of these amounts represents PGE's adjusting entry.

April 23, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 219
Dated April 6, 2018

Request:

Please provide a copy of the power point slide deck shown at the pre-rate case meeting regarding pensions on Feburary 8th, 2018 in Salem.

Response:

Attachment 219-A provides the requested information.

Attachment 219-A is protected information and subject to Protective Order No. 18-047.

UE 335

Attachment 219-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

2/8/2018 Pension Update to Staff

April 23, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 220
Dated April 6, 2018

Request:

Regarding the "distribution of long-term expected return information provided by Mercer Investment Management Company" referenced in testimony (Mersereau – Neitzke 400/35),

a. **Please provide copies of any reports or other documents received from Mercer related to this information.**
b. **Please provide an explanation of the company's decision to reduce the Expected Long-Term Return on Plan Assets from 7.5% to 7.0% including:**
    i. **The rationale and business objectives underlying the decision to reduce the Expected Long-Term Return on Plan Assets.**
    ii. **Benchmarks or other information considered other than the Mercer information.**
    iii. **Related changes in the target asset allocation from 67% equity, 33% debt reported for 2017.**
    iv. **List of Company employees and related parties involved in determining the Expected Long-Term Return on Plan Assets.**
    v. **List of meetings and dates where the decision to reduce the Expected Long-Term Return on Plan Assets was discussed and whether minutes for those meetings are available.**
    vi. **Dates of all communications between the Company and Mercer regarding decision to reduce the Expected Long-Term Return on Plan Assets and whether those communications exist in written form.**

Response:

PGE objects to this request on the basis that it is vague, overly broad, and unduly burdensome. Notwithstanding its objection, PGE replies as follows.

a. Attachment 220-A provides the December 2017 Mercer Range of Long-Term Portfolio Return, which PGE relied upon in determining to keep the Expected Return on Assets (EROA) used for determining the 2019 pension expense forecast at 7.0%, consistent with the level used for 2018 and discussed in Docket No. UE 319.

b. PGE made the decision to reduce its EROA from 7.5% to 7.0% for the 2018 test-year and 2018 budget, as discussed in UE 319. As discussed in that case, the 7.0% assumption more closely aligns with the data provided by Mercer at the 50th percentile. See Attachment 220-A. PGE also reviewed EEI survey data from 2014 – 2016. There is a downward trend in the survey data (i.e., peer utilities are reducing their EROA assumptions). Attachment 220-B displays the trend analysis completed by PGE in early 2017. Because historical observations in the EEI data show a trend towards the forward-looking views provided by Mercer, it is reasonable to use an EROA that more closely aligns with the data provided by Mercer.

   i. See part (b) above.
   ii. See part (b) above
   iii. PGE has not changed its target asset allocation for a number of years and currently does not plan to make a change. PGE's target asset allocation is primarily based on the funded status of the plan, which we do not foresee significant changes to in the near term.
   iv. The EROA is initially developed between PGE's Treasury department and Mercer. Then, this rate is presented to PGE's Accounting, Human Resources, and Treasury management, with the final approval residing with PGE's Vice President of Human Resources, Diversity & Inclusion and PGE's Senior Vice President of Finance, Chief Financial Officer, and Treasurer.
   v. PGE does not have a list of nor are we aware of any meetings that took place regarding this change. However, Attachment 220-C provides a memo including the recommendation to lower PGE's EROA to 7.0% for 2018.
   vi. PGE does not have the dates of verbal communications that may have occurred with Mercer regarding this change. However, we were able to locate an October 2016 email discussing the potential change. Attachment 220-D provides this email.

Attachments 220-A through 220-D are protected information and subject to Protective Order No. 18-047.

UE 335

Attachment 220-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

December 2017 Mercer Range of Long-Term Portfolio Return

UE 335

Attachment 220-B

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

EROA Trend Analysis

UE 335

Attachment 220-C

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

EROA Request for Approval

UE 335

Attachment 220-D

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

October 2016 Communication with Mercer

April 23, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 221
Dated April 6, 2018

Request:

Regarding the "discount rate is provided by Willis Towers Watson, and the methodology is determined in accordance with Generally Accepted Accounting Principles" referenced in testimony (Mersereau – Neitzke 400/35),

a. **Please provide copies of any reports or other documents received from Willis Towers Watson related to the discount rate.**
b. **Please provide an explanation of the company's decision to reduce the discount rate from 4.17% to 3.65% including:**
   i. **The rationale and business objectives underlying the decision to reduce the discount rate.**
   ii. **Benchmarks or other information considered other than the Willis Towers Watson information.**
   iii. **List of Company employees and related parties involved in determining the discount rate.**
   iv. **List of meetings and dates where the decision to reduce the discount rate was discussed and whether minutes for those meetings are available.**
   v. **Dates of all communications between the Company and Willis Towers Watson regarding decision to reduce the discount rate and whether those communications exist in written form.**

Response:

PGE objects to this request on the basis that it is vague, overly broad, and unduly burdensome. Subject to and without waiving its objection, PGE replies as follows.

a. Attachment 221-A provides PGE's Actuarial Valuation report for Fiscal Year 2018. This report provides an estimate of PGE's 2018 FAS 87 pension expense, including the discount rate assumption. Attachment 221-B provides the Willis Towers Watson Year-End 2017 BOND:Link Discount Rate Modeling Analysis provided to PGE at the beginning of 2018. Attachment 221-C provides PGE's 2017 year-end pension and post-retirement financial statement. PGE based its 2019 discount rates on assumptions used for 2018.

b. PGE's determination of its discount rate is informed by data from a third-party consultant, Willis Towers Watson. Willis Towers Watson completes its discount rate modeling analyses using BOND:Link.

   i. PGE's pension discount rate is applied consistently based upon our pre-determined accounting policy, which uses Willis Towers Watson's BOND:Link methodology. As discussed in PGE Exhibit 400, PGE's annual discount rates are based on a portfolio of high-quality bonds that match the duration of the plan cash flows. As changes in the portfolio of high-quality bonds change due to market changes, PGE updates accordingly.
   ii. Attachment 221-D provides a 2017-2018 Edison Electric Institute Pension and Other Post-Employment Benefits (OPEB) Survey, which includes expected discount rates. In this survey, the median discount rate assumption for 2017 is 3.70%.
   iii. The discount rate is initially developed between PGE's Accounting department and Willis Towers Watson. Then, this rate is presented to PGE's Accounting, Human Resources, and Treasury management, with the final approval residing with PGE's Vice President of Human Resources, Diversity & Inclusion and PGE's Senior Vice President of Finance, Chief Financial Officer, and Treasurer.
   iv. PGE is aware of two separate meetings that may have included discount rate discussions related to setting PGE's 2018 discount rate assumption. These meetings occurred on May 25, 2017 and October 25, 2017. Meeting minutes do not exist. However, Attachments 221-E and 221-F provide the materials reviewed.
   v. See PGE's response to part (iv), above. Additionally, Attachments 221-G and 221-H provide email communications confirming the 2018 discount rate assumption, which PGE also used for the 2019 pension expense and OPEB forecast.

Attachments 221-A through H are protected and subject to Protective Order No. 18-047

UE 335

Attachment 221-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Willis Towers Watson FY 2018 Actuarial Valuation Report

UE 335

Attachment 221-B

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Towers Watson Year-End 2017 BOND:Link Discount Rate Modeling Analysis

UE 335

Attachment 221-C

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

PGE 2017 Year-End Pension and Post-Retirement Financial Statement

UE 335

Attachment 221-D

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

2017-2018 Edison Electric Institute Pension and Other Post-Employment Benefits Survey

UE 335

Attachment 221-E

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

2017 Preliminary Pension Valuation Results Meeting – May 25, 2017

UE 335

Attachment 221-F

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Discussion of Assumptions and Planning for Year-End
2017 Financial Disclosures and 2018 Valuations – October 25, 2017

UE 335

Attachment 221-G

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

1/10/2018 Email to Willis Towers Watson

UE 335

Attachment 221-H

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

12/15/2017 Email to Willis Towers Watson

April 23, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 222
Dated April 6, 2018

Request:

Regarding the excel workbook OPUC_SDR_059_Attach A_CONF, FAS 87 tab,

a. **Please resubmit with a column and plan information added for 2018.**
b. **For the 2019 column, please provide a detailed explanation for how the values on each line were determined and all supporting calculations (staff was unable to find this information in the actuarial reports provided by the company).**

Response:

a. See PGE's first supplemental response to OPUC Data Request No. 059, Attachment B.

b. The components that make up PGE's forecasted FAS 87 pension costs and FAS 106 post-retirement costs are calculated using a long-term forecasting tool provided by PGE's third-party actuary, Willis Towers Watson. Key components included in the calculations are PGE's forecast discount rate and forecast expected return on assets. See PGE's responses to OPUC Data Request Nos. 220 and 221 for additional information on these two components.

April 23, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 223
Dated April 6, 2018

<u>Request:</u>

Regarding the 401(k) Retirement Savings Plan,

a. **Please provide the latest IRS Form 5500 filed including all related schedules.**
b. **Please provide the number of participants or anticipated participants at the end for each year from 2014 through 2019.**
c. **Also, for each year, please provide the following,**
    i. **Number of 401(k) participants who are also participants in the defined benefit pension plan.**
    ii. **Number of 401(k) participants who are not participants in the defined benefit pension plan.**
d. **Please indicate if there are pending or contemplated plan amendments and the nature of such amendments (e.g. match rates, etc.).**
e. **Please explain how the anticipated company contribution of $23.3m in the test year (Mersereau – Neitzke 400/33), was determined including all related work papers and calculations.**

<u>Response:</u>

a. Attachment 223-A provides PGE's 2016 form 5500. PGE expects to file its 2017 form 5500 in October 2018.

b. The table below provides active year-end employee 401(k) participant counts from 2014 (actuals) through 2019 (projected), separated by pension qualified and non-qualified status.

401(k) Participants	2014	2015	2016	2017	2018 (Projected)	2019 (Projected)
Pension qualified	1,756	1,656	1,518	1,387	1,352	1,316
Pension non-qualified	844	990	1,234	1,519	1,617	1,721
Total	**2,600**	**2,646**	**2,752**	**2,906**	**2,969**	**3,037**

c. See part (b) above.

d. The Benefit Administration Committee recently approved some allowed enhancements to Hardship Withdrawal provisions, which PGE will implement in January 2019. These enhancements do not affect plan costs. At this time, there are no other pending plan amendments.

e. Attachment 223-B provides additional details behind the development of the company contribution budget of $23.1 million. The remaining $0.2 million is the cost of outside services for 401(k) education and record keeping fees. The 401(k) company contribution budget for non-bargaining employees assumes a pay increase of 3.5 percent over 2017 levels for each year and a full time employee equivalent (FTE) of 2,191.48 by the end of 2019. The bargaining company contribution budget assumes a 2.5 percent and 3 percent pay increase for 2018 and 2019 respectively and a FTE of 846 by the end of 2019.

Attachment 223-B is protected information and subject to Protective Order No. 18-047.

UE 335

Attachment 223-A

Provided in Electronic Format

2016 Form 5500

UE 335

Attachment 223-B

Provided in Electronic Format

Protected Information Subject to Protective Order No. 18-047

401(k) Company Contribution Budget Work Papers

Form 5500	Annual Return/Report of Employee Benefit Plan	OMB Nos. 1210-0110 1210-0089
Department of the Treasury Internal Revenue Service Department of Labor Employee Benefits Security Administration Pension Benefit Guaranty Corporation	This form is required to be filed for employee benefit plans under sections 104 and 4065 of the Employee Retirement Income Security Act of 1974 (ERISA) and sections 6057(b) and 6058(a) of the Internal Revenue Code (the Code). ▸ **Complete all entries in accordance with the instructions to the Form 5500.**	**2016** **This Form is Open to Public Inspection**

Part I Annual Report Identification Information

For calendar plan year 2016 or fiscal plan year beginning 01/01/2016 and ending 12/31/2016

A This return/report is for:
- ☐ a multiemployer plan
- ☐ a multiple-employer plan (Filers checking this box must attach a list of participating employer information in accordance with the form instructions.)
- ☒ a single-employer plan
- ☐ a DFE (specify) ____

B This return/report is:
- ☐ the first return/report
- ☐ the final return/report
- ☐ an amended return/report
- ☐ a short plan year return/report (less than 12 months)

C If the plan is a collectively-bargained plan, check here. . . . . ▸ ☒

D Check box if filing under:
- ☒ Form 5558
- ☐ automatic extension
- ☐ the DFVC program
- ☐ special extension (enter description)

Part II Basic Plan Information—enter all requested information

1a Name of plan PORTLAND GENERAL ELECTRIC COMPANY 401K PLAN	**1b** Three-digit plan number (PN) ▸ 005 **1c** Effective date of plan 01/01/2005
2a Plan sponsor's name (employer, if for a single-employer plan) Mailing address (include room, apt., suite no. and street, or P.O. Box) City or town, state or province, country, and ZIP or foreign postal code (if foreign, see instructions) PORTLAND GENERAL ELECTRIC COMPANY 121 SW SALMON STREET PORTLAND, OR 97204-2901	**2b** Employer Identification Number (EIN) 93-0256820 **2c** Plan Sponsor's telephone number 503-464-7693 **2d** Business code (see instructions) 221100

Caution: A penalty for the late or incomplete filing of this return/report will be assessed unless reasonable cause is established.

Under penalties of perjury and other penalties set forth in the instructions, I declare that I have examined this return/report, including accompanying schedules, statements and attachments, as well as the electronic version of this return/report, and to the best of my knowledge and belief, it is true, correct, and complete.

SIGN HERE	Filed with authorized/valid electronic signature.	10/13/2017	ANNE MERSEREAU
	Signature of plan administrator	Date	Enter name of individual signing as plan administrator
SIGN HERE			
	Signature of employer/plan sponsor	Date	Enter name of individual signing as employer or plan sponsor
SIGN HERE			
	Signature of DFE	Date	Enter name of individual signing as DFE

Preparer's name (including firm name, if applicable) and address (include room or suite number)	Preparer's telephone number
GRANT THORNTON LLP GRANT THORNTON LLP 171 N. CLARK ST., SUITE 200 CHICAGO, IL 60601	312-856-0200

3a	Plan administrator's name and address [X] Same as Plan Sponsor	**3b** Administrator's EIN	
		3c Administrator's telephone number	
4	If the name and/or EIN of the plan sponsor has changed since the last return/report filed for this plan, enter the name, EIN and the plan number from the last return/report:	**4b** EIN	
a	Sponsor's name	**4c** PN	
5	Total number of participants at the beginning of the plan year	**5**	4342
6	Number of participants as of the end of the plan year unless otherwise stated (welfare plans complete only lines **6a(1), 6a(2), 6b, 6c,** and **6d**).		
a(1)	Total number of active participants at the beginning of the plan year	**6a(1)**	2690
a(2)	Total number of active participants at the end of the plan year	**6a(2)**	2844
b	Retired or separated participants receiving benefits	**6b**	0
c	Other retired or separated participants entitled to future benefits	**6c**	752
d	Subtotal. Add lines **6a(2)**, **6b**, and **6c**.	**6d**	3596
e	Deceased participants whose beneficiaries are receiving or are entitled to receive benefits.	**6e**	36
f	Total. Add lines **6d** and **6e**.	**6f**	3632
g	Number of participants with account balances as of the end of the plan year (only defined contribution plans complete this item)	**6g**	3607
h	Number of participants that terminated employment during the plan year with accrued benefits that were less than 100% vested	**6h**	14
7	Enter the total number of employers obligated to contribute to the plan (only multiemployer plans complete this item)	**7**	

8a If the plan provides pension benefits, enter the applicable pension feature codes from the List of Plan Characteristics Codes in the instructions:

2E 2F 2G 2J 2K 2R 3F

b If the plan provides welfare benefits, enter the applicable welfare feature codes from the List of Plan Characteristics Codes in the instructions:

9a Plan funding arrangement (check all that apply)		**9b** Plan benefit arrangement (check all that apply)	
(1) [X]	Insurance	(1) [X]	Insurance
(2) [ ]	Code section 412(e)(3) insurance contracts	(2) [ ]	Code section 412(e)(3) insurance contracts
(3) [X]	Trust	(3) [X]	Trust
(4) [ ]	General assets of the sponsor	(4) [ ]	General assets of the sponsor

10 Check all applicable boxes in 10a and 10b to indicate which schedules are attached, and, where indicated, enter the number attached. (See instructions)

a Pension Schedules

- (1) [X] **R** (Retirement Plan Information)
- (2) [ ] **MB** (Multiemployer Defined Benefit Plan and Certain Money Purchase Plan Actuarial Information) - signed by the plan actuary
- (3) [ ] **SB** (Single-Employer Defined Benefit Plan Actuarial Information) - signed by the plan actuary

b General Schedules

- (1) [X] **H** (Financial Information)
- (2) [ ] **I** (Financial Information – Small Plan)
- (3) [X] 5 **A** (Insurance Information)
- (4) [X] **C** (Service Provider Information)
- (5) [X] **D** (DFE/Participating Plan Information)
- (6) [ ] **G** (Financial Transaction Schedules)

Part III	Form M-1 Compliance Information (to be completed by welfare benefit plans)

11a If the plan provides welfare benefits, was the plan subject to the Form M-1 filing requirements during the plan year? (See instructions and 29 CFR 2520.101-2.) .... ☐ Yes ☐ No

If "Yes" is checked, complete lines 11b and 11c.

11b Is the plan currently in compliance with the Form M-1 filing requirements? (See instructions and 29 CFR 2520.101-2.) .... ☐ Yes ☐ No

11c Enter the Receipt Confirmation Code for the 2016 Form M-1 annual report. If the plan was not required to file the 2016 Form M-1 annual report, enter the Receipt Confirmation Code for the most recent Form M-1 that was required to be filed under the Form M-1 filing requirements. (Failure to enter a valid Receipt Confirmation Code will subject the Form 5500 filing to rejection as incomplete.)

Receipt Confirmation Code_____________________

SCHEDULE A (Form 5500)	Insurance Information	OMB No. 1210-0110
Department of the Treasury Internal Revenue Service Department of Labor Employee Benefits Security Administration Pension Benefit Guaranty Corporation	This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974 (ERISA). ▶ **File as an attachment to Form 5500.** ▶ Insurance companies are required to provide the information pursuant to ERISA section 103(a)(2).	**2016** **This Form is Open to Public Inspection**

For calendar plan year 2016 or fiscal plan year beginning 01/01/2016 and ending 12/31/2016

A Name of plan PORTLAND GENERAL ELECTRIC COMPANY 401K PLAN	**B** Three-digit plan number (PN) ▶ 005
C Plan sponsor's name as shown on line 2a of Form 5500 PORTLAND GENERAL ELECTRIC COMPANY	**D** Employer Identification Number (EIN) 93-0256820

Part I **Information Concerning Insurance Contract Coverage, Fees, and Commissions** Provide information for each contract on a separate Schedule A. Individual contracts grouped as a unit in Parts II and III can be reported on a single Schedule A.

1 Coverage Information:

(a) Name of insurance carrier
VOYA RETIREMENT AND ANNUITY

(b) EIN	(c) NAIC code	(d) Contract or identification number	(e) Approximate number of persons covered at end of policy or contract year	Policy or contract year (f) From	Policy or contract year (g) To
71-0294708	86509	60342B	3632	01/01/2016	12/31/2016

2 Insurance fee and commission information. Enter the total fees and total commissions paid. List in line 3 the agents, brokers, and other persons in descending order of the amount paid.

(a) Total amount of commissions paid	**(b)** Total amount of fees paid

3 Persons receiving commissions and fees. (Complete as many entries as needed to report all persons).

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid		**(e)** Organization code
	(c) Amount	**(d)** Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid		**(e)** Organization code
	(c) Amount	**(d)** Purpose	

1

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

Part II Investment and Annuity Contract Information

Where individual contracts are provided, the entire group of such individual contracts with each carrier may be treated as a unit for purposes of this report.

4 Current value of plan's interest under this contract in the general account at year end	4	
5 Current value of plan's interest under this contract in separate accounts at year end	5	

6 Contracts With Allocated Funds:

a State the basis of premium rates ▶

b Premiums paid to carrier	6b	
c Premiums due but unpaid at the end of the year	6c	
d If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, enter amount.	6d	

Specify nature of costs ▶

e Type of contract: (1) ☐ individual policies (2) ☐ group deferred annuity

(3) ☐ other (specify) ▶

f If contract purchased, in whole or in part, to distribute benefits from a terminating plan, check here ▶ ☐

7 Contracts With Unallocated Funds (Do not include portions of these contracts maintained in separate accounts)

a Type of contract: (1) ☐ deposit administration (2) ☐ immediate participation guarantee

(3) ☒ guaranteed investment (4) ☐ other ▶

b Balance at the end of the previous year			7b	12129359
c Additions: (1) Contributions deposited during the year	7c(1)			
(2) Dividends and credits	7c(2)			
(3) Interest credited during the year	7c(3)	219496		
(4) Transferred from separate account	7c(4)			
(5) Other (specify below)	7c(5)			
▶				
(6)Total additions			7c(6)	219496
d Total of balance and additions (add lines **7b** and **7c(6)**).			7d	12348855
e Deductions:				
(1) Disbursed from fund to pay benefits or purchase annuities during year	7e(1)	550102		
(2) Administration charge made by carrier	7e(2)			
(3) Transferred to separate account	7e(3)			
(4) Other (specify below)	7e(4)			
▶				
(5) Total deductions			7e(5)	550102
f Balance at the end of the current year (subtract line **7e(5)** from line **7d**)			7f	11798753

Part III Welfare Benefit Contract Information

If more than one contract covers the same group of employees of the same employer(s) or members of the same employee organizations(s), the information may be combined for reporting purposes if such contracts are experience-rated as a unit. Where contracts cover individual employees, the entire group of such individual contracts with each carrier may be treated as a unit for purposes of this report.

8 Benefit and contract type (check all applicable boxes)

a ☐ Health (other than dental or vision) **b** ☐ Dental **c** ☐ Vision **d** ☐ Life insurance
e ☐ Temporary disability (accident and sickness) **f** ☐ Long-term disability **g** ☐ Supplemental unemployment **h** ☐ Prescription drug
i ☐ Stop loss (large deductible) **j** ☐ HMO contract **k** ☐ PPO contract **l** ☐ Indemnity contract
m ☐ Other (specify) ▶

9 Experience-rated contracts:

	Line	Amount	Line	Amount
a Premiums: (1) Amount received	9a(1)			
(2) Increase (decrease) in amount due but unpaid	9a(2)			
(3) Increase (decrease) in unearned premium reserve	9a(3)			
(4) Earned ((1) + (2) - (3))			9a(4)	0
b Benefit charges (1) Claims paid	9b(1)			
(2) Increase (decrease) in claim reserves	9b(2)			
(3) Incurred claims (add (1) and (2))			9b(3)	0
(4) Claims charged			9b(4)	
c Remainder of premium: (1) Retention charges (on an accrual basis) –				
(A) Commissions	9c(1)(A)			
(B) Administrative service or other fees	9c(1)(B)			
(C) Other specific acquisition costs	9c(1)(C)			
(D) Other expenses	9c(1)(D)			
(E) Taxes	9c(1)(E)			
(F) Charges for risks or other contingencies	9c(1)(F)			
(G) Other retention charges	9c(1)(G)			
(H) Total retention			9c(1)(H)	0
(2) Dividends or retroactive rate refunds. (These amounts were ☐ paid in cash, or ☐ credited.)			9c(2)	
d Status of policyholder reserves at end of year: (1) Amount held to provide benefits after retirement			9d(1)	
(2) Claim reserves			9d(2)	
(3) Other reserves			9d(3)	
e Dividends or retroactive rate refunds due. (Do not include amount entered in line 9c(2).)			9e	

10 Nonexperience-rated contracts:

	Line	Amount
a Total premiums or subscription charges paid to carrier	10a	
b If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, other than reported in Part I, line 2 above, report amount.	10b	

Specify nature of costs.

Part IV Provision of Information

11 Did the insurance company fail to provide any information necessary to complete Schedule A? ☐ Yes ☒ No

12 If the answer to line 11 is "Yes," specify the information not provided. ▶

SCHEDULE A (Form 5500)	Insurance Information	OMB No. 1210-0110
Department of the Treasury Internal Revenue Service Department of Labor Employee Benefits Security Administration Pension Benefit Guaranty Corporation	This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974 (ERISA). ▶ **File as an attachment to Form 5500.** ▶ Insurance companies are required to provide the information pursuant to ERISA section 103(a)(2).	**2016** **This Form is Open to Public Inspection**

For calendar plan year 2016 or fiscal plan year beginning 01/01/2016 and ending 12/31/2016

A Name of plan PORTLAND GENERAL ELECTRIC COMPANY 401K PLAN	**B** Three-digit plan number (PN) ▶ 005
C Plan sponsor's name as shown on line 2a of Form 5500 PORTLAND GENERAL ELECTRIC COMPANY	**D** Employer Identification Number (EIN) 93-0256820

Part I **Information Concerning Insurance Contract Coverage, Fees, and Commissions** Provide information for each contract on a separate Schedule A. Individual contracts grouped as a unit in Parts II and III can be reported on a single Schedule A.

1 Coverage Information:

(a) Name of insurance carrier
TRANSAMERICA PREMIER LIFE INSURANCE COMPANY

(b) EIN	(c) NAIC code	(d) Contract or identification number	(e) Approximate number of persons covered at end of policy or contract year	Policy or contract year (f) From	Policy or contract year (g) To
52-0419790	66281	MDA01099TR	3607	01/01/2016	12/31/2016

2 Insurance fee and commission information. Enter the total fees and total commissions paid. List in line 3 the agents, brokers, and other persons in descending order of the amount paid.

(a) Total amount of commissions paid	(b) Total amount of fees paid

3 Persons receiving commissions and fees. (Complete as many entries as needed to report all persons).

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

Part II Investment and Annuity Contract Information

Where individual contracts are provided, the entire group of such individual contracts with each carrier may be treated as a unit for purposes of this report.

4	Current value of plan's interest under this contract in the general account at year end	4	
5	Current value of plan's interest under this contract in separate accounts at year end	5	

6 Contracts With Allocated Funds:

a State the basis of premium rates ▶

b	Premiums paid to carrier	6b	
c	Premiums due but unpaid at the end of the year	6c	
d	If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, enter amount.	6d	

Specify nature of costs ▶

e Type of contract: (1) ☐ individual policies (2) ☐ group deferred annuity

(3) ☐ other (specify) ▶

f If contract purchased, in whole or in part, to distribute benefits from a terminating plan, check here ▶ ☐

7 Contracts With Unallocated Funds (Do not include portions of these contracts maintained in separate accounts)

a Type of contract: (1) ☐ deposit administration (2) ☐ immediate participation guarantee

(3) ☒ guaranteed investment (4) ☐ other ▶

b	Balance at the end of the previous year			7b	29151658
c	Additions: (1) Contributions deposited during the year	7c(1)	2000000		
	(2) Dividends and credits	7c(2)			
	(3) Interest credited during the year	7c(3)	627188		
	(4) Transferred from separate account	7c(4)			
	(5) Other (specify below) ▶	7c(5)			
	(6)Total additions			7c(6)	2627188
d	Total of balance and additions (add lines **7b** and **7c(6)**).			7d	31778846
e	Deductions:				
	(1) Disbursed from fund to pay benefits or purchase annuities during year	7e(1)	1172865		
	(2) Administration charge made by carrier	7e(2)			
	(3) Transferred to separate account	7e(3)			
	(4) Other (specify below) ▶	7e(4)			
	(5) Total deductions			7e(5)	1172865
f	Balance at the end of the current year (subtract line **7e(5)** from line **7d**)			7f	30605981

Part III Welfare Benefit Contract Information

If more than one contract covers the same group of employees of the same employer(s) or members of the same employee organizations(s), the information may be combined for reporting purposes if such contracts are experience-rated as a unit. Where contracts cover individual employees, the entire group of such individual contracts with each carrier may be treated as a unit for purposes of this report.

8 Benefit and contract type (check all applicable boxes)

a ☐ Health (other than dental or vision)	**b** ☐ Dental	**c** ☐ Vision	**d** ☐ Life insurance
e ☐ Temporary disability (accident and sickness)	**f** ☐ Long-term disability	**g** ☐ Supplemental unemployment	**h** ☐ Prescription drug
i ☐ Stop loss (large deductible)	**j** ☐ HMO contract	**k** ☐ PPO contract	**l** ☐ Indemnity contract
m ☐ Other (specify) ▶			

9 Experience-rated contracts:				
a Premiums: (1) Amount received	9a(1)			
(2) Increase (decrease) in amount due but unpaid	9a(2)			
(3) Increase (decrease) in unearned premium reserve	9a(3)			
(4) Earned ((1) + (2) - (3))			9a(4)	0
b Benefit charges (1) Claims paid	9b(1)			
(2) Increase (decrease) in claim reserves	9b(2)			
(3) Incurred claims (add (1) and (2))			9b(3)	0
(4) Claims charged			9b(4)	
c Remainder of premium: (1) Retention charges (on an accrual basis) –				
(A) Commissions	9c(1)(A)			
(B) Administrative service or other fees	9c(1)(B)			
(C) Other specific acquisition costs	9c(1)(C)			
(D) Other expenses	9c(1)(D)			
(E) Taxes	9c(1)(E)			
(F) Charges for risks or other contingencies	9c(1)(F)			
(G) Other retention charges	9c(1)(G)			
(H) Total retention			9c(1)(H)	0
(2) Dividends or retroactive rate refunds. (These amounts were ☐ paid in cash, or ☐ credited.)			9c(2)	
d Status of policyholder reserves at end of year: (1) Amount held to provide benefits after retirement			9d(1)	
(2) Claim reserves			9d(2)	
(3) Other reserves			9d(3)	
e Dividends or retroactive rate refunds due. (Do not include amount entered in line 9c(2).)			9e	
10 Nonexperience-rated contracts:				
a Total premiums or subscription charges paid to carrier			10a	
b If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, other than reported in Part I, line 2 above, report amount.			10b	

Specify nature of costs.

Part IV Provision of Information

11 Did the insurance company fail to provide any information necessary to complete Schedule A? ☐ Yes ☒ No

12 If the answer to line 11 is "Yes," specify the information not provided. ▶

SCHEDULE A (Form 5500)

Department of the Treasury
Internal Revenue Service

Department of Labor
Employee Benefits Security Administration

Pension Benefit Guaranty Corporation

Insurance Information

This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974 (ERISA).

▶ **File as an attachment to Form 5500.**

▶ Insurance companies are required to provide the information pursuant to ERISA section 103(a)(2).

OMB No. 1210-0110

2016

This Form is Open to Public Inspection

For calendar plan year 2016 or fiscal plan year beginning 01/01/2016 and ending 12/31/2016

A Name of plan
PORTLAND GENERAL ELECTRIC COMPANY 401K PLAN

B Three-digit plan number (PN) ▶ 005

C Plan sponsor's name as shown on line 2a of Form 5500
PORTLAND GENERAL ELECTRIC COMPANY

D Employer Identification Number (EIN)
93-0256820

Part I **Information Concerning Insurance Contract Coverage, Fees, and Commissions** Provide information for each contract on a separate Schedule A. Individual contracts grouped as a unit in Parts II and III can be reported on a single Schedule A.

1 Coverage Information:

(a) Name of insurance carrier
VOYA FINANCIAL

(b) EIN	(c) NAIC code	(d) Contract or identification number	(e) Approximate number of persons covered at end of policy or contract year	Policy or contract year (f) From	Policy or contract year (g) To
71-0294708	86509	60342A	3607	01/01/2016	12/31/2016

2 Insurance fee and commission information. Enter the total fees and total commissions paid. List in line 3 the agents, brokers, and other persons in descending order of the amount paid.

(a) Total amount of commissions paid	(b) Total amount of fees paid

3 Persons receiving commissions and fees. (Complete as many entries as needed to report all persons).

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

Part II Investment and Annuity Contract Information

Where individual contracts are provided, the entire group of such individual contracts with each carrier may be treated as a unit for purposes of this report.

4	Current value of plan's interest under this contract in the general account at year end	4	
5	Current value of plan's interest under this contract in separate accounts at year end	5	

6 Contracts With Allocated Funds:

a State the basis of premium rates ▶

b	Premiums paid to carrier	6b	
c	Premiums due but unpaid at the end of the year	6c	
d	If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, enter amount.	6d	

Specify nature of costs ▶

e Type of contract: (1) ☐ individual policies (2) ☐ group deferred annuity

(3) ☐ other (specify) ▶

f If contract purchased, in whole or in part, to distribute benefits from a terminating plan, check here ▶ ☐

7 Contracts With Unallocated Funds (Do not include portions of these contracts maintained in separate accounts)

a Type of contract: (1) ☐ deposit administration (2) ☐ immediate participation guarantee

(3) ☒ guaranteed investment (4) ☐ other ▶

b	Balance at the end of the previous year			7b	17137608
c	Additions: (1) Contributions deposited during the year	7c(1)			
	(2) Dividends and credits	7c(2)			
	(3) Interest credited during the year	7c(3)	312156		
	(4) Transferred from separate account	7c(4)			
	(5) Other (specify below) ▶	7c(5)			
	(6)Total additions			7c(6)	312156
d	Total of balance and additions (add lines **7b** and **7c(6)**).			7d	17449764
e	Deductions:				
	(1) Disbursed from fund to pay benefits or purchase annuities during year	7e(1)	626379		
	(2) Administration charge made by carrier	7e(2)			
	(3) Transferred to separate account	7e(3)			
	(4) Other (specify below) ▶	7e(4)			
	(5) Total deductions			7e(5)	626379
f	Balance at the end of the current year (subtract line **7e(5)** from line **7d**)			7f	16823385

Part III Welfare Benefit Contract Information

If more than one contract covers the same group of employees of the same employer(s) or members of the same employee organizations(s), the information may be combined for reporting purposes if such contracts are experience-rated as a unit. Where contracts cover individual employees, the entire group of such individual contracts with each carrier may be treated as a unit for purposes of this report.

8 Benefit and contract type (check all applicable boxes)

- **a** ☐ Health (other than dental or vision)
- **b** ☐ Dental
- **c** ☐ Vision
- **d** ☐ Life insurance
- **e** ☐ Temporary disability (accident and sickness)
- **f** ☐ Long-term disability
- **g** ☐ Supplemental unemployment
- **h** ☐ Prescription drug
- **i** ☐ Stop loss (large deductible)
- **j** ☐ HMO contract
- **k** ☐ PPO contract
- **l** ☐ Indemnity contract
- **m** ☐ Other (specify) ▶

9 Experience-rated contracts:

a	Premiums: (1) Amount received	**9a(1)**			
	(2) Increase (decrease) in amount due but unpaid	**9a(2)**			
	(3) Increase (decrease) in unearned premium reserve	**9a(3)**			
	(4) Earned ((**1**) + (**2**) - (**3**))			**9a(4)**	0
b	Benefit charges (1) Claims paid	**9b(1)**			
	(2) Increase (decrease) in claim reserves	**9b(2)**			
	(3) Incurred claims (add (**1**) and (**2**))			**9b(3)**	0
	(4) Claims charged			**9b(4)**	
c	Remainder of premium: (1) Retention charges (on an accrual basis) –				
	(A) Commissions	**9c(1)(A)**			
	(B) Administrative service or other fees	**9c(1)(B)**			
	(C) Other specific acquisition costs	**9c(1)(C)**			
	(D) Other expenses	**9c(1)(D)**			
	(E) Taxes	**9c(1)(E)**			
	(F) Charges for risks or other contingencies	**9c(1)(F)**			
	(G) Other retention charges	**9c(1)(G)**			
	(H) Total retention			**9c(1)(H)**	0
	(2) Dividends or retroactive rate refunds. (These amounts were ☐ paid in cash, or ☐ credited.)			**9c(2)**	
d	Status of policyholder reserves at end of year: (1) Amount held to provide benefits after retirement			**9d(1)**	
	(2) Claim reserves			**9d(2)**	
	(3) Other reserves			**9d(3)**	
e	Dividends or retroactive rate refunds due. (Do not include amount entered in line **9c(2)**.)			**9e**	

10 Nonexperience-rated contracts:

a	Total premiums or subscription charges paid to carrier	**10a**	
b	If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, other than reported in Part I, line 2 above, report amount.	**10b**	

Specify nature of costs.

Part IV Provision of Information

11 Did the insurance company fail to provide any information necessary to complete Schedule A? ☐ Yes ☒ No

12 If the answer to line 11 is "Yes," specify the information not provided. ▶

SCHEDULE A
(Form 5500)

Department of the Treasury
Internal Revenue Service

Department of Labor
Employee Benefits Security Administration

Pension Benefit Guaranty Corporation

Insurance Information

This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974 (ERISA).

▶ **File as an attachment to Form 5500.**

▶ Insurance companies are required to provide the information pursuant to ERISA section 103(a)(2).

OMB No. 1210-0110

2016

This Form is Open to Public Inspection

For calendar plan year 2016 or fiscal plan year beginning 01/01/2016 and ending 12/31/2016

A Name of plan
PORTLAND GENERAL ELECTRIC COMPANY 401K PLAN

B Three-digit plan number (PN) ▶ 005

C Plan sponsor's name as shown on line 2a of Form 5500
PORTLAND GENERAL ELECTRIC COMPANY

D Employer Identification Number (EIN)
93-0256820

Part I **Information Concerning Insurance Contract Coverage, Fees, and Commissions** Provide information for each contract on a separate Schedule A. Individual contracts grouped as a unit in Parts II and III can be reported on a single Schedule A.

1 Coverage Information:

(a) Name of insurance carrier
RGA REINSURANCE COMPANY

(b) EIN	(c) NAIC code	(d) Contract or identification number	(e) Approximate number of persons covered at end of policy or contract year	Policy or contract year (f) From	Policy or contract year (g) To
43-1235868	93572	PGECO-0213-01	3607	01/01/2016	12/31/2016

2 Insurance fee and commission information. Enter the total fees and total commissions paid. List in line 3 the agents, brokers, and other persons in descending order of the amount paid.

(a) Total amount of commissions paid	(b) Total amount of fees paid

3 Persons receiving commissions and fees. (Complete as many entries as needed to report all persons).

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid			

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

Part II Investment and Annuity Contract Information

Where individual contracts are provided, the entire group of such individual contracts with each carrier may be treated as a unit for purposes of this report.

4	Current value of plan's interest under this contract in the general account at year end	4	
5	Current value of plan's interest under this contract in separate accounts at year end	5	

6 Contracts With Allocated Funds:

a State the basis of premium rates ▶

b	Premiums paid to carrier	6b	
c	Premiums due but unpaid at the end of the year	6c	
d	If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, enter amount.	6d	

Specify nature of costs ▶

e Type of contract: (1) ☐ individual policies (2) ☐ group deferred annuity

(3) ☐ other (specify) ▶

f If contract purchased, in whole or in part, to distribute benefits from a terminating plan, check here ▶ ☐

7 Contracts With Unallocated Funds (Do not include portions of these contracts maintained in separate accounts)

a Type of contract: (1) ☐ deposit administration (2) ☐ immediate participation guarantee

(3) ☒ guaranteed investment (4) ☐ other ▶

b	Balance at the end of the previous year			7b	29430881
c	Additions: (1) Contributions deposited during the year	7c(1)			
	(2) Dividends and credits	7c(2)			
	(3) Interest credited during the year	7c(3)	578959		
	(4) Transferred from separate account	7c(4)			
	(5) Other (specify below) ▶	7c(5)			
	(6)Total additions			7c(6)	578959
d	Total of balance and additions (add lines **7b** and **7c(6)**).			7d	30009840
e	Deductions:				
	(1) Disbursed from fund to pay benefits or purchase annuities during year	7e(1)	1183577		
	(2) Administration charge made by carrier	7e(2)			
	(3) Transferred to separate account	7e(3)			
	(4) Other (specify below) ▶	7e(4)			
	(5) Total deductions			7e(5)	1183577
f	Balance at the end of the current year (subtract line **7e(5)** from line **7d**)			7f	28826263

Part III Welfare Benefit Contract Information

If more than one contract covers the same group of employees of the same employer(s) or members of the same employee organizations(s), the information may be combined for reporting purposes if such contracts are experience-rated as a unit. Where contracts cover individual employees, the entire group of such individual contracts with each carrier may be treated as a unit for purposes of this report.

8 Benefit and contract type (check all applicable boxes)

a ☐ Health (other than dental or vision) **b** ☐ Dental **c** ☐ Vision **d** ☐ Life insurance
e ☐ Temporary disability (accident and sickness) **f** ☐ Long-term disability **g** ☐ Supplemental unemployment **h** ☐ Prescription drug
i ☐ Stop loss (large deductible) **j** ☐ HMO contract **k** ☐ PPO contract **l** ☐ Indemnity contract
m ☐ Other (specify) ▶

9 Experience-rated contracts:				
a Premiums: (1) Amount received	9a(1)			
(2) Increase (decrease) in amount due but unpaid	9a(2)			
(3) Increase (decrease) in unearned premium reserve	9a(3)			
(4) Earned ((1) + (2) - (3))			9a(4)	0
b Benefit charges (1) Claims paid	9b(1)			
(2) Increase (decrease) in claim reserves	9b(2)			
(3) Incurred claims (add (1) and (2))			9b(3)	0
(4) Claims charged			9b(4)	
c Remainder of premium: (1) Retention charges (on an accrual basis) –				
(A) Commissions	9c(1)(A)			
(B) Administrative service or other fees	9c(1)(B)			
(C) Other specific acquisition costs	9c(1)(C)			
(D) Other expenses	9c(1)(D)			
(E) Taxes	9c(1)(E)			
(F) Charges for risks or other contingencies	9c(1)(F)			
(G) Other retention charges	9c(1)(G)			
(H) Total retention			9c(1)(H)	0
(2) Dividends or retroactive rate refunds. (These amounts were ☐ paid in cash, or ☐ credited.)			9c(2)	
d Status of policyholder reserves at end of year: (1) Amount held to provide benefits after retirement			9d(1)	
(2) Claim reserves			9d(2)	
(3) Other reserves			9d(3)	
e Dividends or retroactive rate refunds due. (Do not include amount entered in line 9c(2).)			9e	
10 Nonexperience-rated contracts:				
a Total premiums or subscription charges paid to carrier			10a	
b If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, other than reported in Part I, line 2 above, report amount.			10b	

Specify nature of costs.

Part IV Provision of Information

11 Did the insurance company fail to provide any information necessary to complete Schedule A? ☐ Yes ☒ No

12 If the answer to line 11 is "Yes," specify the information not provided. ▶

SCHEDULE A (Form 5500)

Department of the Treasury
Internal Revenue Service

Department of Labor
Employee Benefits Security Administration

Pension Benefit Guaranty Corporation

Insurance Information

This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974 (ERISA).

▶ **File as an attachment to Form 5500.**

▶ Insurance companies are required to provide the information pursuant to ERISA section 103(a)(2).

OMB No. 1210-0110

2016

This Form is Open to Public Inspection

For calendar plan year 2016 or fiscal plan year beginning 01/01/2016 and ending 12/31/2016

A Name of plan
PORTLAND GENERAL ELECTRIC COMPANY 401K PLAN

B Three-digit plan number (PN) ▶ 005

C Plan sponsor's name as shown on line 2a of Form 5500
PORTLAND GENERAL ELECTRIC COMPANY

D Employer Identification Number (EIN)
93-0256820

Part I **Information Concerning Insurance Contract Coverage, Fees, and Commissions** Provide information for each contract on a separate Schedule A. Individual contracts grouped as a unit in Parts II and III can be reported on a single Schedule A.

1 Coverage Information:

(a) Name of insurance carrier
THE PRUDENTIAL INSURANCE COMPANY OF AMERICA

(b) EIN	(c) NAIC code	(d) Contract or identification number	(e) Approximate number of persons covered at end of policy or contract year	Policy or contract year (f) From	Policy or contract year (g) To
22-1211670	68241	GA-62461	3607	01/01/2016	12/31/2016

2 Insurance fee and commission information. Enter the total fees and total commissions paid. List in line 3 the agents, brokers, and other persons in descending order of the amount paid.

(a) Total amount of commissions paid	(b) Total amount of fees paid

3 Persons receiving commissions and fees. (Complete as many entries as needed to report all persons).

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid (c) Amount	(d) Purpose	(e) Organization code

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

(a) Name and address of the agent, broker, or other person to whom commissions or fees were paid

(b) Amount of sales and base commissions paid	Fees and other commissions paid		(e) Organization code
	(c) Amount	(d) Purpose	

Part II Investment and Annuity Contract Information

Where individual contracts are provided, the entire group of such individual contracts with each carrier may be treated as a unit for purposes of this report.

4	Current value of plan's interest under this contract in the general account at year end	4	
5	Current value of plan's interest under this contract in separate accounts at year end	5	

6 Contracts With Allocated Funds:

a State the basis of premium rates ▶

b	Premiums paid to carrier	6b	
c	Premiums due but unpaid at the end of the year	6c	
d	If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, enter amount	6d	

Specify nature of costs ▶

e Type of contract: (1) ☐ individual policies (2) ☐ group deferred annuity

(3) ☐ other (specify) ▶

f If contract purchased, in whole or in part, to distribute benefits from a terminating plan, check here ▶ ☐

7 Contracts With Unallocated Funds (Do not include portions of these contracts maintained in separate accounts)

a Type of contract: (1) ☐ deposit administration (2) ☐ immediate participation guarantee

(3) ☒ guaranteed investment (4) ☐ other ▶

b	Balance at the end of the previous year			7b	28993700
c	Additions: (1) Contributions deposited during the year	7c(1)			
	(2) Dividends and credits	7c(2)			
	(3) Interest credited during the year	7c(3)	671963		
	(4) Transferred from separate account	7c(4)			
	(5) Other (specify below) ▶	7c(5)			
	(6)Total additions			7c(6)	671963
d	Total of balance and additions (add lines **7b** and **7c(6)**).			7d	29665663
e	Deductions:				
	(1) Disbursed from fund to pay benefits or purchase annuities during year	7e(1)	1167077		
	(2) Administration charge made by carrier	7e(2)			
	(3) Transferred to separate account	7e(3)			
	(4) Other (specify below) ▶	7e(4)			
	(5) Total deductions			7e(5)	1167077
f	Balance at the end of the current year (subtract line **7e(5)** from line **7d**)			7f	28498586

Part III Welfare Benefit Contract Information

If more than one contract covers the same group of employees of the same employer(s) or members of the same employee organizations(s), the information may be combined for reporting purposes if such contracts are experience-rated as a unit. Where contracts cover individual employees, the entire group of such individual contracts with each carrier may be treated as a unit for purposes of this report.

8 Benefit and contract type (check all applicable boxes)

a ☐ Health (other than dental or vision) **b** ☐ Dental **c** ☐ Vision **d** ☐ Life insurance
e ☐ Temporary disability (accident and sickness) **f** ☐ Long-term disability **g** ☐ Supplemental unemployment **h** ☐ Prescription drug
i ☐ Stop loss (large deductible) **j** ☐ HMO contract **k** ☐ PPO contract **l** ☐ Indemnity contract
m ☐ Other (specify) ▶

9 Experience-rated contracts:		
a Premiums: (1) Amount received	9a(1)	
(2) Increase (decrease) in amount due but unpaid	9a(2)	
(3) Increase (decrease) in unearned premium reserve	9a(3)	
(4) Earned ((1) + (2) - (3))	9a(4)	0
b Benefit charges (1) Claims paid	9b(1)	
(2) Increase (decrease) in claim reserves	9b(2)	
(3) Incurred claims (add (1) and (2))	9b(3)	0
(4) Claims charged	9b(4)	
c Remainder of premium: (1) Retention charges (on an accrual basis) –		
(A) Commissions	9c(1)(A)	
(B) Administrative service or other fees	9c(1)(B)	
(C) Other specific acquisition costs	9c(1)(C)	
(D) Other expenses	9c(1)(D)	
(E) Taxes	9c(1)(E)	
(F) Charges for risks or other contingencies	9c(1)(F)	
(G) Other retention charges	9c(1)(G)	
(H) Total retention	9c(1)(H)	0
(2) Dividends or retroactive rate refunds. (These amounts were ☐ paid in cash, or ☐ credited.)	9c(2)	
d Status of policyholder reserves at end of year: (1) Amount held to provide benefits after retirement	9d(1)	
(2) Claim reserves	9d(2)	
(3) Other reserves	9d(3)	
e Dividends or retroactive rate refunds due. (Do not include amount entered in line **9c(2)**.)	9e	
10 Nonexperience-rated contracts:		
a Total premiums or subscription charges paid to carrier	10a	
b If the carrier, service, or other organization incurred any specific costs in connection with the acquisition or retention of the contract or policy, other than reported in Part I, line 2 above, report amount.	10b	

Specify nature of costs.

Part IV Provision of Information

11 Did the insurance company fail to provide any information necessary to complete Schedule A? ☐ Yes ☒ No

12 If the answer to line 11 is "Yes," specify the information not provided. ▶

SCHEDULE C (Form 5500)	Service Provider Information	OMB No. 1210-0110
Department of the Treasury Internal Revenue Service	This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974 (ERISA).	2016
Department of Labor Employee Benefits Security Administration	▶ **File as an attachment to Form 5500.**	**This Form is Open to Public Inspection.**
Pension Benefit Guaranty Corporation		

For calendar plan year 2016 or fiscal plan year beginning 01/01/2016 and ending 12/31/2016

A Name of plan PORTLAND GENERAL ELECTRIC COMPANY 401K PLAN	**B** Three-digit plan number (PN) ▶ 005
C Plan sponsor's name as shown on line 2a of Form 5500 PORTLAND GENERAL ELECTRIC COMPANY	**D** Employer Identification Number (EIN) 93-0256820

Part I Service Provider Information (see instructions)

You must complete this Part, in accordance with the instructions, to report the information required for **each person** who received, directly or indirectly, $5,000 or more in total compensation (i.e., money or anything else of monetary value) in connection with services rendered to the plan or the person's position with the plan during the plan year. If a person received **only** eligible indirect compensation for which the plan received the required disclosures, you are required to answer line 1 but are not required to include that person when completing the remainder of this Part.

1 Information on Persons Receiving Only Eligible Indirect Compensation

a Check "Yes" or "No" to indicate whether you are excluding a person from the remainder of this Part because they received only eligible indirect compensation for which the plan received the required disclosures (see instructions for definitions and conditions) ☒ Yes ☐ No

b If you answered line 1a "Yes," enter the name and EIN or address of each person providing the required disclosures for the service providers who received only eligible indirect compensation. Complete as many entries as needed (see instructions).

(b) Enter name and EIN or address of person who provided you disclosures on eligible indirect compensation

PRUDENTIAL INSURANCE COMPANY

22-1211670

(b) Enter name and EIN or address of person who provided you disclosures on eligible indirect compensation

RGA

43-1235868

(b) Enter name and EIN or address of person who provided you disclosures on eligible indirect compensation

TRANSAMERICA

95-6140222

(b) Enter name and EIN or address of person who provided you disclosures on eligible indirect compensation

VOYA RETIREMENT & ANNUITY

71-0294708

1

(b) Enter name and EIN or address of person who provided you disclosures on eligible indirect compensation

(b) Enter name and EIN or address of person who provided you disclosures on eligible indirect compensation

(b) Enter name and EIN or address of person who provided you disclosures on eligible indirect compensation

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(b) Enter name and EIN or address of person who provided you disclosures on eligible indirect compensation

(b) Enter name and EIN or address of person who provided you disclosures on eligible indirect compensation

2. Information on Other Service Providers Receiving Direct or Indirect Compensation. Except for those persons for whom you answered "Yes" to line 1a above, complete as many entries as needed to list each person receiving, directly or indirectly, $5,000 or more in total compensation (i.e., money or anything else of value) in connection with services rendered to the plan or their position with the plan during the plan year. (See instructions).

(a) Enter name and EIN or address (see instructions)

VOYA FINANCIAL

71-0294708

(b) Service Code(s)	(c) Relationship to employer, employee organization, or person known to be a party-in-interest	(d) Enter direct compensation paid by the plan. If none, enter -0-.	(e) Did service provider receive indirect compensation? (sources other than plan or plan sponsor)	(f) Did indirect compensation include eligible indirect compensation, for which the plan received the required disclosures?	(g) Enter total indirect compensation received by service provider excluding eligible indirect compensation for which you answered "Yes" to element (f). If none, enter -0-.	(h) Did the service provider give you a formula instead of an amount or estimated amount?
50 99 15	NONE	269758	Yes ☐ No ☒	Yes ☐ No ☐		Yes ☐ No ☐

(a) Enter name and EIN or address (see instructions)

INVESCO CAPITAL MANAGEMENT

58-1707262

(b) Service Code(s)	(c) Relationship to employer, employee organization, or person known to be a party-in-interest	(d) Enter direct compensation paid by the plan. If none, enter -0-.	(e) Did service provider receive indirect compensation? (sources other than plan or plan sponsor)	(f) Did indirect compensation include eligible indirect compensation, for which the plan received the required disclosures?	(g) Enter total indirect compensation received by service provider excluding eligible indirect compensation for which you answered "Yes" to element (f). If none, enter -0-.	(h) Did the service provider give you a formula instead of an amount or estimated amount?
28 50 51	NONE	222287	Yes ☒ No ☐	Yes ☐ No ☒	0	Yes ☐ No ☒

(a) Enter name and EIN or address (see instructions)

MERCER

13-2834414

(b) Service Code(s)	(c) Relationship to employer, employee organization, or person known to be a party-in-interest	(d) Enter direct compensation paid by the plan. If none, enter -0-.	(e) Did service provider receive indirect compensation? (sources other than plan or plan sponsor)	(f) Did indirect compensation include eligible indirect compensation, for which the plan received the required disclosures?	(g) Enter total indirect compensation received by service provider excluding eligible indirect compensation for which you answered "Yes" to element (f). If none, enter -0-.	(h) Did the service provider give you a formula instead of an amount or estimated amount?
28 50 51	NONE	65869	Yes ☐ No ☒	Yes ☐ No ☐		Yes ☐ No ☐

2. Information on Other Service Providers Receiving Direct or Indirect Compensation. Except for those persons for whom you answered "Yes" to line 1a above, complete as many entries as needed to list each person receiving, directly or indirectly, $5,000 or more in total compensation (i.e., money or anything else of value) in connection with services rendered to the plan or their position with the plan during the plan year. (See instructions).

(a) Enter name and EIN or address (see instructions)

GRANT THORNTON LLP

36-6055558

(b) Service Code(s)	(c) Relationship to employer, employee organization, or person known to be a party-in-interest	(d) Enter direct compensation paid by the plan. If none, enter -0-.	(e) Did service provider receive indirect compensation? (sources other than plan or plan sponsor)	(f) Did indirect compensation include eligible indirect compensation, for which the plan received the required disclosures?	(g) Enter total indirect compensation received by service provider excluding eligible indirect compensation for which you answered "Yes" to element (f). If none, enter -0-.	(h) Did the service provider give you a formula instead of an amount or estimated amount?
10 50	NONE	27500	Yes ☐ No ☒	Yes ☐ No ☐		Yes ☐ No ☐

(a) Enter name and EIN or address (see instructions)

VERNON CONSULTING

26-3915791

(b) Service Code(s)	(c) Relationship to employer, employee organization, or person known to be a party-in-interest	(d) Enter direct compensation paid by the plan. If none, enter -0-.	(e) Did service provider receive indirect compensation? (sources other than plan or plan sponsor)	(f) Did indirect compensation include eligible indirect compensation, for which the plan received the required disclosures?	(g) Enter total indirect compensation received by service provider excluding eligible indirect compensation for which you answered "Yes" to element (f). If none, enter -0-.	(h) Did the service provider give you a formula instead of an amount or estimated amount?
50 99 26	NONE	15418	Yes ☐ No ☒	Yes ☐ No ☐		Yes ☐ No ☐

(a) Enter name and EIN or address (see instructions)

GROOM LAW GROUP

52-1219029

(b) Service Code(s)	(c) Relationship to employer, employee organization, or person known to be a party-in-interest	(d) Enter direct compensation paid by the plan. If none, enter -0-.	(e) Did service provider receive indirect compensation? (sources other than plan or plan sponsor)	(f) Did indirect compensation include eligible indirect compensation, for which the plan received the required disclosures?	(g) Enter total indirect compensation received by service provider excluding eligible indirect compensation for which you answered "Yes" to element (f). If none, enter -0-.	(h) Did the service provider give you a formula instead of an amount or estimated amount?
29 50	NONE	5936	Yes ☐ No ☒	Yes ☐ No ☐		Yes ☐ No ☐

Part I Service Provider Information (continued)

3. If you reported on line 2 receipt of indirect compensation, other than eligible indirect compensation, by a service provider, and the service provider is a fiduciary or provides contract administrator, consulting, custodial, investment advisory, investment management, broker, or recordkeeping services, answer the following questions for (a) each source from whom the service provider received $1,000 or more in indirect compensation and (b) each source for whom the service provider gave you a formula used to determine the indirect compensation instead of an amount or estimated amount of the indirect compensation. Complete as many entries as needed to report the required information for each source.

(a) Enter service provider name as it appears on line 2	**(b)** Service Codes (see instructions)	**(c)** Enter amount of indirect compensation

(d) Enter name and EIN (address) of source of indirect compensation	**(e)** Describe the indirect compensation, including any formula used to determine the service provider's eligibility for or the amount of the indirect compensation.

(a) Enter service provider name as it appears on line 2	**(b)** Service Codes (see instructions)	**(c)** Enter amount of indirect compensation

(d) Enter name and EIN (address) of source of indirect compensation	**(e)** Describe the indirect compensation, including any formula used to determine the service provider's eligibility for or the amount of the indirect compensation.

(a) Enter service provider name as it appears on line 2	**(b)** Service Codes (see instructions)	**(c)** Enter amount of indirect compensation

(d) Enter name and EIN (address) of source of indirect compensation	**(e)** Describe the indirect compensation, including any formula used to determine the service provider's eligibility for or the amount of the indirect compensation.

Part II Service Providers Who Fail or Refuse to Provide Information

4 Provide, to the extent possible, the following information for each service provider who failed or refused to provide the information necessary to complete this Schedule.

(a) Enter name and EIN or address of service provider (see instructions)	**(b)** Nature of Service Code(s)	**(c)** Describe the information that the service provider failed or refused to provide

(a) Enter name and EIN or address of service provider (see instructions)	**(b)** Nature of Service Code(s)	**(c)** Describe the information that the service provider failed or refused to provide

(a) Enter name and EIN or address of service provider (see instructions)	**(b)** Nature of Service Code(s)	**(c)** Describe the information that the service provider failed or refused to provide

(a) Enter name and EIN or address of service provider (see instructions)	**(b)** Nature of Service Code(s)	**(c)** Describe the information that the service provider failed or refused to provide

(a) Enter name and EIN or address of service provider (see instructions)	**(b)** Nature of Service Code(s)	**(c)** Describe the information that the service provider failed or refused to provide

(a) Enter name and EIN or address of service provider (see instructions)	**(b)** Nature of Service Code(s)	**(c)** Describe the information that the service provider failed or refused to provide

Part III Termination Information on Accountants and Enrolled Actuaries (see instructions)
(complete as many entries as needed)

a Name:	**b** EIN:
c Position:	
d Address:	**e** Telephone:

Explanation:

a Name:	**b** EIN:
c Position:	
d Address:	**e** Telephone:

Explanation:

a Name:	**b** EIN:
c Position:	
d Address:	**e** Telephone:

Explanation:

a Name:	**b** EIN:
c Position:	
d Address:	**e** Telephone:

Explanation:

a Name:	**b** EIN:
c Position:	
d Address:	**e** Telephone:

Explanation:

SCHEDULE D (Form 5500)
Department of the Treasury
Internal Revenue Service
Department of Labor
Employee Benefits Security Administration

DFE/Participating Plan Information

This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974 (ERISA).

▶ **File as an attachment to Form 5500.**

OMB No. 1210-0110

2016

This Form is Open to Public Inspection.

For calendar plan year 2016 or fiscal plan year beginning 01/01/2016 and ending 12/31/2016

A Name of plan
PORTLAND GENERAL ELECTRIC COMPANY 401K PLAN

B Three-digit plan number (PN) ▶ 005

C Plan or DFE sponsor's name as shown on line 2a of Form 5500
PORTLAND GENERAL ELECTRIC COMPANY

D Employer Identification Number (EIN)
93-0256820

Part I Information on interests in MTIAs, CCTs, PSAs, and 103-12 IEs (to be completed by plans and DFEs)
(Complete as many entries as needed to report all interests in DFEs)

a Name of MTIA, CCT, PSA, or 103-12 IE: SHORT TERM INVESTMENT FUND
b Name of sponsor of entity listed in (a): NORTHERN TRUST COMPANY
c EIN-PN 36-6036794-001 **d** Entity code C **e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 0

a Name of MTIA, CCT, PSA, or 103-12 IE: IGT BLACKROCK CORE FIXED
b Name of sponsor of entity listed in (a): INVESCO NATIONAL TRUST COMPANY
c EIN-PN 61-1246990-224 **d** Entity code C **e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 2860192

a Name of MTIA, CCT, PSA, or 103-12 IE: IGT GOLDMAN SACHS CORE
b Name of sponsor of entity listed in (a): INVESCO NATIONAL TRUST COMPANY
c EIN-PN 61-1246990-223 **d** Entity code C **e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 2866065

a Name of MTIA, CCT, PSA, or 103-12 IE: IGT VOYA SHORT DURATION
b Name of sponsor of entity listed in (a): INVESCO NATIONAL TRUST COMPANY
c EIN-PN 61-1246990-242 **d** Entity code C **e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 16647288

a Name of MTIA, CCT, PSA, or 103-12 IE: IGT INVESCO CORE
b Name of sponsor of entity listed in (a): INVESCO NATIONAL TRUST COMPANY
c EIN-PN 61-1246990-225 **d** Entity code C **e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 9616888

a Name of MTIA, CCT, PSA, or 103-12 IE: IGT INVESCO INT G/C
b Name of sponsor of entity listed in (a): INVESCO NATIONAL TRUST COMPANY
c EIN-PN 61-1246990-212 **d** Entity code C **e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 17911493

a Name of MTIA, CCT, PSA, or 103-12 IE: IGT INVESCO SHRTRM BOND
b Name of sponsor of entity listed in (a): INVESCO NATIONAL TRUST COMPANY
c EIN-PN 61-1246990-215 **d** Entity code C **e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 41058353

a Name of MTIA, CCT, PSA, or 103-12 IE: IGT JENNISON INT G/C		
b Name of sponsor of entity listed in (a): INVESCO NATIONAL TRUST COMPANY		
c EIN-PN 61-1246990-218	**d** Entity code C	**e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 10219747
a Name of MTIA, CCT, PSA, or 103-12 IE: IGT BLACKROCK INT G/C		
b Name of sponsor of entity listed in (a): INVESCO NATIONAL TRUST COMPANY		
c EIN-PN 61-1246990-217	**d** Entity code C	**e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 3002115
a Name of MTIA, CCT, PSA, or 103-12 IE: IGT PIMCO CORE		
b Name of sponsor of entity listed in (a): INVESCO NATIONAL TRUST COMPANY		
c EIN-PN 61-1246990-219	**d** Entity code C	**e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 2880143
a Name of MTIA, CCT, PSA, or 103-12 IE: IGT PIMCO INT G/C		
b Name of sponsor of entity listed in (a): INVESCO NATIONAL TRUST COMPANY		
c EIN-PN 61-1246990-207	**d** Entity code C	**e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 10254342
a Name of MTIA, CCT, PSA, or 103-12 IE: MFO PRUDENTIAL CORE PLUS BOND FUND		
b Name of sponsor of entity listed in (a): PRUDENTIAL TRUST COMPANY		
c EIN-PN 23-6994310-165	**d** Entity code C	**e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions) 15159791
a Name of MTIA, CCT, PSA, or 103-12 IE:		
b Name of sponsor of entity listed in (a):		
c EIN-PN	**d** Entity code	**e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions)
a Name of MTIA, CCT, PSA, or 103-12 IE:		
b Name of sponsor of entity listed in (a):		
c EIN-PN	**d** Entity code	**e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions)
a Name of MTIA, CCT, PSA, or 103-12 IE:		
b Name of sponsor of entity listed in (a):		
c EIN-PN	**d** Entity code	**e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions)
a Name of MTIA, CCT, PSA, or 103-12 IE:		
b Name of sponsor of entity listed in (a):		
c EIN-PN	**d** Entity code	**e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions)
a Name of MTIA, CCT, PSA, or 103-12 IE:		
b Name of sponsor of entity listed in (a):		
c EIN-PN	**d** Entity code	**e** Dollar value of interest in MTIA, CCT, PSA, or 103-12 IE at end of year (see instructions)

Part II	Information on Participating Plans (to be completed by DFEs) (Complete as many entries as needed to report all participating plans)

a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN
a Plan name	
b Name of plan sponsor	**c** EIN-PN

SCHEDULE H (Form 5500) Internal Revenue Service / Department of Labor Employee Benefits Security Administration / Pension Benefit Guaranty Corporation	**Financial Information** This schedule is required to be filed under section 104 of the Employee Retirement Income Security Act of 1974 (ERISA), and section 6058(a) of the Internal Revenue Code (the Code). ▶ **File as an attachment to Form 5500.**	OMB No. 1210-0110 **2016** **This Form is Open to Public Inspection**

For calendar plan year 2016 or fiscal plan year beginning 01/01/2016 and ending 12/31/2016

A Name of plan
PORTLAND GENERAL ELECTRIC COMPANY 401K PLAN

B Three-digit plan number (PN) ▶ 005

C Plan sponsor's name as shown on line 2a of Form 5500
PORTLAND GENERAL ELECTRIC COMPANY

D Employer Identification Number (EIN)
93-0256820

Part I Asset and Liability Statement

1 Current value of plan assets and liabilities at the beginning and end of the plan year. Combine the value of plan assets held in more than one trust. Report the value of the plan's interest in a commingled fund containing the assets of more than one plan on a line-by-line basis unless the value is reportable on lines 1c(9) through 1c(14). Do not enter the value of that portion of an insurance contract which guarantees, during this plan year, to pay a specific dollar benefit at a future date. **Round off amounts to the nearest dollar.** MTIAs, CCTs, PSAs, and 103-12 IEs do not complete lines 1b(1), 1b(2), 1c(8), 1g, 1h, and 1i. CCTs, PSAs, and 103-12 IEs also do not complete lines 1d and 1e. See instructions.

Assets		**(a)** Beginning of Year	**(b)** End of Year
a Total noninterest-bearing cash	**1a**		
b Receivables (less allowance for doubtful accounts):			
(1) Employer contributions	**1b(1)**	601364	1136272
(2) Participant contributions	**1b(2)**	984989	735586
(3) Other	**1b(3)**	123770	242420
c General investments:			
(1) Interest-bearing cash (include money market accounts & certificates of deposit)	**1c(1)**		
(2) U.S. Government securities	**1c(2)**		
(3) Corporate debt instruments (other than employer securities):			
(A) Preferred	**1c(3)(A)**		
(B) All other	**1c(3)(B)**		
(4) Corporate stocks (other than employer securities):			
(A) Preferred	**1c(4)(A)**		
(B) Common	**1c(4)(B)**		
(5) Partnership/joint venture interests	**1c(5)**		
(6) Real estate (other than employer real property)	**1c(6)**		
(7) Loans (other than to participants)	**1c(7)**		
(8) Participant loans	**1c(8)**	9943511	9925125
(9) Value of interest in common/collective trusts	**1c(9)**	130453275	120115623
(10) Value of interest in pooled separate accounts	**1c(10)**		
(11) Value of interest in master trust investment accounts	**1c(11)**		
(12) Value of interest in 103-12 investment entities	**1c(12)**		
(13) Value of interest in registered investment companies (e.g., mutual funds)	**1c(13)**	508787543	563207552
(14) Value of funds held in insurance company general account (unallocated contracts)	**1c(14)**		
(15) Other	**1c(15)**	25828772	27601531

			(a) Beginning of Year	(b) End of Year
1d	Employer-related investments:			
	(1) Employer securities	**1d(1)**		
	(2) Employer real property	**1d(2)**		
e	Buildings and other property used in plan operation	**1e**		
f	Total assets (add all amounts in lines 1a through 1e)	**1f**	676723224	722964109
	Liabilities			
g	Benefit claims payable	**1g**		
h	Operating payables	**1h**	113623	62391
i	Acquisition indebtedness	**1i**		
j	Other liabilities	**1j**		
k	Total liabilities (add all amounts in lines 1g through1j)	**1k**	113623	62391
	Net Assets			
l	Net assets (subtract line 1k from line 1f)	**1l**	676609601	722901718

Part II Income and Expense Statement

2 Plan income, expenses, and changes in net assets for the year. Include all income and expenses of the plan, including any trust(s) or separately maintained fund(s) and any payments/receipts to/from insurance carriers. Round off amounts to the nearest dollar. MTIAs, CCTs, PSAs, and 103-12 IEs do not complete lines 2a, 2b(1)(E), 2e, 2f, and 2g.

	Income		(a) Amount	(b) Total
a	**Contributions:**			
	(1) Received or receivable in cash from: **(A)** Employers	**2a(1)(A)**	18687217	
	(B) Participants	**2a(1)(B)**	24829569	
	(C) Others (including rollovers)	**2a(1)(C)**	3196700	
	(2) Noncash contributions	**2a(2)**		
	(3) Total contributions. Add lines **2a(1)(A), (B), (C),** and line **2a(2)**	**2a(3)**		46713486
b	**Earnings on investments:**			
	(1) Interest:			
	(A) Interest-bearing cash (including money market accounts and certificates of deposit)	**2b(1)(A)**		
	(B) U.S. Government securities	**2b(1)(B)**		
	(C) Corporate debt instruments	**2b(1)(C)**		
	(D) Loans (other than to participants)	**2b(1)(D)**		
	(E) Participant loans	**2b(1)(E)**	402693	
	(F) Other	**2b(1)(F)**	109881	
	(G) Total interest. Add lines **2b(1)(A)** through **(F)**	**2b(1)(G)**		512574
	(2) Dividends: **(A)** Preferred stock	**2b(2)(A)**		
	(B) Common stock	**2b(2)(B)**		
	(C) Registered investment company shares (e.g. mutual funds)	**2b(2)(C)**	11207864	
	(D) Total dividends. Add lines **2b(2)(A), (B),** and **(C)**	**2b(2)(D)**		11207864
	(3) Rents	**2b(3)**		
	(4) Net gain (loss) on sale of assets: **(A)** Aggregate proceeds	**2b(4)(A)**		
	(B) Aggregate carrying amount (see instructions)	**2b(4)(B)**		
	(C) Subtract line **2b(4)(B)** from line **2b(4)(A)** and enter result	**2b(4)(C)**		0
	(5) Unrealized appreciation (depreciation) of assets: **(A)** Real estate	**2b(5)(A)**		
	(B) Other	**2b(5)(B)**	-1032948	
	(C) Total unrealized appreciation of assets. Add lines **2b(5)(A)** and **(B)**	**2b(5)(C)**		-1032948

		(a) Amount	(b) Total
(6) Net investment gain (loss) from common/collective trusts	2b(6)		2186357
(7) Net investment gain (loss) from pooled separate accounts	2b(7)		
(8) Net investment gain (loss) from master trust investment accounts	2b(8)		
(9) Net investment gain (loss) from 103-12 investment entities	2b(9)		
(10) Net investment gain (loss) from registered investment companies (e.g., mutual funds)	2b(10)		34637470
c Other income	2c		
d Total income. Add all **income** amounts in column (b) and enter total	2d		94224803
Expenses			
e Benefit payment and payments to provide benefits:			
(1) Directly to participants or beneficiaries, including direct rollovers	2e(1)	46591357	
(2) To insurance carriers for the provision of benefits	2e(2)		
(3) Other	2e(3)		
(4) Total benefit payments. Add lines **2e(1)** through **(3)**	2e(4)		46591357
f Corrective distributions (see instructions)	2f		
g Certain deemed distributions of participant loans (see instructions)	2g		
h Interest expense	2h		
i Administrative expenses: **(1)** Professional fees	2i(1)	33436	
(2) Contract administrator fees	2i(2)		
(3) Investment advisory and management fees	2i(3)	492045	
(4) Other	2i(4)	815848	
(5) Total administrative expenses. Add lines **2i(1)** through **(4)**	2i(5)		1341329
j Total expenses. Add all **expense** amounts in column (b) and enter total	2j		47932686
Net Income and Reconciliation			
k Net income (loss). Subtract line **2j** from line **2d**	2k		46292117
l Transfers of assets:			
(1) To this plan	2l(1)		
(2) From this plan	2l(2)		

Part III Accountant's Opinion

3 Complete lines 3a through 3c if the opinion of an independent qualified public accountant is attached to this Form 5500. Complete line 3d if an opinion is not attached.

a The attached opinion of an independent qualified public accountant for this plan is (see instructions):

(1) ☐ Unqualified (2) ☐ Qualified (3) ☒ Disclaimer (4) ☐ Adverse

b Did the accountant perform a limited scope audit pursuant to 29 CFR 2520.103-8 and/or 103-12(d)? ☒ Yes ☐ No

c Enter the name and EIN of the accountant (or accounting firm) below:

(1) Name: GRANT THORNTON LLP (2) EIN: 36-6055558

d The opinion of an independent qualified public accountant is **not attached** because:

(1) ☐ This form is filed for a CCT, PSA, or MTIA. (2) ☐ It will be attached to the next Form 5500 pursuant to 29 CFR 2520.104-50.

Part IV Compliance Questions

4 CCTs and PSAs do not complete Part IV. MTIAs, 103-12 IEs, and GIAs do not complete lines 4a, 4e, 4f, 4g, 4h, 4k, 4m, 4n, or 5. 103-12 IEs also do not complete lines 4j and 4l. MTIAs also do not complete line 4l.

During the plan year:		Yes	No	Amount
a Was there a failure to transmit to the plan any participant contributions within the time period described in 29 CFR 2510.3-102? Continue to answer "Yes" for any prior year failures until fully corrected. (See instructions and DOL's Voluntary Fiduciary Correction Program.)	4a		X	
b Were any loans by the plan or fixed income obligations due the plan in default as of the close of the plan year or classified during the year as uncollectible? Disregard participant loans secured by participant's account balance. (Attach Schedule G (Form 5500) Part I if "Yes" is checked.)	4b		X	

1

			Yes	No	Amount
c	Were any leases to which the plan was a party in default or classified during the year as uncollectible? (Attach Schedule G (Form 5500) Part II if "Yes" is checked.)	4c		X	
d	Were there any nonexempt transactions with any party-in-interest? (Do not include transactions reported on line 4a. Attach Schedule G (Form 5500) Part III if "Yes" is checked.)	4d		X	
e	Was this plan covered by a fidelity bond?	4e	X		10000000
f	Did the plan have a loss, whether or not reimbursed by the plan's fidelity bond, that was caused by fraud or dishonesty?	4f		X	
g	Did the plan hold any assets whose current value was neither readily determinable on an established market nor set by an independent third party appraiser?	4g		X	
h	Did the plan receive any noncash contributions whose value was neither readily determinable on an established market nor set by an independent third party appraiser?	4h		X	
i	Did the plan have assets held for investment? (Attach schedule(s) of assets if "Yes" is checked, and see instructions for format requirements.)	4i	X		
j	Were any plan transactions or series of transactions in excess of 5% of the current value of plan assets? (Attach schedule of transactions if "Yes" is checked, and see instructions for format requirements.)	4j		X	
k	Were all the plan assets either distributed to participants or beneficiaries, transferred to another plan, or brought under the control of the PBGC?	4k		X	
l	Has the plan failed to provide any benefit when due under the plan?	4l		X	
m	If this is an individual account plan, was there a blackout period? (See instructions and 29 CFR 2520.101-3.)	4m		X	
n	If 4m was answered "Yes," check the "Yes" box if you either provided the required notice or one of the exceptions to providing the notice applied under 29 CFR 2520.101-3	4n			
o	Defined Benefit Plan or Money Purchase Pension Plan Only: Were any distributions made during the plan year to an employee who attained age 62 and had not separated from service?	4o			

5a Has a resolution to terminate the plan been adopted during the plan year or any prior plan year? If "Yes," enter the amount of any plan assets that reverted to the employer this year. ☐ Yes ☒ No **Amount:**

5b If, during this plan year, any assets or liabilities were transferred from this plan to another plan(s), identify the plan(s) to which assets or liabilities were transferred. (See instructions.)

5b(1) Name of plan(s)	**5b(2)** EIN(s)	**5b(3)** PN(s)

5c If the plan is a defined benefit plan, is it covered under the PBGC insurance program (See ERISA section 4021.)? ☐ Yes ☐ No ☐ Not determined
If "Yes" is checked, enter the My PAA confirmation number from the PBGC premium filing for this plan year__________________. (See instructions.)

Part V Trust Information

6a Name of trust	**6b** Trust's EIN

6c Name of trustee or custodian	**6d** Trustee's or custodian's telephone number

SCHEDULE R
(Form 5500)

Department of the Treasury
Internal Revenue Service

Department of Labor
Employee Benefits Security Administration

Pension Benefit Guaranty Corporation

Retirement Plan Information

This schedule is required to be filed under sections 104 and 4065 of the Employee Retirement Income Security Act of 1974 (ERISA) and section 6058(a) of the Internal Revenue Code (the Code).

▶ **File as an attachment to Form 5500.**

OMB No. 1210-0110

2016

This Form is Open to Public Inspection.

For calendar plan year 2016 or fiscal plan year beginning 01/01/2016 and ending 12/31/2016

A Name of plan
PORTLAND GENERAL ELECTRIC COMPANY 401K PLAN

B Three-digit plan number (PN) ▶ 005

C Plan sponsor's name as shown on line 2a of Form 5500
PORTLAND GENERAL ELECTRIC COMPANY

D Employer Identification Number (EIN)
93-0256820

Part I Distributions

All references to distributions relate only to payments of benefits during the plan year.

1 Total value of distributions paid in property other than in cash or the forms of property specified in the instructions **1** 0

2 Enter the EIN(s) of payor(s) who paid benefits on behalf of the plan to participants or beneficiaries during the year (if more than two, enter EINs of the two payors who paid the greatest dollar amounts of benefits):

EIN(s): 36-6036794 ____________

Profit-sharing plans, ESOPs, and stock bonus plans, skip line 3.

3 Number of participants (living or deceased) whose benefits were distributed in a single sum, during the plan year **3**

Part II Funding Information (If the plan is not subject to the minimum funding requirements of section of 412 of the Internal Revenue Code or ERISA section 302, skip this Part.)

4 Is the plan administrator making an election under Code section 412(d)(2) or ERISA section 302(d)(2)? .... ☐ Yes ☐ No ☐ N/A

If the plan is a defined benefit plan, go to line 8.

5 If a waiver of the minimum funding standard for a prior year is being amortized in this plan year, see instructions and enter the date of the ruling letter granting the waiver. **Date:** Month ________ Day ________ Year ________

If you completed line 5, complete lines 3, 9, and 10 of Schedule MB and do not complete the remainder of this schedule.

6 a Enter the minimum required contribution for this plan year (include any prior year accumulated funding deficiency not waived) **6a**

b Enter the amount contributed by the employer to the plan for this plan year **6b**

c Subtract the amount in line 6b from the amount in line 6a. Enter the result (enter a minus sign to the left of a negative amount) **6c**

If you completed line 6c, skip lines 8 and 9.

7 Will the minimum funding amount reported on line 6c be met by the funding deadline? .... ☐ Yes ☐ No ☐ N/A

8 If a change in actuarial cost method was made for this plan year pursuant to a revenue procedure or other authority providing automatic approval for the change or a class ruling letter, does the plan sponsor or plan administrator agree with the change? .... ☐ Yes ☐ No ☐ N/A

Part III Amendments

9 If this is a defined benefit pension plan, were any amendments adopted during this plan year that increased or decreased the value of benefits? If yes, check the appropriate box. If no, check the "No" box. .... ☐ Increase ☐ Decrease ☐ Both ☐ No

Part IV ESOPs (see instructions). If this is not a plan described under Section 409(a) or 4975(e)(7) of the Internal Revenue Code, skip this Part.

10 Were unallocated employer securities or proceeds from the sale of unallocated securities used to repay any exempt loan? .... ☐ Yes ☐ No

11 a Does the ESOP hold any preferred stock? .... ☐ Yes ☐ No

b If the ESOP has an outstanding exempt loan with the employer as lender, is such loan part of a "back-to-back" loan? (See instructions for definition of "back-to-back" loan.) .... ☐ Yes ☐ No

12 Does the ESOP hold any stock that is not readily tradable on an established securities market? .... ☐ Yes ☐ No

Part V Additional Information for Multiemployer Defined Benefit Pension Plans

13 Enter the following information for each employer that contributed more than 5% of total contributions to the plan during the plan year (measured in dollars). See instructions. *Complete as many entries as needed to report all applicable employers.*

a Name of contributing employer

b EIN **c** Dollar amount contributed by employer

d Date collective bargaining agreement expires *(If employer contributes under more than one collective bargaining agreement, check box* ☐ *and see instructions regarding required attachment. Otherwise, enter the applicable date.)* Month _______ Day _______ Year _______

e Contribution rate information *(If more than one rate applies, check this box* ☐ *and see instructions regarding required attachment. Otherwise, complete lines 13e(1) and 13e(2).)*
(1) Contribution rate (in dollars and cents) ____________
(2) Base unit measure: ☐ Hourly ☐ Weekly ☐ Unit of production ☐ Other (specify):

a Name of contributing employer

b EIN **c** Dollar amount contributed by employer

d Date collective bargaining agreement expires *(If employer contributes under more than one collective bargaining agreement, check box* ☐ *and see instructions regarding required attachment. Otherwise, enter the applicable date.)* Month _______ Day _______ Year _______

e Contribution rate information *(If more than one rate applies, check this box* ☐ *and see instructions regarding required attachment. Otherwise, complete lines 13e(1) and 13e(2).)*
(1) Contribution rate (in dollars and cents) ____________
(2) Base unit measure: ☐ Hourly ☐ Weekly ☐ Unit of production ☐ Other (specify): ______________________________

a Name of contributing employer

b EIN **c** Dollar amount contributed by employer

d Date collective bargaining agreement expires *(If employer contributes under more than one collective bargaining agreement, check box* ☐ *and see instructions regarding required attachment. Otherwise, enter the applicable date.)* Month _______ Day _______ Year _______

e Contribution rate information *(If more than one rate applies, check this box* ☐ *and see instructions regarding required attachment. Otherwise, complete lines 13e(1) and 13e(2).)*
(1) Contribution rate (in dollars and cents) ____________
(2) Base unit measure: ☐ Hourly ☐ Weekly ☐ Unit of production ☐ Other (specify): ______________________________

a Name of contributing employer

b EIN **c** Dollar amount contributed by employer

d Date collective bargaining agreement expires *(If employer contributes under more than one collective bargaining agreement, check box* ☐ *and see instructions regarding required attachment. Otherwise, enter the applicable date.)* Month _______ Day _______ Year _______

e Contribution rate information *(If more than one rate applies, check this box* ☐ *and see instructions regarding required attachment. Otherwise, complete lines 13e(1) and 13e(2).)*
(1) Contribution rate (in dollars and cents) ____________
(2) Base unit measure: ☐ Hourly ☐ Weekly ☐ Unit of production ☐ Other (specify): ______________________________

a Name of contributing employer

b EIN **c** Dollar amount contributed by employer

d Date collective bargaining agreement expires *(If employer contributes under more than one collective bargaining agreement, check box* ☐ *and see instructions regarding required attachment. Otherwise, enter the applicable date.)* Month _______ Day _______ Year _______

e Contribution rate information *(If more than one rate applies, check this box* ☐ *and see instructions regarding required attachment. Otherwise, complete lines 13e(1) and 13e(2).)*
(1) Contribution rate (in dollars and cents) ____________
(2) Base unit measure: ☐ Hourly ☐ Weekly ☐ Unit of production ☐ Other (specify): ______________________________

a Name of contributing employer

b EIN **c** Dollar amount contributed by employer

d Date collective bargaining agreement expires *(If employer contributes under more than one collective bargaining agreement, check box* ☐ *and see instructions regarding required attachment. Otherwise, enter the applicable date.)* Month _______ Day _______ Year _______

e Contribution rate information *(If more than one rate applies, check this box* ☐ *and see instructions regarding required attachment. Otherwise, complete lines 13e(1) and 13e(2).)*
(1) Contribution rate (in dollars and cents) ____________
(2) Base unit measure: ☐ Hourly ☐ Weekly ☐ Unit of production ☐ Other (specify): ______________________________

14 Enter the number of participants on whose behalf no contributions were made by an employer as an employer of the participant for:		
a The current year	**14a**	
b The plan year immediately preceding the current plan year	**14b**	
c The second preceding plan year	**14c**	
15 Enter the ratio of the number of participants under the plan on whose behalf no employer had an obligation to make an employer contribution during the current plan year to:		
a The corresponding number for the plan year immediately preceding the current plan year	**15a**	
b The corresponding number for the second preceding plan year	**15b**	
16 Information with respect to any employers who withdrew from the plan during the preceding plan year:		
a Enter the number of employers who withdrew during the preceding plan year	**16a**	
b If line 16a is greater than 0, enter the aggregate amount of withdrawal liability assessed or estimated to be assessed against such withdrawn employers	**16b**	

17 If assets and liabilities from another plan have been transferred to or merged with this plan during the plan year, check box and see instructions regarding supplemental information to be included as an attachment. ☐

Part VI Additional Information for Single-Employer and Multiemployer Defined Benefit Pension Plans

18 If any liabilities to participants or their beneficiaries under the plan as of the end of the plan year consist (in whole or in part) of liabilities to such participants and beneficiaries under two or more pension plans as of immediately before such plan year, check box and see instructions regarding supplemental information to be included as an attachment ☐

19 If the total number of participants is 1,000 or more, complete lines (a) through (c)

a Enter the percentage of plan assets held as:
Stock: ______% Investment-Grade Debt: ______% High-Yield Debt: ______% Real Estate: ______% Other: ______%

b Provide the average duration of the combined investment-grade and high-yield debt:
☐ 0-3 years ☐ 3-6 years ☐ 6-9 years ☐ 9-12 years ☐ 12-15 years ☐ 15-18 years ☐ 18-21 years ☐ 21 years or more

c What duration measure was used to calculate line 19(b)?
☐ Effective duration ☐ Macaulay duration ☐ Modified duration ☐ Other (specify):

Part VII IRS Compliance Questions

20a Is the plan a 401(k) plan? If "No," skip b	☐ Yes ☐ No
20b How did the plan satisfy the nondiscrimination requirements for employee deferrals under section 401(k)(3) for the plan year? Check all that apply:	☐ Design-based safe harbor ☐ "Prior year" ADP test ☐ "Current year" ADP test ☐ N/A
21a What testing method was used to satisfy the coverage requirements under section 410(b) for the plan year? Check all that apply:	☐ Ratio percentage test ☐ Average benefit test ☐ N/A
21b Did the plan satisfy the coverage and nondiscrimination requirements of sections 410(b) and 401(a)(4) for the plan year by combining this plan with any other plan under the permissive aggregation rules?	☐ Yes ☐ No

22a If the plan is a master and prototype plan (M&P) or volume submitter plan that received a favorable IRS opinion letter or advisory letter, enter the date of the letter _____/_____/_____ and the serial number ______________.

22b If the plan is an individually-designed plan that received a favorable determination letter from the IRS, enter the date of the most recent determination letter / / .

Grant Thornton

Financial Statements and Report of Independent Certified Public Accountants

Portland General Electric Company 401(k) Plan

December 31, 2016 and 2015

Contents

Grant Thornton

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

Grant Thornton LLP
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Trustees and Participants
Portland General Electric Company 401(k) Plan

Report on the financial statements

We have audited the accompanying financial statements of Portland General Electric Company 401(k) Plan (the "Plan"), which comprise the statements of net assets available for benefits as of December 31, 2016 and 2015, and the related statements of changes in net assets available for benefits for the years then ended, and the related notes to the financial statements.

Management's responsibility for the financial statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Because of the matter described in the Basis for Disclaimer of Opinion paragraph, however, we were not able to obtain sufficient appropriate audit evidence to provide a basis for an audit opinion.

Basis for disclaimer of opinion
As permitted by 29 CFR 2520.103-8 of the Department of Labor's Rules and Regulations for Reporting and Disclosure under the Employee Retirement Income Security Act of 1974, the Plan administrator instructed us not to perform, and we did not perform, any auditing procedures with respect to the certified information described in Note C, except for comparing such information with the related information included in the financial statements. We have been informed by the Plan administrator that the certifying entities meet the requirements of 29 CFR 2520.103-8. The Plan administrator obtained a certification from these entities as of December 31, 2016 and 2015, and for the years then ended, stating that the certified information provided to the Plan administrator is complete and accurate.

Disclaimer of opinion

Because of the significance of the matter described in the Basis for Disclaimer of Opinion paragraph, we have not been able to obtain sufficient appropriate audit evidence to provide a basis for an audit opinion. Accordingly, we do not express an opinion on these financial statements.

Supplementary information

The supplemental schedule, Schedule H, Part IV, Line 4i -Schedule of Assets (Held at End of Year) as of December 31, 2016 is presented for purposes of additional analysis and is not a required part of the financial statements, but is supplementary information required by the Department of Labor's Rules and Regulations for Reporting and Disclosure under the Employee Retirement Income Security Act of 1974. Because of the significance of the matter described in the Basis for Disclaimer of Opinion paragraph, we do not express an opinion on the supplemental schedule.

Report on form and content in compliance with DOL rules and regulations

The form and content of the information included in the financial statements and supplemental schedules, other than that derived from the certified information described in Note C, have been audited by us in accordance with auditing standards generally accepted in the United States of America and, in our opinion, are presented in compliance with the Department of Labor's Rules and Regulations for Reporting and Disclosure under the Employee Retirement Income Security Act of 1974.

Grant Thornton LLP

Portland, Oregon
October 6, 2017

Portland General Electric Company 401(k) Plan

STATEMENTS OF NET ASSETS AVAILABLE FOR BENEFITS

December 31,

	2016	2015
ASSETS		
Investments:		
Participant-directed investments	$ 710,924,706	$ 665,069,590
Total investments	710,924,706	665,069,590
Receivables:		
Notes receivable from participants	9,985,455	9,983,055
Employer contributions	1,136,272	601,364
Participant contributions	735,586	984,989
Accrued income	242,420	123,770
Total receivables	12,099,733	11,693,178
Total assets	723,024,439	676,762,768
LIABILITIES		
Administrative fees payable	62,391	113,623
Total liabilities	62,391	113,623
Net assets available for benefits	$ 722,962,048	$ 676,649,145

The accompanying notes are an integral part of these financial statements.

Portland General Electric Company 401(k) Plan

STATEMENTS OF CHANGES IN NET ASSETS AVAILABLE FOR BENEFITS

Years ended December 31,

	2016	2015
Additions:		
Contributions:		
Participant	$ 24,829,569	$ 24,105,620
Employer	18,687,217	16,354,883
Participant rollover	3,196,700	1,455,063
Total contributions	46,713,486	41,915,566
Investment income (loss):		
Dividend and interest income	11,317,745	13,287,377
Net appreciation(depreciation) in fair value of investments	35,790,879	(13,921,055)
Net investment income	47,108,624	(633,678)
Interest income on notes receivable from participants	423,479	417,878
Total additions	94,245,589	41,699,766
Deductions:		
Benefits paid to participants	46,591,357	48,498,018
Administrative expenses	1,341,329	1,168,518
Total deductions	47,932,686	49,666,536
Increase (decrease) in net assets	46,312,903	(7,966,770)
Net assets available for benefits:		
Beginning of year	676,649,145	684,615,915
End of year	$ 722,962,048	$ 676,649,145

The accompanying notes are an integral part of these financial statements.

NOTE A – DESCRIPTION OF PLAN

The following description of the Portland General Electric Company 401(k) Plan (the "Plan") is provided for general information purposes only. Participants should refer to the Plan document for more complete information.

General — The Plan is a defined contribution plan covering substantially all employees of Portland General Electric Company ("PGE," the "Company", or the "Plan Sponsor"). The Benefits Administration Committee controls and manages the operation and administration of the Plan. The Investment Committee is responsible for selecting and monitoring the Plan's investment fund options. Voya Institutional Trust Company (the "Trustee") served as the trustee of the Plan as of December 31, 2016 and 2015, and for the year ended December 31, 2016 and the six months ended December 31, 2015. The Northern Trust Company (the "Trustee") served as the trustee of the Plan as of and for the six months ended June 30, 2015. Voya Institutional Trust Company is the Plan's record keeper as of December 31, 2016 and 2015. The Plan is subject to the provisions of the Employee Retirement Income Security Act of 1974 (ERISA). On January 1, 2016, the Plan was restated to incorporate prior amendments and make minor clarifying changes.

Eligibility — All regular and temporary employees of the Company are eligible to participate in the Plan.

Automatic Enrollment — After 60 days of employment, all new hire employees are automatically enrolled into the Plan with a 6% participant contribution, providing they did not opt out of the Plan. The participant's contribution percentage is increased each year in May by 1% until 15% is reached, unless otherwise directed by the participant. In the absence of an investment election by the participant, the contribution and match is invested into the target date retirement fund based on the participant's age.

Employee Contributions — All employees, either regular or temporary, may contribute up to 50% of their base salary and 100% of their annual bonus to the Plan, subject to certain Internal Revenue Code ("IRC") limitations. Employees who contribute on a before tax or Roth basis receive a match on the combined contribution at the time it is made. Employee contributions to the Plan are immediately fully vested.

Company Match and Profit Share Contributions — The Company contribution that employees receive under the Plan depends on which of the following groups they belong to:

Non-Bargaining Retirement Plan A — Employees hired or re-hired as non-bargaining employees before February 1, 2009.

Bargaining Unit 1 ("BU1") Retirement Plan A — Bargaining unit employees (not including those who work at the Company's Coyote Springs and Port Westward power plants) hired before January 1, 1999 and born before January 2, 1957.

Bargaining Unit 2 ("BU2") Retirement Plan A — Bargaining unit employees who work at Coyote Springs, Carty and Port Westward power plants hired before January 1, 2012.

Bargaining Unit 2 ("BU2") Retirement Plan C — Bargaining unit employees who work at Coyote Springs, Carty and Port Westward power plants hired or rehired on or after January 1, 2012.

NOTE A – DESCRIPTION OF PLAN, Continued

BU1 Retirement Plan B — Bargaining unit employees (not including those who work at the Company's Coyote Springs and Port Westward power plants) (i) hired on or after January 1, 1999; or (ii) hired before January 1, 1999 but born after January 1, 1957; or (iii) who were eligible for Retirement Plan A but who elected to participate in Retirement Plan B by February 28, 2009.

Non-Bargaining Retirement Plan C — Non-bargaining employees hired or rehired on or after February 1, 2009.

The table below summarizes Company contributions to the Plan for plan years 2016 and 2015:

	Match	Profit Share
Non-Bargaining Retirement Plan A and BU2 Retirement Plan A (hired before January 1, 2012)	Up to 6% of pay	N/A
BU2 Retirement Plan C (hired or rehired on or after January 1, 2012)	Up to 5% of pay	5% of pay
Non-Bargaining Retirement Plan C	Up to 5% of pay	5% of pay
BU1 Retirement Plan A	Up to 6% of pay	1% of pay effective March 3, 2010
BU1 Retirement Plan B	Up to 5% of pay	6% of pay effective March 3, 2010

Participant Accounts — Individual accounts are maintained for each Plan participant. Each participant's account is credited with the participant's contributions, the Company's matching and profit share contributions, investment earnings less charges for administrative expenses, and reduced by any distributions. Participants may also contribute amounts representing distributions from other qualified defined benefit or defined contribution plans through a rollover contribution to the Plan.

Investments — Participants direct the investment of their contributions into various investment options offered by the Plan. Company contributions are invested in the same funds as the participant contributions. The Plan currently offers mutual funds, premixed portfolios, a stable value fund and a self-directed brokerage account as investment options for participants.

The following is a description of the Plan's investment fund options:

a. The Self-Directed Brokerage Account (SDBA) is a personal brokerage account that allows the participant to invest in publicly-traded securities except securities of the Company and the core funds of the Plan.

b. The Stable Value Fund (SVF) invests in a diversified portfolio of high quality, stable value investments that offer stability and liquidity. Investments in this fund include guaranteed investment contracts (GICs) issued by major high quality insurance companies and other stable value contracts. These investments provide a fixed rate of return for a specified time period and are fully benefit responsive.

NOTE A – DESCRIPTION OF PLAN, Continued

c. The Diversified Bond Fund seeks to provide high current income consistent with long-term preservation of capital by investing primarily in high-quality bonds, inflation-indexed securities and high-yield instruments. Capital appreciation is a secondary objective.

d. The Vanguard Total Bond Market Index Fund is designed to provide broad exposure to U.S. investment grade bonds. Reflecting this goal, the fund invests about 30% in corporate bonds and 70% in U.S. government bonds of all maturities.

e. The Large Cap Fund seek to provide long-term growth of capital by investing primarily in the stocks of large U.S. companies, as represented by the Russell 1000 index.

f. The Vanguard Institutional Index Fund seeks to track the performance of a benchmark index that measures the investment return of large-capitalization stocks. The fund attempts to replicate the target index by investing assets in the stocks that make up Standard and Poor's 500 index, which is a widely recognized benchmark of U.S. stock market performance that is dominated by the stocks of large U.S. companies.

g. The International Equity Fund seeks to provide long-term growth of capital and future income by investing primarily in stocks of large companies based outside the U.S. and to outperform the MSCI ACWI Ex-US international equity benchmark over a market cycle.

h. The Vanguard International Equity Fund employs an indexing investment approach designed to track the performance of the FTSE Global All Cap ex US Index, which includes approximately common stocks of companies located in developed countries of Europe, Australia, Asia, and the Far East. The Fund attempts to replicate the target index by investing all, or substantially all, of its assets in the stocks that make up the Index, holding each stock in approximately the same proportion as its weighting in the Index.

i. The SMID Cap Equity Fund seeks to provide long-term capital appreciation by investing primarily in stocks of small to mid-size U.S. companies, as represented by the Russell 2500 index.

j. The T. Rowe Price Target Date Retirement Funds are pre-mixed portfolios which provide diversified exposure to stocks, bonds and cash for those investors with a specific retirement date. The funds invest in T. Rowe Price mutual funds as the underlying investment vehicle.

k. The Vanguard Extended Market Index Fund employs an indexing investment approach designed to track the performance of the Standard and Poor's Completion Index, a broadly diversified index of stocks of small and mid-size U.S. companies. The S&P Completion Index contains all of the U.S. common stocks regularly traded on the New York Stock Exchange and the NASDAQ over-the-counter market, except those stocks included in the S&P 500 Index. The fund invests all, or substantially all, of its assets in stocks of its target index, with nearly 80% of its assets invested in approximately 1,200 of the stocks in its target index (covering nearly 85% of the Index's total market capitalization), and the rest of its assets in a representative sample of the remaining stocks.

l. The JPMorgan Diversified Real Return Fund is a fund of funds that seeks real return by allocating its assets across inflation-sensitive asset classes.

m. The DFA Emerging Markets Core Equity Fund purchases a broad and diverse group of securities associated with emerging markets, which may include frontier markets (emerging market countries in an earlier stage of development), with an increased exposure to securities of small cap issuers and securities that it considers to be value securities.

NOTE A – DESCRIPTION OF PLAN, Continued

Vesting — Participants are vested immediately in their contributions and actual earnings. A participant is 100% vested in employer contributions after one year of credited service; if a participant terminates from the Company prior to vesting, employer contributions are forfeited to the Plan.

Notes Receivable from Participants — Participants may borrow from their fund accounts up to a maximum of $50,000 minus the largest outstanding balance during the previous 12 months or 50% of their account balance, whichever is less. The loans are secured by the balance in the participant's account and bear interest at the prime rate as published in the Wall Street Journal on the last day of the month plus 1%. Loans can be repaid over a period of one to five years, or up to fifteen years for the purchase of a primary residence. Principal and interest is paid ratably through payroll deductions or can be paid directly to the Trustee.

Payment of Benefits — The vested portion of a participant's account is payable upon termination of employment, retirement, or death. Retirees and former employees may choose to leave all or part of the vested balance in the Plan until age 70-1/2. After age 70-1/2, if a participant is not actively employed, the account must begin required minimum distributions no later than April 1 of the calendar year following the year the participant turns 70-1/2. Roth contributions do not require a minimum distribution. Certain disabled participants may withdraw Company contributions prior to age 59-1/2.

Forfeited Accounts — As of December 31, 2016 and 2015, forfeited non-vested accounts totaled $83,482 and $104,372, respectively. These accounts will be used to reduce future employer contributions or pay future Plan expenses.

NOTE B – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting — The accompanying financial statements have been prepared under the accrual basis of accounting in accordance with accounting principles generally accepted in the United States of America (GAAP).

Use of Estimates — The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, and changes therein as well as disclosures of contingent assets and liabilities. Actual results could differ from those estimates.

Risks and Uncertainties — The Plan utilizes various investment instruments, including common stock, mutual funds and investment contracts. Investment securities, in general, are exposed to various risks, such as interest rate, credit, and overall market volatility. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the values of investment securities will occur in the near term and such changes could materially affect the amounts reported in the financial statements.

NOTE B – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES, Continued

Investment Valuation and Income Recognition — The Plan's investments are stated at fair value. Fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

- Common stock is valued at the closing price reported on the active market on which the individual securities are traded on the last business day of the Plan year. Shares of registered investment companies are valued at quoted market prices that represent the net asset value of shares held by the Plan at year-end.

- Short term investment funds (STIF's) are stated at amortized cost, which approximates fair value.

- Investments in common collective trust funds (CCT) are valued based upon the redemption price of the units held by the Plan, which is likely to be fair value which is represented by the net asset value as a practical expedient. Unit values are determined by the financial institution sponsoring such CCT by dividing the funds' net assets at fair value by its units outstanding at the valuation dates.

- The SVF is stated at contract value which is comprised of principal and accrued interest. The fund invests principally in guaranteed investment contracts issued by insurance companies; investment contracts issued by banks; synthetic investment contracts (SICs) issued by banks, insurance companies or other issuers, and other securities supporting such SICs; and other similar instruments, which are intended to maintain a constant net asset value.

Participants may ordinarily direct the withdrawal or transfer of all or a portion of their investment in the SVF at contract value. Contract value represents contributions made to the fund, plus credited earnings, less participant withdrawals.

Purchases and sales of securities are recorded on a trade-date basis. Interest income is recorded on the accrual basis. Dividends are recorded on the ex-dividend date. Net appreciation includes the Plan's gains and losses on investments bought and sold as well as held during the year.

Management fees and operating expenses charged to the Plan for investments in the mutual funds are deducted from income earned on a daily basis and are not separately reflected. Consequently, management fees and operating expenses are reflected as a reduction of investment return for such investments.

Payment of Benefits — Benefit payments to participants are recorded upon distribution. There were no amounts allocated to accounts of persons who had elected to withdraw from the Plan but had not yet been paid at December 31, 2016 and 2015.

Excess Contributions Payable — The Plan is required to return contributions received during the Plan year in excess of the IRC limits. There were no Plan contributions in excess of the IRC limits for both December 31, 2016 and 2015.

Administrative Expenses — Certain expenses of maintaining the Plan are paid by the Plan, unless the Plan Sponsor elects to pay the expenses directly. Fees related to the administration of notes receivable from participants are charged directly to the participant's accounts and are included in administrative expenses.

NOTE C – INFORMATION CERTIFIED BY THE TRUSTEES

The Plan administrator elected the method of annual reporting compliance permitted by 29 CFR 2520.103-8 of the Department of Labor's Rules and Regulations for Reporting and Disclosure under ERISA. Under this provision of ERISA, investment information and related activity certified as accurate and complete by a qualified institution need not be subjected to independent audit. The Plan administrator has obtained a certification from Voya Institutional Trust Company as of and for the year ended December 31, 2016 and as of and for the six months ended December 31, 2015 and The Northern Trust Company for the six months ended June 30, 2015, as trustees of the Plan, that the following information included in the Plan's financial statements and supplemental schedule is complete and accurate:

- Investments and notes receivable from participants as of December 31, 2016 and 2015

- Plan transactions related to investment income, securities transactions and interest income on notes receivable from participants for the years ended December 31, 2016 and 2015

- Schedule H, line 4i - schedule of assets (held at end of year) as of December 31, 2016.

Accordingly, at the request of the Plan administrator, the Plan's independent certified public accountants performed no procedures on investment information and related activity, other than to agree the information to the trust statements certified by the Plan's trustee and provided to them by the Plan administrator.

NOTE D – FAIR VALUE OF INVESTMENTS

ASC 820, Fair Value Measurements and Disclosures, provides a framework for measuring fair value. That framework provides a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value, as follows:

Level 1- which refers to securities valued using unadjusted quoted prices from active markets for identical assets.

Level 2- which refers to a valuation based on quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market;

Level 3- which refers to securities valued based on significant unobservable inputs. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Certain investments are valued at the net asset value ("NAV") as provided by the fund administrator. Assets measured at fair value using NAV as a practical expedient are not categorized in the fair value hierarchy

The Plan's policy is to recognize significant transfers between levels at the end of the reporting period. For the years ended December 31, 2016 and 2015, there were no transfers between Levels 1, 2 or 3.

Asset Valuation Techniques — Shares of registered investment companies held are primarily categorized as Level 1.

They are valued at quoted market prices that represent the net asset value of shares held at Plan year-end.

NOTE D – FAIR VALUE OF INVESTMENTS, Continued

Investments in common collective trust funds are valued based upon the redemption price of units held by the Plan, which is likely to be fair value which is represented by the net asset value as a practical expedient. Unit values are determined by the financial institution sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation dates. Funds valued at NAV as a practical expedient are not classified in the fair value hierarchy.

There are no quoted prices in the market for traditional GICs and variable rate GICs, so the aforementioned GIC contract values are carried at the par value. For fixed maturity synthetic GICs, most underlying assets are traded in active markets and have readily quoted market prices. Discounted cash flow valuation models are used to value the GICs at fair value (see Note E). The fair value is represented by the net asset value as a practical expedient. Since these funds are valued at NAV as a practical expedient they are not classified in the fair value hierarchy.

The Plan is invested in short term investment funds (STIF's) that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, short term treasury bills, federal agency securities, certificates of deposit, and commercial paper. STIF's held in the Plan are valued at NAV as a practical expedient and are not classified in the fair value hierarchy.

The following tables set forth by level within the fair value hierarchy a summary of the Plan's investments measured at fair value on a recurring basis at December 31, 2016 and 2015:

	Active Markets For Identical Assets (Level 1)	Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Other (1)	2015 Total
Mutual Funds	$ 548,047,761	$ -	$ -	$ -	$ 548,047,761
Self-directed Brokerage Account	27,601,531	-	-	-	27,601,531
Investments at NAV	-	-	-	15,159,791	15,159,791
	$ 575,649,292	$ -	$ -	$ 15,159,791	$ 590,809,083

	Active Markets For Identical Assets (Level 1)	Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Other (1)	2015 Total
Mutual Funds	$ 502,787,581	$ -	$ -	$ -	$ 502,787,581
Self-directed Brokerage Account	25,828,772	-	-	-	25,828,772
Investments at NAV	-	-	-	13,644,287	13,644,287
	$ 528,616,353	$ -	$ -	$ 13,644,287	$ 542,260,640

NOTE D – FAIR VALUE OF INVESTMENTS, Continued

(1) Certain investments at December 31, 2016 and 2015 were valued at the net asset value ("NAV") as provided by the fund administrator. The following provides additional information regarding their investment strategy and redemption restrictions, if any.

STIF's are managed by State Street Bank and seek the preservation of capital and liquidity and, consistent with these, the highest possible current income. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value as a practical expedient. Redemption is permitted daily without written notice.

Collective trust funds include debt securities managed by Prudential Investment Management. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value as a practical expedient. The objective of the Fund is to outperform the Barclays U.S. Aggregate Bond Index over a full market cycle. The fund strategy is to invest primarily in fixed income securities in the U.S. investment grade sectors, as well as U.S. fixed income securities below investment grade, the debt of developed international markets and the debt of emerging markets. Prudential Investment Management funds require 10 days written notice, which may be waived by the investment manager.

NOTE E – STABLE VALUE FUND

The SVF is managed by Invesco Investment Services with the objective of preserving capital, maintaining liquidity and, consistent with these, the highest possible current income. It is not included in the Fair Value Hierarchy because it is valued at contract value. The SVF invests in a diversified portfolio of GICs issued by major insurance companies and other high-quality investment funds that are wrapped. The fund is considered a fully benefit-responsive investment contract which means participant directed redemptions may be made as frequently as daily at book value. Trustee-directed redemptions may be subject to other specifics, depending, for example, on the market value of the portfolio at the time of redemption request. Stable value funds require 30 days written notice, subject to market value at the time of the redemption request. SVF contract values were $120,115,623 in 2016 and $122,932,719 in 2015.

At December 31, 2016 and 2015, the SVF's investments included a synthetic GIC, which simulates the performance of a GIC through an issuer's guarantee of a specific interest rate (the wrapper contract), and a portfolio of financial instruments that are owned by the Plan. The synthetic GIC contract includes underlying assets, which are held in a trust owned by the Plan and utilize a benefit-responsive wrapper contract issued by the financial institutions listed below. The contract provides that participants execute Plan transactions at contract value. Contract value represents contributions made to the SVF, plus earnings, less participant withdrawals. The interest rates are reset quarterly based on market rates of other similar investments, the current yield of the underlying investments and the spread between the market value and contract value, but the rate cannot be less than 0%. Certain events such as Plan termination or a Plan merger initiated by the Company may limit the ability of the Plan to transact at contract value or may allow for the termination of the wrapper contract at less than contract value. The Plan does not believe that any events that may limit the ability of the Plan to transact at contract value are probable.

NOTE E – STABLE VALUE FUND, Continued

The contract values as of December 31, 2016 and 2015 are as follows:

	2016	2015
Synthetic guaranteed investment contracts:		
Monumental Life Wrap Contracts	$ 28,498,586	$ 29,151,658
ING Wrap Contracts	28,826,263	29,266,967
Prudential	30,605,981	28,993,700
RGA Contract	28,622,138	29,430,881

The SVF also includes investments in the Short Term Investment Fund at State Street Bank of $3,562,655 and $6,089,746 at December 31, 2016 and 2015, respectively.

NOTE F – PLAN TERMINATION

Although it has not expressed any intention to do so, the Company has the right under the Plan to discontinue its contributions at any time and to terminate the Plan subject to the provisions set forth in ERISA. In the event that the Plan is terminated, participants would become 100% vested in their accounts.

NOTE G – FEDERAL INCOME TAX STATUS

The Internal Revenue Service (IRS) has determined and informed the Company by a letter dated September 8, 2017, that the Plan and related trust were designed in accordance with the applicable regulations of the IRC. The Company and Plan management believe that the Plan is currently designed and operated in compliance with the applicable requirements of the IRC, and the Plan and related trust continue to be tax-exempt. Therefore, no provision for income taxes has been included in the Plan's financial statements.

GAAP requires Plan management to evaluate tax positions taken by the Plan and recognize a tax liability (or asset) if the Plan has taken an uncertain position that more likely than not would not be sustained upon examination by the Internal Revenue Service. The Plan administrator has analyzed the tax positions taken by the Plan, and has concluded that as of December 31, 2016 and 2015, there are no uncertain positions taken or expected to be taken that would require recognition of a liability (or asset) or disclosure in the financial statements. The Plan is subject to routine audits by taxing jurisdictions; however, there are currently no audits for any tax periods in progress.

Portland General Electric Company 401(k) Plan

NOTES TO FINANCIAL STATEMENTS - CONTINUED

December 31, 2016 and 2015

NOTE H – RECONCILIATION OF FINANCIAL STATEMENTS TO FORM 5500

As of December 31, 2016 and 2015, the following is a reconciliation of net assets available for benefits per the financial statements to the Form 5500:

	2016	2015
Net assets available for benefits per the financial statements	$ 722,962,048	$ 676,649,145
Notes receivable from participants	(60,330)	(39,544)
Net assets available for benefits per the Form 5500	$ 722,901,718	$ 676,609,601

The Plan had $60,330 and $39,544 of deemed loan distributions at December 31, 2016 and 2015, respectively. These amounts are included as notes receivable from participants in the accompanying statement of net assets available for benefits.

For the years ended December 31, 2016 and 2015, the following is a reconciliation of the change in net assets available for benefits per the financial statements to the Form 5500:

	2016	2015
Change in net assets available for benefits per the financial statements	$ 46,312,903	$ (7,966,773)
Prior year adjustment to contract value for fully Responsive investment contract	-	(2,404,621)
Change in deemed distributions	(20,786)	122,716
Net income (loss) per Form 5500	$ 46,292,117	$ (10,248,678)

NOTE I – EXEMPT PARTY-IN-INTEREST TRANSACTIONS

Certain Plan investments are shares in short term investment money market funds managed by the Trustee. The Northern Trust Company was the trustee as defined by the Plan as of and for the six months ended June 30, 2015 and these transactions qualify as exempt party-in-interest transactions. Fees paid by the Plan to The Northern Trust Company for the investment management services were $90,311 for the six months ended June 30, 2015. Voya Institutional Trust Company (VITC) the trustee as defined by the Plan for the six months ended December 31, 2015 and these transactions qualify as exempt party-in-interest transactions. Fees paid by the Plan to VITC for investment management services were $205,421 for the year ended December 31, 2016 and $180,235 for the six months ended December 31, 2015.

NOTE J – SUBSEQUENT EVENTS

Through October 6, 2017, which is the date the financial statements were available to be issued, there were no other identified events that require consideration for adjustments to, or disclosure in the financial statements.

SUPPLEMENTAL SCHEDULE

Portland General Electric Company 401(k) Plan
EIN: 93-0256820

December 31, 2016

Form 5500, Schedule H, Part IV, Line 4i; Schedule of Assets (Held at End of Year)

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment, Including Maturity Date, Interest Rate, Collateral, and Par or Maturity Value	(d) Cost *	(e) Current Value
	DFA Emerging Markets	Registered investment company	$ -	$ 3,471,349
	Diversified Bond Funds	Registered investment company	-	30,627,693
	International Equity Fund	Registered investment company	-	24,846,836
	Large Cap Equity	Registered investment company	-	77,539,370
	SM CAP Equity Fund	Registered investment company	-	46,274,317
	T.ROWE 2010	Registered investment company	-	19,388,988
	T.ROWE 2020	Registered investment company	-	57,254,194
	T.ROWE 2030	Registered investment company	-	32,701,334
	T.ROWE 2040	Registered investment company	-	29,605,327
	T.ROWE 2050	Registered investment company	-	12,934,515
	T.ROWE 2060	Registered investment company	-	705,317
	Vanguard Extended Market Index Fund	Registered investment company	-	41,973,305
	Vanguard Institutional Index Fund	Registered investment company	-	94,164,560
	Vanguard Total Bond Market Index	Registered investment company	-	47,029,650
	Vanguard Total International Stock Index Fund	Registered investment company	-	43,113,905
	JP Morgan Diversified Real Return Fund	Registered investment company	-	1,576,892
	SELF-DIRECTED BROKERAGE ACCOUNT	Common stock, mutual funds, fixed income securities, money market funds	-	27,601,531
	PARTICIPANT LOANS	Miscellaneous assets - with interest rates ranging from 4.25%-9.25%, maturing at various dates through 2030.	-	9,985,455
	STABLE VALUE FUND	Stable value fund	-	120,115,623
	TOTAL		$ -	$ 720,910,161

* Cost information is not required for participant-directed investments and therefore is not included.

Portland General Electric Company 401(k) Plan
EIN: 93-0256820

December 31, 2016

Form 5500, Schedule H, Part IV, Line 4i; Schedule of Assets (Held at End of Year)

(a)	(b) Identity of Issue, Borrower, Lessor or Similar Party	(c) Description of Investment, Including Maturity Date, Interest Rate, Collateral, and Par or Maturity Value	(d) Cost *	(e) Current Value
	DFA Emerging Markets	Registered investment company	$ -	$ 3,471,349
	Diversified Bond Funds	Registered investment company	-	30,627,693
	International Equity Fund	Registered investment company	-	24,846,836
	Large Cap Equity	Registered investment company	-	77,539,370
	SM CAP Equity Fund	Registered investment company	-	46,274,317
	T.ROWE 2010	Registered investment company	-	19,388,988
	T.ROWE 2020	Registered investment company	-	57,254,194
	T.ROWE 2030	Registered investment company	-	32,701,334
	T.ROWE 2040	Registered investment company	-	29,605,327
	T.ROWE 2050	Registered investment company	-	12,934,515
	T.ROWE 2060	Registered investment company	-	705,317
	Vanguard Extended Market Index Fund	Registered investment company	-	41,973,305
	Vanguard Institutional Index Fund	Registered investment company	-	94,164,560
	Vanguard Total Bond Market Index	Registered investment company	-	47,029,650
	Vanguard Total International Stock Index Fund	Registered investment company	-	43,113,905
	JP Morgan Diversified Real Return Fund	Registered investment company	-	1,576,892
	SELF-DIRECTED BROKERAGE ACCOUNT	Common stock, mutual funds, fixed income securities, money market funds	-	27,601,531
	PARTICIPANT LOANS	Miscellaneous assets - with interest rates ranging from 4.25%-9.25%, maturing at various dates through 2030.	-	9,985,455
	STABLE VALUE FUND	Stable value fund	-	120,115,623
	TOTAL		$ -	$ 720,910,161

* Cost information is not required for participant-directed investments and therefore is not included.

April 23, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 224
Dated April 6, 2018

Request:

Regarding Accounting Standards Update (ASU) No. 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (Mersereau – Neitzke 400/34),

a. **Please explain how the following footnote disclosure found in the 2017 SEC Form 10k, page 80, is consistent with the settlement in Commission Order 17-511:**
   i. **"The Company does not plan to early adopt. For ratemaking purposes, the Company will continue to be allowed to recover this portion of the non-service costs as a component of rate base, however such amounts will be recorded as Regulatory assets on the Company's condensed consolidated balance sheets, instead of Utility plant, and amortized in a systematic and rational manner and reflected as expense in a line item outside the subtotal of income from operations on the condensed consolidated statements of income and other comprehensive income. PGE estimates the portion of the non-service components of net periodic pension and postretirement benefit costs that is eligible for deferral for ratemaking purposes, to be $3 million for the twelve month period ending December 31, 2018"**
b. **Please identify any related deferral application or request for an accounting order either granted, pending, or to be filed before the Commission.**
c. **Please discuss how the $3m amount is reflected in the current rate case.**
d. **Please explain why the company would propose to establish a regulatory asset and amortization method rather than simply electing "to continue capitalizing all of the pension and PBOP costs, as companies have done so prior to the issuance of the ASU" as allowed under FERC Docket No. AI18-1-000 Accounting and Financial Reporting for Pensions and Post-retirement Benefits other than Pensions.**

Response:

a. Consistent with Commission Order No. 17-511, PGE has continued to capitalize a portion of all components of pension and Other Post-Employment Benefits (OPEB) expense to Net Utility Plant, in-line with historical treatment. This is reflected in PGE's Federal Energy Regulatory Commission (FERC) accounting and reporting used for setting customer prices. However, it is important to note that for Securities and Exchange Commission (SEC) financial reporting purposes, PGE was mandated to conform with the Financial Accounting Standards Board (FASB) new standard, ASU 2017-07. This means that while PGE is allowed recovery of such amounts under Commission Order 17-511, PGE is not allowed to present such amounts in Net Utility Plant, but instead reclassifies such amounts to a Regulatory Asset, for SEC reporting purposes. As a result, PGE has developed a dual recordkeeping system so that it can account for pension overhead costs consistent with FERC and Commission Order 17-511, as well as, meet the presentation requirements for SEC reporting. Attachment 224-A provides an accounting whitepaper developed by PricewaterhouseCoopers discussing the impact of ASU 2017-07.

b. There is no deferral application or request for accounting order. The Regulatory Asset is for SEC reporting purposes only as discussed in part (a) above.

c. The $3 million is reflected as a component of Net Utility Plant, consistent with Commission Order 17-511 and FERC reporting.

d. As discussed in part (a) above, for SEC reporting purposes, PGE is mandated to reclassify such amounts from Net Utility Plant to a Regulatory Asset. However, for FERC reporting and ratemaking purposes, we have continued to capitalize such amounts as a component of Net Utility Plant. PGE has developed a system of dual recordkeeping to track the two methods.

UE 335

Attachment 224-A

Provided in Electronic Format

Changes to accounting for net periodic pension and postretirement costs - PwC Whitepaper

In depth
A look at current financial reporting issues

pwc

Changes to accounting for net periodic pension and postretirement costs
Considerations for Energy & Utility companies

No. US2017-23
September 26, 2017

What's inside:

At a glance

In March 2017, the FASB issued final guidance on the presentation of net periodic pension and postretirement benefit cost (net benefit cost)[1]. While intended to improve how such costs are reflected in the financial statements, the new guidance has implications to Energy & Utilities companies beyond just the change in presentation.

The new guidance is effective in 2018 for public business entities. Other entities have an additional year.

Background

Net benefit cost comprises several components that reflect different aspects of an employer's financial arrangements, as well as the cost of benefits provided to employees. Under current US GAAP, those components must be aggregated and presented as a single net employee compensation cost in the financial statements. ASC 715, *Compensation—Retirement Benefits*, does not prescribe where the amount of net benefit cost should be presented in an employer's income statement and does not require entities to disclose the amount of net benefit cost presented in the income statement or capitalized in assets by line item.

Stakeholders provided feedback to the FASB that the presentation of defined benefit cost on a net basis combines elements that are distinctly different in their predictive value. As such, these stakeholders believe that the current presentation requirements have less value and require users to incur greater costs to analyze financial statements. In response to these concerns, the FASB issued the new guidance, which changes the presentation of net benefit cost in the income statement and limits the components eligible for capitalization.

Key provisions

Under the new guidance, an employer is required to report the service cost component of net benefit cost in the same line item as other compensation costs arising from services rendered by the relevant employees during the period. The other components of net benefit cost (e.g., interest cost, expected return on plan assets, amortization of prior service costs, amortization of actuarial gains/losses), as defined in ASC 715-30-35-4, will be presented in the income statement separate from the service cost component and outside of the subtotal of income from operations, if one is presented.

---

[1] Accounting Standards Update 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Cost*

Only the service cost component will be eligible for capitalization (for example, as a cost of a self-constructed asset).

Why is this important to Energy & Utility companies?

The new requirements for the presentation of net periodic pension and postretirement benefit costs will potentially have a significant impact on Energy & Utility companies that maintain pension and/or postretirement plans.

FERC/State vs. US GAAP differences

Only service cost will be eligible for inclusion in overhead pools for purposes of capitalization under US GAAP. The FERC has recently indicated that it will allow entities to change their capitalization policy for regulatory accounting and reporting purposes to be consistent with the new US GAAP requirements. This change will be allowed as a one-time policy election upon adoption of the guidance.

Companies that wish to make this election will not be required to obtain approval from the FERC Accounting or Rate Staff provided two conditions are met: (1) the change is a one-time election that is only made upon adoption of the guidance, and (2) changes to the capitalization policy must be disclosed in the entity's Form No. 1 or 2 and in any formula rate filings with the FERC.

Alternatively, entities may elect to continue to capitalize all components of net benefit cost for regulatory purposes, which would give rise to an additional FERC vs. US GAAP reporting difference.

PwC observation:

The election allowed by the FERC may not be allowed by individual State Regulators due to the possible negative rate consequences in the near-term, potentially creating a different accounting treatment at the state vs. FERC reporting levels. In deciding whether to make the FERC election, companies should consider the implications of a State Regulator that does not allow for the FERC policy election.

Entities will need to consider the structure of their organization and their benefit plans (i.e., which entity is the plan sponsor) in order to assess the impact of the new guidance and to verify if they are eligible to make the election. Refer to the "Stand alone vs. consolidated reporting considerations" section below for further discussion of benefit plan structures.

Accounting entries – Examples

The accounting applied by a rate-regulated entity will depend on whether the total net benefit cost is greater or less than the service cost component. Below is a simplified list of potential journal entries for each scenario.

Example 1 - Service cost is less than net benefit cost

Assume:

- The full amount of net benefit cost is capitalized.
- The entity does not elect to change its capitalization policy for FERC reporting.
- The regulated utility is the sponsor of the plan.
- Service cost is $1,000.
- Net benefit cost is $1,500.

For FERC / State reporting:

Entry #1		
Dr. Net benefit cost	$1,500	
Cr. Benefit obligation		$1,500
Entry #2		
Dr. Plant	$1,500	
Cr. Net benefit cost		$1,500

For US GAAP reporting:

Entry #1		
Dr. Net benefit cost	$1,000	
Dr. Other cost*	500	
Cr. Benefit obligation		$1,500
Entry #2		
Dr. Plant	$1,000	
Cr. Net benefit cost		$1,000
Entry #3		
Dr. Regulatory asset*	$500	
Cr. Other cost*		$500

* Other cost would be presented below the sub-total for operating income, if presented. Regulatory assets would be amortized to the same line item.

Example 2 - Service cost is less than net benefit cost

Assume:

- Only 50% of net benefit cost is capitalized.
- The entity does not elect to change its capitalization policy for FERC reporting.
- The regulated utility is the sponsor of the plan.
- Service cost is $1,000.
- Net benefit cost is $1,500.

For FERC / State reporting:

Entry #1		
Dr. Net benefit cost	$1,500	
Cr. Benefit obligation		$1,500
Entry #2		
Dr. Plant	$750	
Cr. Net benefit cost		$750

For US GAAP reporting:

Entry #1		
Dr. Net benefit cost	$1,000	
Dr. Other cost*	$500	
Cr. Benefit obligation		$1,500
Entry #2		
Dr. Plant	$500	
Cr. Net benefit cost		$500
Entry #3		
Dr. Regulatory asset*	$250	
Cr. Other cost*		$250

* Other cost would be presented below the sub-total for operating income, if presented. Regulatory assets would be amortized to the same line item.

As is shown in the above examples, assuming the costs are probable of recovery from ratepayers, the incremental cost capitalized for regulatory reporting purposes in excess of service cost is recognized as a regulatory asset. The recovery period for the regulatory asset will likely be the average life of the plant assets (assuming no changes in recovery of depreciation expense). In addition, although the above examples are presented on a pre-tax basis, deferred tax balances will be impacted for the balance sheet differences shown above. Consequently, in future periods, both depreciation and regulatory asset amortization amounts will be impacted by the new guidance.

Pursuant to the requirements of an entity's regulator, costs of financing construction (including both debt and equity components) may be capitalized through AFUDC as part of the acquisition cost of the plant and equipment in accordance with ASC 980-360-25-1 if inclusion of these costs into future customer rates is probable. The new guidance does not change the current accounting for AFUDC.

When service cost is greater than net benefit cost, there are two approaches that can be used to record the changes under the new guidance for US GAAP reporting purposes.

As shown in Example 3, in Option A, one method is to record the non-service cost "gains" as a regulatory liability, assuming it is probable that these gains will ultimately be returned to ratepayers through future reductions in rates, similar to the accounting for refunds of gains in accordance with ASC 980-405-25-1(c).

Alternatively, under Option B, plant is effectively reduced to the allowable FERC/State levels via analogy to "disallowance of recently completed plant" accounting under ASC 980-360-35-12. Under this methodology, the net amount capitalized in plant under FERC and US GAAP is equal.

Example 3 - Service cost is greater than net benefit cost

Assume:

- The full amount of net benefit cost is capitalized.
- The entity does not elect to change its capitalization policy for FERC reporting.
- The regulated utility is the sponsor of the plan.
- Service cost is $2,000.
- Net benefit cost is $1,500.

For FERC / State reporting:

Entry #1		
Dr. Net benefit cost	$1,500	
Cr. Benefit obligation		$1,500
Entry #2		
Dr. Plant	$1,500	
Cr. Net benefit cost		$1,500

Option A: For US GAAP reporting:

Entry #1		
Dr. Net benefit cost	$2,000	
Cr. Other income*		$500
Cr. Benefit obligation		1,500
Entry #2		
Dr. Plant	$2,000	
Cr. Net benefit cost		$2,000

Entry #3		
Dr. Other income*	$500	
Cr. Regulatory liability		$500

Option B: For US GAAP reporting:

Entry #1		
Dr. Net benefit cost	$2,000	
Cr. Other income*		$500
Cr. Benefit obligation		1,500
Entry #2		
Dr. Plant	$2,000	
Cr. Net benefit cost		$2,000
Entry #3		
Dr. Net benefit cost	$500	
Cr. Plant		$500

* Other cost/income would be presented below the sub-total for operating income, if presented.

Under either option, the expense recognition will also be impacted as a result of any pension or postretirement cost trackers that a utility may have as part of its cost recovery structure.

In addition, the new guidance creates a mismatch between what is included in operating revenue (rates charged to customers will reflect recovery of the total net benefit cost) as compared to what is included in operating expenses (service cost only).

Systems, process, and control considerations

Amounts reported under the FERC/State and US GAAP may differ as a result of the new guidance. Over time, these differences will likely grow and the associated asset values will diverge. A key question companies will need to consider is whether such financial statement adjustments can be maintained off-line and recorded as “top side” adjustments (outside the general ledger), or if a more permanent systems solution is warranted. The cost of a system modification will likely be a key consideration. Regardless, processes and controls will need to be updated to ensure the accuracy and completeness of the information reported under either framework.

Companies need to move quickly to assess the potential impact on the systems, processes and controls given that the new guidance will be effective in 2018 for public business entities.

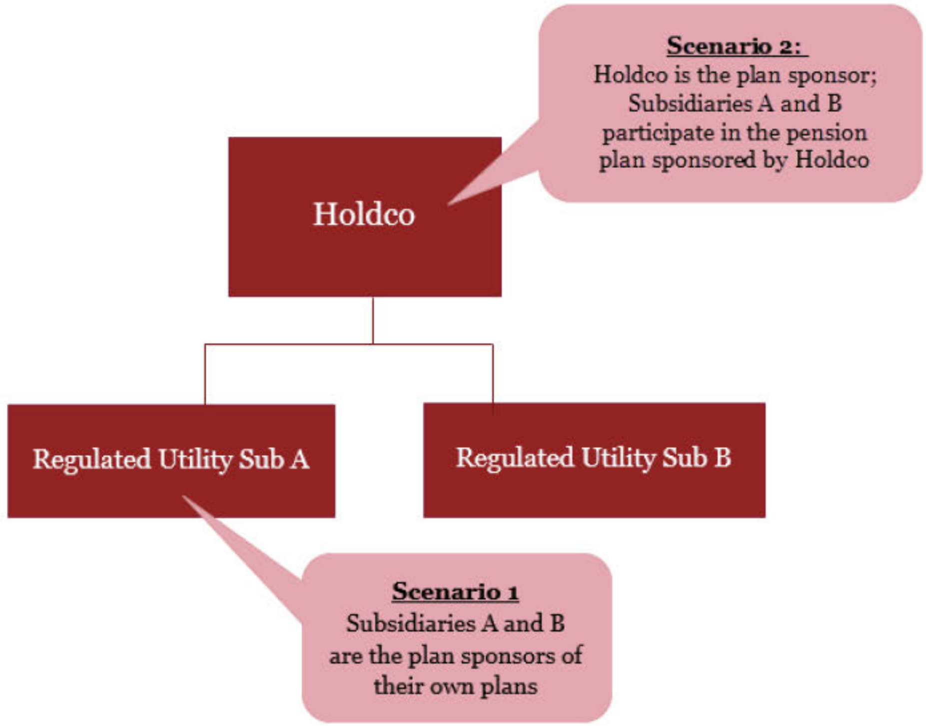
Tax considerations

Certain companies follow their book overhead capitalization methodology for tax purposes. So the impact of the changes in overhead capitalization will need to be reflected in the tax basis as well. In addition, we believe the income statement classification of taxes related to pension and postretirement costs should follow the book presentation (i.e., presentation “above and below the line” should be consistent for book and tax).

Stand-alone vs. consolidated reporting considerations

The impact of adopting the new guidance will largely depend on the structure of the reporting entity and the nature of its benefit plan. If the reporting entity participates in its parent’s plan, the impact in its stand-alone financial statements will differ depending on whether the plan is accounted for as a multi-employer or multiple-employer plan under ASC 715.

An entity should first identify the sponsor of the benefit plan. The parent company (Holdco) may sponsor plans on behalf of all subsidiaries. Alternatively, individual subsidiary entities may be the plan sponsors of their own plans.



In scenario 1, the subsidiary is the plan sponsor. As a result, the benefit plan would be subject to the accounting guidance in ASC 715, and the impact of the new guidance would be reflected in both the stand-alone reporting of the subsidiary and in the reporting for the consolidated entity.

In scenario 2, the parent is the plan sponsor. The impact of the guidance will depend on whether the benefit plan is accounted for as a multi-employer or multiple-employer plan. The following table summarizes the key characteristics of multi-employer and multiple-employer plans as outlined in ASC 715-80 and 715-30, respectively.

Multi-employer vs. Multiple-employer accounting

Multi-employer (ASC 715-80)	Multiple-employer (ASC 715-30)
Two or more unrelated employers contribute OR A parent and subsidiary contribute (if the subsidiary issues separate financial statements)	Aggregation of single-employer plans The main purpose is to reduce the cost of plan administration by pooling together the plans of multiple employers
Assets are commingled and can be used to provide benefits to employees of other participating employers	Assets are not commingled
Participating employers do not select different benefit formulas	Participating employers can select different benefit formulas
Employer accounts for the plan as if it were a defined contribution plan and	Each employer accounts for its respective interest in the pooled plan and records

Multi-employer (ASC 715-80)	Multiple-employer (ASC 715-30)
contributions are recorded as net benefit cost	pension costs in accordance with ASC 715-30 (e.g., defined benefit plan)
Any required contributions that are due and unpaid, as well as any probable withdrawal obligations are recognized as a liability	
No separate accounting for assets contributed by the participating employers	

In the stand-alone financial statements of a subsidiary, participation in a commingled parent-sponsored plan is accounted for in the same manner as if it was a multi-employer plan. For multi-employer plans, the new guidance will only be reflected in the financial statements of the consolidated entity.

PwC observation:

Under a multi-employer plan, the regulated subsidiary will often make contributions to the parent in accordance with a legal agreement. These contributions determine the benefit cost recorded by the subsidiary. While the parent will be limited to capitalizing only the service component of net benefit cost under the new guidance, the total amount paid by the subsidiary will be reflected as compensation cost and thus, eligible for capitalization. As a result, higher costs could be capitalized at the subsidiary compared to the parent.

When the parent is the plan sponsor and the benefit plan is accounted for as a multiple-employer plan under ASC 715-30, the impact of the new guidance will be reflected in the financial statements of both the subsidiary and the parent. In multiple-employer plans, multiple single-employer plans are aggregated together to reduce the costs of administering the plans, and the assets are not commingled. Each employer accounts for its respective interest in the assets and records its share of pension costs in accordance with the guidance in ASC 715-30, as if it had its own defined benefit plan.

As a result, for multiple-employer plans, the new guidance will impact the presentation of benefit costs (i.e., the separate presentation of service and other costs) in both the regulated subsidiary and the consolidated financial statements.

What's next

The guidance is effective for public business entities for annual reporting periods beginning after December 15, 2017, and interim periods within those reporting periods. For other entities, the guidance is effective for annual periods beginning after December 15, 2018, and interim periods within annual periods beginning after December 15, 2019. Early adoption is permitted as of the beginning of an annual period for which financial statements have not been issued or made available for issuance. However, early adoption is only allowed in the first interim period presented in a fiscal year; therefore, early adoption was only permitted in the first quarter of 2017 for calendar year-end public companies.

The new guidance is required to be applied on a retrospective basis for the presentation of the service cost component and the other components of net benefit cost (including gains and losses on curtailments and settlements, and termination benefits paid through retirement plans), and on a prospective basis for the capitalization of only the service cost component of net benefit cost. Amounts capitalized prior to the date of adoption should not be adjusted through a cumulative effect adjustment, but should continue to be recognized in the normal course as plant assets are depreciated.

There is a practical expedient for the retrospective application that permits the use of the amounts disclosed for the various components of net benefit cost in the pension and other postretirement benefit plans footnote as the basis for the retrospective application. This would be in lieu of determining how much of the various components of the net benefit cost were actually reflected in the income statement each period as a result of the capitalization of certain costs and their subsequent amortization. Entities should disclose if they elect to use the practical expedient.

Impacted companies should consider taking the following actions:

- Assess benefit plan structures (to determine if a company is eligible for aligning FERC and US GAAP accounting policies).
- Evaluate the impact to rate-payers and the company's financial statements.
- If a policy alignment is warranted, consider the need to discuss the policy change with the State Regulator.
- Consider system, process and control implications. Additional changes may be necessary if policy alignment is not expected.
- Consider outreach to stakeholders within the organization (e.g., Investor Relations, Budget & Planning, Tax) to ensure awareness of the impact of the new guidance.

To have a deeper discussion, contact:

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Follow @CFOdirect on Twitter.

May 2, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 231
Dated April 18, 2018

Request:

Please provide a detailed explanation of how insurance costs are allocated to non-utility operations, and provide a work paper showing how the allocation is calculated.

Response:

As stated in PGE Exhibit 200, Section IX:

- Administrative and general (A&G) costs are allocated based on labor dollars to the respective operating areas.
- The labor allocation does not include non-utility or "below-the-line" costs because these costs already receive allocations for corporate governance (i.e., A&G/Support costs) and service providers (i.e., Facilities, Information Technology, and Print/Mail Services). More specifically, PGE's Facility allocation applies the appropriate share of property insurance to non-utility accounts based on the occupancy shares of the World Trade Center (as also described in PGE's Cost Allocation Manual provided annually with PGE's Affiliated Interest Report).

Attachment 231-A provides the calculation of amounts allocated to non-utility. The "Calculation of PGE Percent" tab shows the derivation of the PGE (utility) vs non-PGE (non-utility) portion of the World Trade Center and the "Summary" tab shows the insurance expense (row 19) as part of the final Facilities allocation.

Attachment 231-A is protected information subject to Protective Order No. 18-047.

UE 335

Attachment 231-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Facilities Allocation

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 244
Dated April 19, 2018

Request:

Please provide an analysis showing the 2017 actual project spend ($1.8m) by project (Lobdell-Batzler 500/10 footnote 6).

Response:

Attachment 244-A provides the requested information.

UE 335

Attachment 244-A

Provided in Electronic Format Only

R& D Actuals (2017)

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 245
Dated April 19, 2018

Request:

Please provide the final approved budget for 2017 R&D Projects (as per UE 319 OPUC DR Attachment 224-A which is footnoted as “subject to change”).

Response:

See PGE’s response to OPUC Data Request No. 244, Attachment 244-A.

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 246
Dated April 19, 2018

Request:

Please provide R&D Project Completion Estimates for 2017 and beyond (same format as UE 319 OPUC DR Attachment 224-A).

Response:

Attachment 246-A provides the requested information.

UE 335

Attachment 246-A

Provided in Electronic Format

R&D Project Completion Estimates for 2017

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 247
Dated April 19, 2018

Request:

Regarding the 2018 list (UE 319 Lobdell-Tooman Exhibit 604),

a. **Please identify the projects that carryover to the 2019 list and provide a work paper showing the expected amounts to be spent in 2018 and 2019.**

   i. **Please provide a narrative explanation for projects which were delayed or where the project budget has increased beyond UE 319 amount.**

   ii. **Please provide a list of any replacement projects funded by the R&D steering committee that were not on the UE 319 list for 2018.**

Response:

a. Attachment 247-A provides the list of projects that we expect to carryover from 2018 to 2019 and the amounts for 2018 and forecasted costs for 2019.

   i. There was only one 2018 project delay: the PrepHub project. This delay was due to funding constraints on the part of one of the program partners.

   ii. PGE had one replacement project, the EPRI P64 Boiler and Steam Turbine Cycle project, which involved an expenditure of $33,043.

UE 335

Attachment 247-A

Provided in Electronic Format Only

2018 – 2019 Multi Year Projects

May 1, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 278
Dated April 20, 2018

Request:

Regarding Exhibit 206 and the work paper "Exhibit Support 2019_Tax Plan"

a. **Please provide a narrative explanation (e.g. plant additions, changes in assessed value for existing property, tax rate changes, etc.) of the expected increases in the following accounts,**
   i. **Account 4081001 Property Tax Oregon**
      1. **2017 $53,670,781**
      2. **2018 $55,982,170 (4.3% increase 2017-2018)**
      3. **2019 $62,995,310 (17.4% increase 2017-2019)**
   ii. **Account 4081002 Property Tax Washington**
      1. **2017 $2,118,221**
      2. **2018 $2,370,228 (11.9% increase 2017-2018)**
      3. **2019 $2,549,148 (20.3% increase 2017-2019)**
   iii. **Account 4081003 Property Tax Montana**
      1. **2017 $4,838,828**
      2. **2018 $6,003,000 (24.1% increase 2017-2018)**
      3. **2019 $5,316,372 (9.9% increase 2017-2019)**
   iv. **Account 4081014 Miscellaneous Taxes and Licenses Montana**
      1. **2017 $356,306**
      2. **2018 $458,304 (28.6% increase 2017-2018)**
      3. **2019 $432,504 (21.4% increase 2017-2019)**

b. **Please provide in an Excel worksheet, the following information for the years 2015 through 2017 inclusive and estimated amounts for 2018 and 2019:**

	2019	**2018**	**…**	**2015**
Assessed Oregon Property Value				
Oregon Property Value following appeal				
Oregon Net Book Value of Property				
Oregon property taxes accrued				

Oregon property taxes actually paid				
Actual Tax Rate				
Assessed Montana Property Value				
Montana Property Value following appeal				
Montana Net Book Value of Property				
Montana property taxes accrued				
Montana property taxes actually paid				
Actual Tax Rate				
Assessed Washington Property Value				
Washington Property Value following appeal				
Washington Net Book Value of Property				
Washington property taxes accrued				
Washington property taxes paid				
Actual Tax Rate				

Response:

a.

i. $1.2 million of the increase from 2017 to 2018 is due to an increase in plant assets and $0.8 million of the increase is due to additional CWIP[1] balances that will be assessed property tax expense. Additionally, a full year of the Carty SIP is included in 2018, totaling $1.2 million, versus a half-year payable in 2017. These increases are offset by a $1.0 million decrease in the Oregon property tax rate.

$4.9 million of the increase from 2018 to 2019 is due to an increase in plant assets. In addition, $1.0 million of the increase is due to an increase in the forecasted Oregon property tax rate, and $1.1 million is due to additional CWIP balances that will be assessed property tax expense.

ii. The expected increases are attributed to a higher estimated tax assessment for Tucannon based on historically trended assessed values.

iii. The increase from 2017 to 2018 is attributed to higher estimated tax rates for Colstrip. The increase from 2018 to 2019 is due to a change in the Montana apportionment from operating to power costs increasing the total assessment allocated to beneficial use.

iv. The Montana Electrical Energy Producer's License Tax is based on energy production at Colstrip. The tax is currently at $.0002 per kilowatt hour, and any increases or decreases are based on Colstrip generation. Thus, the $0.1 million increase from 2017 to 2018 is due to an increase in Colstrip generation, and the approximate $0.03 million decrease from 2018 to 2019 is due to a decrease in expected Colstrip generation.

[1] Construction work in progress.

b. Attachment 278-A provides the requested information. Attachment 278-A is protected information and is subject to Protective Order 18-047.

UE 335

Attachment 278-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Property Values – Oregon, Montana, and Washington

May 2, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC *Confidential* Data Request No. 228
Dated April 18, 2018

Request:

Please explain how the "50% of non-primary layers of D&O insurance" (Lobdell-Batzler 500/20) is being reflected in the work paper "2019 Insurance Forecast Detail_CONF".

Response:

See PGE's Response to OPUC Docket No. 214. PGE does not consider this request nor PGE's response to this request confidential.

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 248
Dated April 19, 2018

Request:

Please provide the exact amount of proposed administrative expenses for 2019 (Lobdell-Batzler 500/10 footnote 6).

Response:

PGE included approximately $3.2 million for total R&D costs in its test year forecast. PGE Exhibit 500, page 11, Footnote 6 states, "Approximately $3.0 million is budgeted for 2019 R&D projects and the remainder is for administrative expenses". The remaining amount of $0.2 million is for forecast administrative expenses.

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 249
Dated April 19, 2018

Request:

Regarding the 2019 list (UE 335 Lobdell-Batzler Exhibit 503),

a. **Please resubmit the exhibit with dollar values for each project (as was provided in the prior year).**
b. **For projects where PGE is only providing a portion of the funding (e.g. EPRI projects, university research, etc.), please provide the total project cost and the percentage contributed by PGE.**

Response:

a. See attachment 249-A, a supplement to PGE Exhibit 503.

b. See attachment 249-B.

UE 335

Attachment 249-A

Provided in Electronic Format

PGE Exhibit 503 modified

UE 335

Attachment 249-B

Provided in Electronic Format

2019 Project Funding Report

PGE 2019 R&D Approved Projects
Brief Descriptions

The below R&D projects were brought before PGE's Research and Development Committee for approval on April 26, 2018 and the Committee approved them for funding. PGE expects most of these projects to continue through 2021. Due to the fluid nature of research projects, funding amounts are subject to change.

These projects primarily relate to the below topics:

SG	Smart Grid
SR	System Reliability
RP	Renewable Power
OE	Operational Efficiency
ES	Energy Storage
SY	System Resiliency
S	Safety

This document is a supplement to PGE Exhibit 503

PGE R&D Approved Projects for 2019		
Brief Description	**Topic**	**2019 $$**
1. **EPRI** P1 Power Quality (3-year) This program encompasses three separate modules. PS1A which is improving power quality (PQ) in the transmission and distribution system, PS1B which is integrating PQ monitoring and intelligent applications to maximize system performance, and PS1C which is achieving cost-effective PQ compatibility between the electrical system and future loads. These three modules will help PGE (Portland General Electric) with the increased grid complexity by testing new grid components such as smart inverter, smart meters, photovoltaic (PV), etc. This will also help PGE move PQ from merely reacting to understanding, managing, and preventing tomorrow's PQ issues. The goal would be to maximize the value from PQ data streams to better deploy advanced, low cost PQ techniques to improve the grid reliability. The entirety of the P1 program is to solve real, valuable utility issues through PQ expertise and research. Some examples include advanced diagnostics using PQ data to help anticipate equipment failure, advanced data visualization and validation, and PQ assessments of distributed energy resources (DER) technology. Customer Benefit: The customer would benefit from increased grid reliability by utilizing smarter systems and making optimal use of existing PQ data streams to anticipate equipment failure, predict future PQ reliability issues, and build a smarter grid. By assessing the impacts of DER, PGE can better plan for the future and avoid potential PQ impacts to the customer.	SR	127,000
2. **EPRI** P60 EMF and RF Health Assessment & Safety The Electric Power Research Institute's (EPRI) Program 60 addresses electric and magnetic field (EMF) and radio-frequency (RF) exposures and health issues. Planning and building new transmission and distribution (T&D) projects takes on heightened importance as the power grid is upgraded and modernized by increased asset capacity and integration of smart grid technology and remotely-located renewable energy resources. New T&D construction and capacity upgrades to T&D lines and substations, building electric vehicle (EV) charging infrastructure, and expansion of smart grid technology's reliance on two-way wireless communication, can create public concerns about possible human health risks from EMF and RF exposures. Such concerns can lead to lengthy delays and regulatory decisions affecting project schedules and costs. Program 60 provides PGE with research, analyses, and expertise to better inform public dialogue and regulatory oversight. It is comprised of two project sets, P60A: Community and Residential Studies and P60B: Occupational Studies. These deliver timely, reliable EMF and RF research results, including communication materials, relevant background information, and analyses of key external studies. Program 60 research, combined with EPRI staff expertise, contributes to EMF and RF scientific knowledge, better enabling objective health risk evaluations and exposure guideline development aimed at reducing uncertainties for PGE customers and PGE workers . Customer Benefit: Both EMF and RF have been classified by the International Agency for Research on Cancer as possible human carcinogens. As our infrastructure ages, the grid expands to address electric vehicles, renewable integration, and new technologies (T&D construction, smart meters); we need to understand the latest in EMF research. PGE's support of P60 demonstrates our leadership and proactive approach to addressing potential community and regulatory concerns. Without this participation, PGE would be unable to access experts and the benefits of EMF and RF research geared toward the electric utility industry. Ultimately, the EPRI EMF/RF Program provides research, analyses, and expertise to better inform public dialogue and regulatory oversight on EMF and RF health and safety issues that is	S	145,000

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based on sound science.		
3. **EPRI** Program 62 – Occupational Health and Safety (3-year) The Electric Power Research Institute's (EPRI) Program 62 (P62) provides members with research relevant to current and anticipated occupational health and safety (OH&S) issues. The deliverables derived from PGE's engagement will be used to build, update, and sustain our occupational health and safety program. P62 also provides the ability to guide future Oregon Health& Science University ("OHSU") research for the industry while leveraging the experience, ideas, and funding of other electric utility companies. Deliverables relate directly to the influence of worker protective clothing (heat/cold stress); economic evaluation of ergonomic interventions; economic safety metrics/indicators; development of an exposure database; and SF6 decomposition by-products. Additional deliverables include monthly safety webcasts (recorded), a technical workshop, and access to EPRI's technical staff. By utilizing EPRI, PGE has an information resource that will allow for better short- and long-term safety planning and strategizing. The program is designed to address both current issues and anticipate those of tomorrow. Customer Benefit: Participation in Program 62 will provide PGE with past, current and future research designed to address safety and health issues facing PGE. Implementing these research findings will lead to enhanced customer service and operational efficiency through the development of improved safety practices and procedures.	S	44,000
4. **EPRI** P88 Combined Cycle HRSG and Balance of Plant (3-year) This research will use work performed by EPRI to improve the design and operation of the heat recovery steam generators (HRSGs) at PGE. This work can be utilized by plant operation and maintenance teams and the corporate engineering group for the design of new plants, and the project engineering group when it comes to new upgrades/improvement projects to ensure that the new projects take into account the latest and best practices are included in the new design. The research information included in Program 88 will provide training material for PGE employees, and keep best practices available so that PGE works proactively in identifying issues and addressing them before these issues can become a safety concern or impact plant reliability. Joining Program 88 will also allow PGE to have input on the projects that will be evaluated by EPRI and participating industries that are not electric utilities. This will benefit PGE by having EPRI work on projects that are specific to PGE. PGE can also benefit by utilizing the EPRI team as a resource when it comes to evaluating design of new projects or other evaluations related to program 88. PGE currently owns 3 HRSGs not including Beaver or Coyote 2 unit. Some of the plants are around 10 years old and it will be very important for PGE to stay at the forefront of the new research and apply the latest technology to our HRSGs. This may be even more important as PGE prepares to enter the Energy Imbalance Market (EIM). Customer Benefit: To remain competitive and also meet customer requirements PGE needs to be smart in how it operates its assets. Research developed from Program 88 will allow PGE to be proactive in finding and mitigating potential issues before those issues result in unwanted forced outages. Participation in Program 88 will also support the development of a Covered Piping Program (a code requirement for Carty) to inspect insulated high energy piping systems at set frequencies for high stress and high risk (i.e. near walkways, control room, etc.) areas. PGE plant personnel work around these dangerous systems every day, safety is of utmost concern and proactive	SR	80,000

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inspections can help ensure pipe integrity is maintained.		
5. **EPRI** P161 Information and Communications Technology Diverse areas of research covering Emerging Technologies and Technology Transfer, Information & Communication Technology (ICT) for Transmission, ICT for Distribution, ICT for Distributed Energy Resources (DER), Enterprise Architecture & Systems Integration, Advanced Metering Systems, and Telecommunications. EPRI's goal is to "conduct research/development/demonstrations to promote the reliability, flexibility, resiliency and security of data transport and management to support grid operations." Applicable research areas include ICT/Security Architecture for Distributed Energy Resources, data management, GIS best practices, centralized vs decentralized control, augmented reality, business efficiency, telecommunications management, and persistent WiFi. Customer Benefit: Improved effectiveness of customer programs requiring integration, including Distributed Energy Resources, Demand Response, and Smart Cities. Improved reliability through implementation of smart grid applications and more efficient use of existing AMI & GIS investments.	SG	175,000
6. **EPRI** P174 Integration of Distributed Energy Resources Increased amounts of distributed energy resources (DER) in the electric grid bring a number of challenges for the electric industry. Utilities face large numbers of interconnection requests; distributed generation on some circuits will exceed the load; and many operating challenges involving feeder voltage regulation, hosting capacity limits, inverter grid support and grounding options are involved. Furthermore, providing reliable service as DER penetrations increase and electricity sales diminish can also add economic and business challenges to the technical ones. This Program addresses these challenges with project sets that assess feeder impacts, inverter interface electronics, and integration analytics. The Program evaluates case study experiences and strategies related to future business impacts. It also evaluates leading industry practices for effective interconnection and integration with distribution operations. Many of these activities support EPRI's "The Integrated Grid" initiative. This Program includes lab and field evaluations and demonstrations of improved DER power management and communications. A primary objective of the work in the field is to expand utility hands-on knowledge for managing distributed energy resources—without reducing distribution safety, reliability, or asset utilization effectiveness. Moreover, the optimal integration of distributed energy resources, like solar photovoltaic (PV) generation, has the potential for significant public benefits. These include reduced climate impact of overall electric power generation, potential for more efficient and optimum operation of the electric system through efficient generation closer to the load and even improved resiliency with local generation to provide power during major events on the grid. Achievement requires making these distributed resources a part of the planning and operation process inherent to an Integrated Grid. Customer Benefit: The research areas provide us with the information to plan, develop, and operate the new T&D grid reliably and efficiently.	SG	71,000
7. **EPRI** Program 180 – Distribution Systems Distribution system owners need to continually improve the efficiency and reliability of the distribution system, to accommodate a higher penetration of distributed energy resources (DER), and to maximize utilization of existing distribution assets without compromising safety and established operating constraints. Significant changes to distribution design and operating	OE	122,000

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practices are needed to accommodate these new requirements. At the same time, utilities will continue to grapple with the ongoing challenges of an aging infrastructure, increasing customer expectations, increasing competition for resources, and an aging workforce. Recent experience with major storm events has also revealed a need to re-examine practices for designing, maintaining, and operating the distribution system to improve its overall resiliency. EPRI's Distribution Systems Program has been structured to provide members with research and application knowledge to support planning and management of the grid today and the transition to a modern integrated grid. The Program delivers a portfolio of tools and technologies to increase overall distribution reliability and resiliency; understand the expected performance for specific components throughout its life cycle; assess methods for evaluating the condition of system components; and develop and test new technologies. The program delivers a blend of short-term tools such reference guides and industry practices as well as longer-term research such as component-aging characteristics and the development of new inspection technologies. Overall, the Program includes research that supports grid modernization and provides tools for planning, design, construction, maintenance, operation, and analysis of the distribution system. Customer Benefit: The research areas provide us with the information to plan, develop, and operate the new T&D grid reliably and efficiently.		
8. **EPRI** P183 Cyber Security This program develops an analysis framework to correlate cyber, physical, and power system events including: • Development of security event scenarios that utilities can adapt to their operational environment • Identification of operational and asset condition data sources to support event detection; and • Results and lessons learned from testing and demonstrating scenario detection in EPRI's lab as well as utility host sites. Utility enterprises are evaluating cyber security threats to their communication networks in a way that integrates that information with other traditional information about equipment health status and power system status. It is now time to integrate this information into a comprehensive and consistent picture, for use by power system operators and communication system operators, in order to provide a system-wide view and to improve coordination of operator responses. This project intends to focus the "Analysis" component of the Integrated Threat Analysis Framework (ITAF) by developing and testing broadly applied use cases and potential data analysis methods to determine when a malicious event has taken place. While the aggregation of data from these domains (Information Technology, Operations Technology, Physical, threat indictors, etc.) provides a view across the entire utility enterprise, determining how to use this information to make decisions will be very challenging. The operational environment will vary day-to-day due to changing conditions (weather, loading conditions, availability of variable resources, planned or unplanned maintenance, etc.) so the use cases must be dynamic and represent a growing knowledge base as opposed to a set of static scenarios. This challenge will require expertise in both cyber security and grid operations. This project coordinates activities of three EPRI research programs: Substations (P37), Grid Operations (P39), and Cyber Security (P183) in a way that is intended to provide broad power industry and public benefits, including better communication between diverse utility personnel and public service personnel. Customer Benefit: This project will provide research in the support pf providing safe, reliable	SR	92,000

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power by identifying digital threats to and remediating vulnerabilities to PGE technology infrastructure. Customers will benefit from increased safety and reliability of the electrical grid.		
9. **EPRI** P199 Electrification for Customer Productivity PGE's industrial and commercial customers are constantly striving to increase productivity and enhance their competitiveness in the global marketplace. In many cases, electrification – i.e., the application of novel, energy-efficient electric technologies as alternatives to fossil-fueled or non-energized processes – can boost utility productivity and enhance the quality of service to these customers. Electricity offers inherent advantages of controllability, precision, versatility, efficiency, and environmental benefits compared to fossil-fueled alternatives in many applications. A lack of familiarity and experience with emerging technologies, however, impedes many customers, particularly small- to medium-sized businesses and civil institutions, from pursuing electrification measures that can improve the productivity and efficiency of operations. Such enterprises would benefit from information and support from PGE. However, electric utilities themselves face obstacles to serving as effective utility partners in this regard. Identifying and measuring the prime opportunities for electrification in a given service territory can be difficult. One of these is the lack of an analytical framework for quantifying the net benefits of electrification strategies – from the customer, utility and societal perspectives. The P199 research program aims to address gaps like this by developing and refining analytical tools and an objective knowledge base of technologies, applications, and markets and facilitating stakeholder networks to help utilities evaluate and pursue electrification opportunities in partnership with their customers. Customer Benefit: This program enables customers to improve productivity, efficiency and competitiveness through electrification.	SG	68,000
10. **EPRI** P200 Distribution and Utilization The distribution system is changing at an ever increasing pace, much more so than any other area in the power system. Much of this has been driven by changes in customer behaviors (e.g. customer adoption of distributed energy resources, net metering etc.). Tools and methods for planning and operating the distribution system were not designed to meet this changing landscape. Distribution systems have been designed for one purpose: reliably serve all customers in a safe and cost effective manner. However in this new era additional objectives must be considered as well, including accommodating high levels of DER, increasing resiliency, improving operational efficiency, and actively using distribution systems to provide bulk system services. Traditional planning methods utilizing rules-of-thumb are no longer sufficient and methods and tools for truly optimizing distribution planning and operational functions are necessary. Tools and technologies, such as distribution management systems, automation systems, protection systems, and planning tools must adapt to facilitate the needs of this new distribution system. New technologies and their integration will be critical to allow distribution planners and operators to meet these goals and realize this concept of an "Integrated Grid." P200 has been structured to provide research and application knowledge to support planning and management of today's grid as well as tomorrow's. The Program includes research that supports grid modernization and provides tools for planners, operators, and analysis experts of the modern distribution system. This program will serve as the hub for all activities related to distribution planning and operations. Customer Benefit: The research areas provide us with the information to plan, develop, and	SG	56,000

<table>
<tr><th colspan="3">PGE R&D Approved Projects for 2019</th></tr>
<tr><th>Brief Description</th><th>Topic</th><th>2019 $$</th></tr>
<tr><td>operate the new T&D grid reliably and efficiently.</td><td></td><td></td></tr>
<tr><td>11. EPRI P87-Fossil Materials and Repairs

Program 87's objective is to provide integrated material selection guidance, corrosion mitigation methods, and repair techniques to improve safety, performance, and reliability - especially as related to Creep Strength Enhanced Ferritic Steels (CSEFS). EPRI research on Post Weld Heat Treatment (PWHT) exemption methods related to grade P91 and other CSEFS can decrease plant outage times as well as reduce operations and maintenance-related costs; this is important as PGE now has many facilities constructed using CSEFS.
Similar to many other utilities, PGE is concerned about the impact of their aging workforce. Program 87 research provides a large body of knowledge to draw and benefit from as plant and associated support staff near retirement. Technology transfer deliverables include materials and repair guidelines, handbooks, technical projects, webcasts, position papers, and conferences/workshops. The program helps manage and reduce the operating risks associated with material degradation and failure. PGE will be hiring a new welding specialist later this year as part of their succession plan, further increasing the value of participating in this program now.
Some of the resources of immediate need that are covered by Program 87 are included below.
• Post Weld Heat Treatment (PWHT) exemption methods related to grade P91 and other CSEFS materials. The high energy small bore piping constructed at Carty used a significant amount of grade P91 piping materials that require post weld heat treatment (PWHT) for any repair. Innovative methods derived from the EPRI program can be used to obtain exemption from this requirement for any field repairs. PWHT is extremely costly and time consuming during repair cycles.
• New weld methods and procedures associated with dissimilar metal welds (grade P91 to P22 and P22 to stainless steel). Dissimilar metal welds are the most common locations for weld failures in the industry due to the stringent material joining requirements applied to these materials.

<u>Customer Benefit</u>: Access and utilization of the research from Program 87 will ensure that all specifications, repairs, acceptance criteria, life management programs, maintenance practices and new project designs incorporate current best practices to maintain asset reliability and operational efficiency. PGE will benefit from the collective experience of the industry in the procurement, acceptance, installation, repair, management and maintenance of the materials found throughout its generating plants.</td><td>SR</td><td>49,000</td></tr>
<tr><td>12. <u>EPRI P198 Strategic Sustainability Science</u>

Power companies face unique challenges and tradeoffs managing financial, environmental, and social performance while providing safe, clean, reliable, and affordable electricity. Leveraging EPRI's decade-long stream of sustainability collaboration and research, the resources and tools developed through this new Strategic Sustainability Science Program will provide electric power companies the opportunity to take sustainability to the next level, embedding it into day-to-day operations and long-range strategic planning; exploring where the most efficient and effective sustainability change is made across the industry's value chain; engaging with cross-sector thought leaders to explore what "sustainable electricity" means and how to enhance effective communications; and using systems thinking to define how the electric power industry fits in a sustainable economy. The Strategic Sustainability</td><td>OE</td><td>49,000</td></tr>
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Science program brings together sustainability leaders to steer progressive work, driving innovative projects that are not currently being done anywhere else in collaboration with member companies and industry stakeholders providing. Resources and tools emerging from this research can help electric power companies increase overall value, operate efficiently, better-mitigate risk, meet growing customer expectations, and enhance engagement with employees and industry stakeholders. The program serves as the future of sustainability–related research for the electric utility industry. Customer Benefit: As noted, PGE's customers have expectations around the sustainability of our business and many of them have sustainability commitments of their own. Participation in this program demonstrates our commitment to sustainability as we seek to build business value while simultaneously acting as environmental stewards and corporate citizens in the communities we serve. This program will provide us the tools to better embed a sustainability mindset at our company, and better communicate to our customers not only how we're working to be more sustainable, but actually engage them in the conversation as we seek to collaboratively and proactively meet their expectations and needs.		
13. PSU – Battery Backup Field Demo; Residential and Grid As electric utilities experience increasing penetration of distributed renewable power generation (wind and solar) resources at the distribution feeder level, there is heightened awareness for the need to ensure acceptable power quality from both safety and reliability perspectives. Energy storage devices will be needed to store energy when it is abundant and to release it when needed.. Development of the energy storage devices will enable the grid to respond with demand side controls and limit peak power demand. If available in sufficient capacity, energy storage devices will help resolve the present "non-dispatchability" of wind and solar power assets which currently dominate the renewable power generation resource stack mix. This development will advance the incorporation of more of these types of renewable power in response to carbon emission reduction policies through the promotion of renewable energy standards (RPS). To accomplish this on a more distributed basis requires that PGE take steps similar those described above for incorporation of renewable power sources such as wind and solar. This can also be done using energy storage alone on a distributed basis. PGE has collaborated with Portland State University's Electrical and Computer Engineering (ECE) Department to take steps in the placement of battery energy storage devices at residential locations. This collaboration will allow the testing and use of a very safe aqueous ion battery that has more energy density than power density, and more suitable for household use. The vision is that PGE would own and maintain the 7 to 8 KW inverter and the nominal 50 kWhr battery as investment assets so that: • PGE, through an agreement with the premise owner, can use the battery • Controls for the battery would enable demand response, wind firming, etc. • Upon loss of utility power a disconnect allows the battery to power the home • Upon re-gaining utility power the inverter will allow automatic grid re-synching • The inverter will also monitor and control for islanding conditions • The meter for the system will track energy for home and grid separately • The meter also supports circuitry to facilitate telemetry, command and control PGE expects the battery will serve PGE's purposes for the vast majority of the time. For the home owner, the battery-inverter will provide the peace of mind of having back-up power for that short period of time that loss of power is experienced on PGE's grid.	ES	67,000

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Customer Benefit: The battery will be supporting the increased penetration of renewable power such as wind and solar.		
14. Data Analytics and Visualization POC This Proof of Concept will engage three vendors (mPrest, OpusOne and innowatts) that will demonstrate their ability to provide high value to PGE's Integrated Grid initiative. The POC will focus on specific use cases, including improved load forecasting capability, identification of under- and over-loaded transformers and the ability to wrap multiple systems into a system-of-systems. Customer Benefit: This POC will provide multiple planning and operational value streams to PGE and its customers. These include: (1) The ability to rapidly integrate multiple systems provides high value by reducing O&M costs and operational miscues that result in poor data used to make capital and O&M decisions. (2) Improved load forecasting would result in the ability for PGE to better manage its operational business during both peak and non-peak events. (3) Improved load forecasting may provide PGE the ability to inject additional energy into the EIM or other markets that may emerge over the next several years. (4) The capability of identifying overloaded and under loaded transformers will reduce the risk of an outage, thereby improving outage metrics and improving the customer experience of PGE's customers. (5) Implementing a data bus approach will reduce human error, lag time between manual updates of multiple systems, facilitate data governance, data analytics and provide a higher-level of confidence in data quality and decision making thereby enhancing decision quality and speed of decision making in multiple areas. (6) Begin to move the needle on PGE's data analytics and visualization in a manner that directly supports the Integrated Grid Strategy. (7) The speed of integration, if realized, will accelerate PGE's development and delivery of an energy exchange platform necessary to support SB978 and corporate goals.	OE	300,000
15. PGE Employee EV Research Program Extension and Data Analysis With the increased penetration of electric vehicles (EV) and supporting infrastructure -- PGE needs to research various concerns as this use ramps up – for example: • charging and driving habits of EV customers • battery life & degradation as it relates to a driver's charging & driving habits • impact of TOU rate schedule on EV charging • commuting habits of EV drivers PGE has pursued this research via studying the driving habits and usage of PGE employees as part of this R&D project. Customer Benefit: Gathering data on electric vehicle driving and charging habits will enhance customer service by ensuring that future transportation electrification programs are designed to meet the needs of electric vehicles with longer driving ranges. Currently, only 2 of our 124 program participants currently own vehicles with ranges in excess of 200 miles due in part to the delays in release of the Tesla 3).	SG	50,000
16. Use Of Imaging & Artificial Intelligence To Enhance Vegetation Management Investigate the use of Lidar and Hyperspectral Imaging in addition to Artificial Intelligence	SG	500,000

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computing to inform and enhance operations in vegetation management, utility asset management, system planning, and other operations. This program concept could be scaled up or down. Initial estimate to get a reasonable sampling size on our system is $500,000. Customer Benefit: This research area will provide allow us to operate and maintain the T&D grid reliably and efficiently, reducing outages and lowering O&M costs.		
17. OSU – Microgrid Synchrophasor, The goal of this project is to better understand load models in order to advance grid protection of the next generation (integrated grid) power transmission and distribution infrastructure. With assistance from the growing PMU network at OSU, a composite dynamic load model can be estimated in real time and provide useful insight into the design of microgrid protection schemes. This will address challenges such as reverse flows, automatic reclosing, or delayed relay tripping. This project will provide PGE and its customers with insights about the benefits of deploying phasor measurement units (PMUs) at the distribution level yielding improved analysis of anomalies from modern, non-traditional loads, as well as synchronization between transmission and distribution level sensing. Customer Benefit: OSU is investigating advanced monitoring and protection techniques for application in an evolving integrated grid. Investing in synchrophasor research at OSU will produce benefits from smart grid knowledge and employee pipeline development. Lessons from this research will aid PGE's business model transition from a mono-directional hierarchical power delivery model to that of customer-centric dynamic power balance services, through developing enhanced operational strategies at the distribution system level. This transition will ultimately support reliability, operational efficiency, energy use optimization, peak shaping, resiliency, and distributed renewable resource integration.	SG	30,000
18. OIT – Second Life Battery Research This project allows PGE in collaboration with Oregon Institute of Technology (OIT), to learn about and implement uses of second life batteries. In particular, there is a desire to better understand the comparative life cycles of Li-Ion, Zinc-Bromide, and Sodium-Sulfur batteries as it applies to grid level storage/islanding applications. The approach would be to obtain multiple types of batteries that are candidates for the second life study: (1) Perform SOC (%), (2) capacity, (3) life cycle, and efficiency, (4) charging-discharging, and reaction time analysis of candidate electro chemistries. This project will deliver a formal, evaluated report with the comparison data. These results would allow PGE to be better positioned to understand how 2nd life uses of long-lived batteries can be cost-effectively applied to other applications that will benefit its customers. These tests will be conducted at Oregon Renewable Energy Center (OREC) under a controlled environment. Customer Benefit: PGE customers will potentially benefit expanded deployment of cost-effective battery storage.	ES	25,000
19. BPA R&D Project (T&D Node/Breaker Modeling) Economic drivers push the power system to operate with leaner margins. Compounded by higher uncertainties introduced by the emerging mix of renewable generation and smart loads, meeting reliability standards and minimizing blackouts and outages are increasingly a bigger challenge.	SG	50,000

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Tackling this challenge requires accurate network node/breaker models. Presently, the calculated path flow based on network models differs from real time values ranging from 100 MW to 900 MW, which is 5% to 25% of the actual flow. Currently there is no single data source where utilities can get an accurate and validated WECC-wide model at any time. The model difference causes reliability issues, inaccurate pricing (LMP) values, and loop flows. Subsequently this negatively impacts congestion mitigation plans. With this in mind, the goals of this proposed project are: - Identify the barriers to a common WECC-wide node/breaker model - Identify techniques and approaches to address the barriers - Develop the requirements to obtain a regional model for BPA, PGE, other ISOs, reliability operators, Peak, and WECC - Reduce external model maintenance efforts for all parties while improving the quality of the model. This proposed work will deliver a report documenting the techniques and requirements, with examples to demonstrate feasibilities. The report will guide the actual development of a set of automation tools that build, validate, maintain, and host the common WECC-wide node/breaker model. Such development is beyond the current proposed work and is intended to be subsequent Phase 2 work. An accurate model is essential for BPA, PGE and other utilities to assess the impact of Energy Imbalance Market (EIM), reliability, congestion mitigation management, Stability Operating Limits (SOL) calculations, Available Transfer Capability (ATC) calculations, as well as accurate forecasts for transmission upgrade projects. Customer Benefit: This research will provide us with the information to plan, develop, and operate the new T&D grid reliably and efficiently.		
20. NEEA End Use Load Research This project involves participating in the End Use Load Research (EULR) Project being managed by NEEA. The purpose of the EULR project is to obtain a representative sample of electric end use load shapes, as this data has not been collected since the 1980s. This data will be collected continuously over a five year period and will be accessible through an online database to participating parties. Customer Benefit: Detailed end use data has a number of important uses for PGE, including informing our deep decarbonization planning, demand response planning, bottom-up forecasting, and rate design.	OE	130,000
21. Distributed Storage for Community Resiliency-PREBHub PGE will support deployment of and research of three community resiliency “PREPHubs”. PREBHub is a concept pioneered by MIT’s Urban Risk Lab to support disaster resilience. Composed of flexible kit of parts, each element serves the community in both every day and emergency scenarios (e.g. solar/battery, radio communications, public Wi-Fi, cached goods, lights, etc.). The City of Portland has expressed interest in demonstrating the PREPHub concept in Portland to create a visible/tangible face for the City’s BEECN network. A BEECN is a temporary radio	ES	65,000

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communications site to go in Portland after a major earthquake to ask for emergency assistance if phone service is down, or report severe damage or injury. There are 48 locations throughout Portland. The PREPHub team is proposing to install three PREPHubs in 2018 across Portland. Each site will include a residential energy storage device (e.g. Tesla PowerWall or Sunverge SIS). During regular operations, the devices will be managed by PGE and PSU as an extension of PGE's existing residential storage demonstration project. During an outage the device will island from the grid and provide backup power to the PREPHub which will power small plug loads (e.g. emergency communications, charging of cell phones, etc.). Further, the units will have small solar arrays to extend power availability for a limited duration in the event of an outage. PSU will use the sites to expand upon existing research on controlling and aggregating distributed energy storage for PGE. Customer Benefit: The project supports benefits for customers in several ways: 1. Directly supports municipal customers seeking community resiliency solutions. During a major event, the batteries will support customer plug loads (e.g. cell phones) which has been identified as a priority by the City of Portland. 2. Though small, the storage devices in the PREPHubs will be used for grid services day-to-day (this includes capacity, energy & ancillary services, etc.) 3. Customers will benefit from the learnings associated with this project. Advancing our learning of aggregation, control, and dispatch of distributed storage has the potential to reduce integration costs for future distributed energy resource programs.		
22. Cascadia Lifelines Project Cascadia Lifelines Program is a targeted research consortium aimed at improving Oregon's infrastructure resilience in a cost and value informed manner. Professor Dan Cox is the director of the program. Regular members at a cost of $50,000/year are ODOT, PGE, NWN, BPA, PDX. Being at this level provides you a seat on the Joint Management Committee. This is an important thing to understand because the Joint Management Committee determines the research projects. This is a continuation of PGE's support over the last five years. Customer Benefit: By co-funding Cascadia Lifelines R&D projects, PGE's customers benefit from a more resilient grid during emergency events.	SY	50,000
23. Smart Streetlights Phase 3 In 2018, PGE engaged Portland State University in a research project to investigate and demonstrate 'smart' streetlights. A market assessment of technologies conducted by PSU supported pursuit of a demonstration pilot project with Sensus, PGE's AMI vendor and Telensa, the world-wide leader in smart streetlight deployments. A two phase demonstration project was initiated. Phase 2 will demonstrate the system's ability to remotely brighten, dim and flash the lights, and to support secure user roles (e.g. shared control) for PGE and municipalities. Completion of this research is critically important to advancing PGE's Municipality Strategy. If this research is not funded through R&D, O&M funds from other sources will be required to complete it.	SG	50,000

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Brief Description	**Topic**	**2019 $$**
Customer Benefit: Smart streetlights will use less energy. Outages will be detected near real-time, improving the PGE's responsiveness to maintenance needs (and improving safety). Municipalities will be able to program streetlights to address specific needs and use cases (e.g. emergencies and traffic conditions). Billing will be done on actual, as opposed to deemed, usage (an interest expressed by a number of municipalities).		
24. Investigating Ductile Iron Poles for T-D Structures Evaluate the use of ductile iron as a viable support structure material in PGE's system. PGE is soliciting the research capabilities of Oregon State University's College of Civil Engineering. This work will support a graduate research assistant for general investigations into the long-term performance of ductile iron poles. This will include a thorough literature review as well as accelerated testing of ductile iron pole sections conducted under three types of degradation scenarios. Those scenarios include: 1) Corrosive environment using OSU's Qfog system 2) Sulfate rich soil environment using either OSU's Qfog or MCMEC system1 3) Placement and initial measurements at OSU's long-term outdoor exposure site. During and after the accelerated aging, OSU will do electrochemical surface measurements (Eis) and scanning electron microscopy (SEM). Additionally, after accelerated aging, all specimens will be placed on OSU's outdoor long-term exposure site for continued monitoring. This will provide PGE with a repository of samples that can be measured periodically and will allow them continual updates, ahead of time, as to the long-term performance of ductile iron pipes. PGE has provided sections of ductile iron pipe and "comparison" pole material samples. Customer Benefit: Ductile iron poles have the potential to improve reliability and resiliency by eliminating woodpecker damage as one of the leading causes of premature wood pole failure. Additionally, the use of ductile iron poles addresses the growing concern around use of treated wood poles in environmentally sensitive areas.	SR	20,000
25. PGE EV Infrastructure Smart Charging Pilot The goal of this project is to evaluate the feasibility of using public electric vehicle charging infrastructure as a demand response resource. PGE owns and operates four 50 kW DC fast chargers and two 7.2 kW level 2 charging stations for public use on SW Salmon Street between 1st and 2nd Avenues. These stations are operated using the Greenlots software platform and, by upgrading the platform to include a demand response module, PGE would be able to call demand response events. This project would test multiple event deployment methods, including automatic curtailment, optional curtailment (ask users if it is OK to limit charging rates), and price signals (pay more to opt out). User feedback will also be requested. Customer Benefit: Evaluating public electric vehicle charging infrastructure for inclusion in future demand response programs benefits PGE's customers by exploring new resources for peak demand reduction. This project will also benefit customers by ensuring that future demand response programs are well designed, enhancing customer experience.	SG	20,000
26. Salem Smart Power Center (SSPC) Voltage Control In 2016, PGE completed a project at the Salem Smart Power Center (SSPC) to prove	SG	75,000

PGE R&D Approved Projects for 2019		
Brief Description	**Topic**	**2019 $S**
that the facility's 20 inverters could effectively and precisely control the voltage on Oxford Rural Feeder. This demonstration was successful, but it is not possible to keep the SSPC left in the voltage control mode because the inverter control system will interact negatively with the voltage regulators in the substation. The voltage control mode can operate autonomously if appropriate controls and communications are installed to interface with the voltage regulators in a safe and consistent manner. This project consists of installing controls at the substation to use the voltage regulators for course voltage control and allowing the inverters to perform fine control. Also, controls will be installed that revert voltage control to the voltage regulators when the system exceeds high or low voltage limits. Customer Benefit: This project would result in a feeder voltage with much lower variation than a typical PGE feeder. The Oregon State Data Center which is located on this feeder has expressed that there is a value in this to them for reliability. If the feeder voltage can be optimized to maintain the lowest voltage possible while not violating ANSI standards for voltage (+/-5% of nominal), customers will realize a modest savings in energy usage. This application will reduce the number of operations of the voltage regulators by a significant amount (possibly as much as 50%). This application will demonstrate the ability of smart inverters to enhance the integration of solar energy by diminishing the voltage fluctuations sometimes experienced with distributed solar PV systems. PNNL's report predicts an economic benefit of $393,000 to the NPV over the 20 year life of the project by implementing this control.		
27. Ultra Capacitors Industry wide, failure of starting batteries contributes to 70% of generator 'fail to start' problems. Compared to the traditional lead-acid starting batteries, ultra-capacitors offer 6 times the lifespan, 3 times the cranking amps and are less susceptible to temperature fluctuations. ultra-capacitors are also more energy efficient as they use less energy to float charge and have faster recharge between cranking attempts. DSG regularly and prescriptively changes existing lead acid batteries for DSG generators. If the project is successful, we could start the changeover to ultra-capacitors from lead-acid technology. There would be a direct benefit to the DSG customers served by a successful ultra-capacitor test, and indirect benefits to all our other customers (by making DSG more cost effective and resilient). Future benefits to customers could include energy savings if the technology could replace less efficient battery systems for other applications. This project will be a good entry point into the ultra-capacitor market for PGE – as the technology improves, we believe the use of ultra-capacitors will increase dramatically. Customer Benefit: There would be a direct benefit to the DSG customers served by a successful ultra-capacitor test, and indirect benefits to all our other customers (by making DSG more cost effective and resilient). Future benefits to customers could include energy savings if the technology could replace less efficient battery systems for other applications. This project will be a good entry point into the ultra-capacitor market for PGE – as the technology improves, we believe the use of ultra-capacitors will increase dramatically.	SY	40,000

PGE R&D Approved Projects for 2019		
Brief Description	**Topic**	**2019 $$**
28. Wave Energy – OSU To advance Wave Energy and Modeling Research at OSU. This project would provide support for the continued expansion of wave energy research & modeling, prototype linear test-bed testing, and resource evaluations being used to asses renewable energy potential in the Pacific Northwest. Customer Benefit: Advancing wave energy research will provide the benefit of encouraging new project development in Oregon. This would allow increased diversity in PGE's renewable resources portfolio.	RP	25,000
29. Solar PV Monitoring Lab - U of O The University of Oregon collects data from a network of 30 Pacific NW monitoring stations. They submit this data to the National Renewable Energy Lab (NREL) and post this data on a Public website. The U of O maintains this network of solar PV monitoring stations. Customer Benefit: PGE's customers will benefit from the clean energy output from solar PV resources.	RP	25,000
30. BPA Collaboration - Coordinated Voltage Control The object of this research is to develop, simulate and validate a coordinated voltage control scheme for increasing Dynamic Transfer Capability on California-Oregon Intertie and Pacific HVDC Intertie. This project will develop algorithms for coordinated voltage control and optimization of reactive power resources to increase DTC limits on the interties and internal flowgates. Customer Benefit: Optimizing the use of PGE transmission will reduce energy costs for PGE customers.	OE	50,000
31. Fiber Optic Current Sensors (FOCS): The FOCS technology has evolved into being of practical use for primary relaying current measurement in several distribution and transmission facilities. The benefits for this technology are: - Safety - Conventional Current Transformer shock and energy hazard related accidents will be eliminated - Fault current measurement inaccuracy caused by conventional current transformer saturation will be eliminated - Errors caused by analog to digital conversion to IEC 61850-9-2LE sampled values of conventional current transformers will be eliminated - Decreased handling and installation time when responding to conventional free standing CT replacements during severe outage events (e.g., seismic) The following will be performed on the two Fiber Optic Current Sensors benchmarked in the R&D exploratory project: - Test for compliance to IEEE 693-IEEE recommended Practices for Seismic Design of Substations - Confirm relaying current measurement accuracy - Confirm fault transient performance specifications - Determine if the effects of series and/or back to back shunt capacitor switching causes	SG	50,000

PGE R&D Approved Projects for 2019		
Brief Description	**Topic**	**2019 $$**
undesirable FOCS and Merging Unit operation - Measure and record real time data from staged fault testing of the installed FOCS Customer Benefit: The total estimated cost for this Project is $500k, PGE's share will amount to a fraction of this ($50,000 x 2 years) and provide full access to all of the learnings.		
32. Floating Solar PV Use a consultant to develop a project for installation of floating solar PV on PGE plant reservoirs. The integration of floating PV panels would allow shading and power generation. Shading of a reservoir helps to lower water temperature – better for fish habitat and decreased evaporative loses. The addition of solar PV at plant sites is ideal as interconnection, communications, metering, and O&M staff already exist. This type of installation could be used at the Carty Reservoir, PRB (i.e., Lake Billy Chinook, Lake Simtustus), and Faraday Lake. Customer Benefit: More renewable power in PGE's resource mix.	RP	40,000
33. Beaver Holding Ponds Install, test and verify Carbon Dioxide gas injection as a means to control PH at Beaver Generation station holding ponds. Liquid sulfuric acid is currently used to control PH in the holding ponds. During the summer months a large quantity of acid is used which exposes Beaver Technicians to acid while totes are exchanged. Carbon dioxide may potentially be used as a substitute to create carbonic acid. Customer Benefit: This project will improve safety by reducing exposure to a highly corrosive acid. The substitution of bottled Carbon Dioxide gas can significantly reduce potential acid spills and allow for easy, modular refills. In addition, carbon dioxide is approximately $0.14 per pound less than sulfuric acid. This project could result in significant savings to PGE if the project is determined to be applicable at other thermal facilities.	S	150,000
34. Renewable Fuel Use for Dispatchable Standby Generation (DSG) Test the environmental, maintenance, performance and cost impacts of using a renewable Diesel alternative fuel on emergency backup generators. The data and lessons learned will be an input to a recommendation to switch fuels. Customer Benefit: The Dispatchable Standby Generation group works with 86 customer owned emergency generators at 58 sites. We work closely with 38 different customers to provide a key service for critical backup emergency systems. The ability to offer a PGE tested and approved diesel fuel alternative would be very valuable to these customers, the customers that they serve and members of the community in which their generators operate.	RP	50,000
35. PW2 Waste Heat Recovery Energy The operation the PW2 reciprocating engines produce a large amount of waste heat form cooling the engine blocks. This waste heat could be used to produce additional energy via an Organic Rankine Cycle system. This project would hire a consultant to determine the amount of waste heat available from PW2 operation and the optimum organic motive fluid. This project would also determine the economic feasibility – with the goal of preparing a capital job for the CRG.	RP	20,000

PGE R&D Approved Projects for 2019		
Brief Description	**Topic**	**2019 $$**
Customer Benefit: PGE customers would benefit from an additional source of clean energy via waste heat recovery.		
36. Power to Gas – NWN This project will demonstrate, test, evaluate, and advance technical specifications for commercial production of hydrogen from electrolysis and methane production from woody biomass. This process will also provide ancillary grid balancing services to the grid. The proposed system will produce renewable natural gas (RNG) for PGE power plant fuel. The process uses the PyroCatalytic Hydrogenation (PCH) from G4 Insights – low temperature thermochemical production of RNG from lignocellulosic biomass. The electrolyzers will use excess renewable energy (e.g., during Spring runoff, peak solar, high regional wind) to produce hydrogen and can act as Dispatchable Load Customer Benefit: PGE's customers will benefit from cleaner production of energy form PGE's gas fired plants.	RP	25,000
37. PW2 Black Start Load Bank Port Westward 2 is capable of providing Black Start for PGE's grid. Currently the plant can inject energy in to a load bank at the Trojan substation. As an alternative, a large chiller could be installed at Port Westward. During Black Start testing or during periods of low load – Plant energy could be used to operate the chiller. Then during peak loads – the energy can be recovered by mixing cold air from the chiller in to the Gas Turbine inlet to significantly improve unit Heat Rate. The CCCT already has an injection grid on the GT intake that the anti-icing system uses. Hire a consultant to evaluate the cost/benefit of integrating a chiller and if economic – prepare a Capital Job project for the CRG. Customer Benefit: PGE customers would benefit from the chiller acting as a Load Bank to allow reliability black start testing and have a lower cost of energy from PW1 due to improved Heat Rate.	OE	20,000
38. Fuel Gas from Landfills - Wastewater Treatment Plants Use a consultant / search engine to identify all landfills and wastewater treatment plants in the PGE Service Area. Contact owners/management at the identified sites to determine opportunities for recovery of flared methane gas to be used in firing onsite gensets. The energy produced can be used to supply the grid. Customer Benefit: PGE customers will benefit from additional renewable energy integrated to the grid.	RP	30,000
39. South Metro Area Regional Transit Electric Bus Project PGE will fund Portland State University's evaluation of customer-owned bus smart charging, including night-time wind following to support renewables integration. Results from the research will inform future charger deployments, potentially adding additional value streams and capturing additional environmental benefits associated with transportation electrification. Customer Benefit: PGE customers would derive benefit from the integration of more renewable resources and possibly avoided T&D expenditures if the chargers allow more efficient utilization of grid infrastructure.	SG	35,000

PGE R&D Approved Projects for 2019		
Brief Description	**Topic**	**2019 $$**
Total (Original Projects as filed in PGE Exhibit 503)		**$3,070,000**
Additional 2019 Approved Projects		
40. EPRI P64 - Boiler and Steam Turbine Cycle Chemisty Safety and availability loss due to failures are two key issues driving R&D on major fossil power plant components, especially in older plants. Operators need to minimize major causes of lost availability and associated maintenance costs related to corrosion and inadequate cycle. By using the results of the R&D in this program, members can: • Improve overall unit availability and flexibility: Losses due to improper chemistry have a 1% or more effect on unit availability • Reduce steam turbine efficiency losses: Chemical and metallic oxide deposits reduce turbine efficiencies by up to 2% Customer Benefit: Research developed from Program 64 will allow PGE to be proactive in finding and mitigating potential issues before those issues result in unwanted forced outages.		33,043
41. Biglow Wake Effect – Portland State University This project proposes research to optimize the blade length and rotor rotation for the Siemens wind turbines at Biglow Canyon Wind Farm. This will increase the performance/output at PGE's Biglow Canyon Wind plant and thus its overall power output with potentially only small capital outlay. The optimization research and resulting power modelling validation would utilize the wind tunnel available at PSU. Customer Benefit: Optimizing Biglow Canyon Wind Farm output will reduce energy costs for PGE customers and increase renewable energy output.	OE	15,000
Total (Added Projects after filing of PGE Exhibit 503)		**48,043**
Grand Total 2019 Approved Projects		***$3,118,043***

May 7, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 284
Dated April 23, 2018

Request:

Regarding the stated increase in talent acquisition and technical training of $0.9 million (Lobdell-Batzler 500/6 and work paper "Corporate Support 2019"),

a. **Regarding the associated increase of 3.9 FTE, please provide a narrative explanation of duties of those positions and if the positions are currently filled.**
b. **Regarding the associated non-labor costs,**
    i. **Please identify the specific incremental costs being added (e.g. employee benefits, contract services, equipment, supplies, etc.) and how the costs directly support the Company's training and talent acquisition goals.**

Response:

a. The referenced FTE increase is due to four new positions added in 2018 to support increased demands on PGE's Talent Acquisition and Technical Training departments. All four positions are essentially filled.

   Two positions were added to support Talent Acquisition:
   1. PGE added a senior-level Recruiting Specialist was added to recruit and hire candidates, train PGE managers and supervisors on corporate hiring policies and procedures, and provide project management support. This position is currently filled.
   2. In addition, PGE added an entry-level Recruiting Specialist to assist recruiters with developing candidate pools, scheduling phone screenings, and arranging background checks and drug tests. This position is currently vacant. However, until this FTE position is filled, a temporary contractor is currently in this position.

   Two senior-level Training Specialists were added to PGE's Technical Training department in 2018 to support the expansion in PGE's training demands. The positions are responsible for developing, facilitating, and managing training programs that train employees on key skills and abilities necessary for their roles. Both positions are currently filled.

b. The primary non-labor cost increase for Technical Training is outside services support for: 1) an increased volume of third-party background checks and drug tests on prospective employees, and 2) implementation of diversity and inclusion programs and events. These costs directly support Talent Acquisition’s goals of promoting a safe and diverse place of business, free from the effects of illegal substances.

The primary non-labor cost increases for Technical Training are: 1) non-PGE temporary labor used to backfill existing trainers that are overseeing the development of Customer Engagement Transformation (CET) and transmission and distribution (T&D) organizational training, and 2) additional materials and supplies needed for new CET and T&D trainings. These costs directly support Technical Training’s goal of ensuring a skilled workforce.

May 7, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 285
Dated April 23, 2018

<u>Request:</u>

Regarding the remaining increase in HR/Employee Support from 2017 to 2019 ($2.3 - .09 = $1.4 million) (Lobdell-Batzler 500/2 Table 1 and work paper "Corporate Support 2019",

c. Please provide a narrative explanation, for each HR support services area (RC code), including the following,
- **i. The increase in FTE including a description of duties of those positions and if the positions are currently filled.**
- **ii. Please identify the specific incremental non-labor costs being added (e.g. employee benefits, contract services, equipment, supplies, etc.) and how the additional costs will benefit ratepayers.**

<u>Response:</u>

i. The FTE increase occurs within departments 722, 803, 813, and 819. The FTE increase for department 722 is attributed to an entry-level administrative position being vacant in 2017 due to the FTE's participation in a cross-training opportunity. However, this FTE will return to the department in 2018. In addition, a senior-level administrative position was added in 2018 and is currently filled. These positions provide record and information management support by archiving and organizing documents for regulatory and institutional purposes.

The FTE increase for department 803 is attributed to two positions added, as detailed in PGE's 2018 General Rate Case (UE 319). However, after reassessing the business needs of the Human Resources organization, one of these positions was moved to department 807 to provide analytical work force management support for Talent Acquisition[1] and is currently filled. The other position is responsible for analytical support to manage human resources data and is currently vacant. However, PGE is in the process of reviewing applicants who applied to the listing on its iGreentree candidate website.

[1] See Lobdell – Batzler / 8, lines 8-14 for additional information.

The FTE increase for department 813 is attributed to two administrative positions added in 2018. These positions provide back-office support for the entire Human Resources organization and are currently filled.

The FTE increase for department 819 is attributed to two positions added, as detailed in UE 319. However, after reassessing the business needs of the Human Resources Organization, the senior-level analyst position was transferred from department 819 to department 812 to provide labor relations support. Duties include investigating grievance claims with management and business representatives, leading negotiations for various labor agreements, and conducting in-house investigations and interviews on labor issues and provide recommendations on various employee issues. This position is currently vacant and posted to PGE's iGreentree candidate website. In addition, a Consultant-level position was transferred from this department to department 802. This position provides consultation and guidance on complex business, leadership, employee, and labor relations issues within designed business units on Human Resources programs, policies, and guidelines. This position is currently vacant and posted to PGE's iGreentree candidate website.

ii. The primary non-labor cost increases within the Human Resources organization occur in departments 812, 818, and 819. The remaining departments have decreasing non-labor costs.

For department 812, the primary non-labor cost increase is outside services support needed for labor negotiations in 2019. These costs will benefit customers by ensuring that PGE builds and manages its professional relationship with represented labor in order to attract and retained qualified labor for in-demand positions (e.g., journeymen linemen).

For department 818, the primary non-labor cost increases are: 1) outside services support to improve MyTime reporting and 2) non-PGE temporary labor support to fill the need for an administrative assistant who was transferred from this department to department 813. These costs will benefit customers by ensuring that PGE has the necessary resources to support its workforce effectively.

For department 819, the primary non-labor cost increases are attributed to increased allocated benefit costs by means of PGE's labor loadings process, as discussed in PGE's response to OPUC Data Request No. 196. The benefit loading amount applied to department 819 increases due to: 1) an increase in the benefit loadings rate, which reflects higher benefit costs, and 2) an overall increase in department 819 labor costs, resulting in a higher amount of benefit loading costs applied to this department's A&G labor. PGE Exhibit 400 details benefit costs and PGE's overall compensation strategy. In addition, non-labor costs are increasing due to additional outside services support to implement and oversee safety initiatives, including MySafety upgrades, driver safety training, and safety stand-up programs. These costs benefit customers by ensuring that PGE promotes a safety-focused culture, improving employee safety both on and off the job.

May 7, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 286
Dated April 23, 2018

Request:

Regarding the $0.4 million reduction in the Human Resources budget (Lobdell-Batzler 500/9),

d. **Please identify the specific reductions being taken and explain specifically how the reduction is accomplished in the Company's UE 335 work papers.**
e. **Please explain how the reduction is "to reflect the outcome of UE 319" and provide a reference to the relevant Commission order.**

Response:

d. The specific reductions are determined at the departmental level and across several cost elements. As a result, they are not easily identifiable. However, managers within Human Resources use their discretion to achieve targeted budget reductions. The $0.4 million reduction in the Human Resources budget is reflected in PGE Exhibit 500, work paper "Corporate Support 2019", "Core Data" tab under department 809, cost element 2200, accounting work order (AWO) 3000000454 ("Budget Adjustment"). See also row 3231 of the "A&G by RC" tab.

e. In UE 319, the Stipulating Parties agreed to reduce PGE's filed test year operation and maintenance and administrative and general expense by $2.394 million.[1] The referenced $0.4 million reduction partially reflects that adjustment. Other reductions within A&G are reflected under the same AWO (i.e., "Budget Adjustment") in PGE's "Corporate Support 2019" work paper and total approximately $2.0 million. The remaining reductions are embedded in PGE's 2018 budget and are not identifiable as single line-item entries.

[1] See Commission Order No. 17-511, page 5.

CASE: UE 335
WITNESS: JEFFREY WATSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

June 6, 2018

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

A. My name is Jeffrey Watson. I am a Consumer Services Analyst with the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. My testimony will discuss my analysis and recommended adjustments for Portland General Electric's (PGE or Company) expenses related to the following topics: advertising and promotions; meals, travel, and awards; the Fee-Free Bank Card program; and non-labor customer service spending.

Q. Did you prepare any exhibits for this docket?

A. Yes. In addition to my witness qualification statement, I prepared the following exhibits:

- Exhibit Staff/602, which is the Company's responses to Staff DR Nos. 161, 162, and 171-174,
- Exhibit Staff/603, which is the Company's confidential response to Staff DR No. 287, and,
- Exhibit Staff/604, which summarizes Staff's proposed adjustments.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ADVERTISING AND PROMOTIONS

Q. Is there a rule that determines how the Commission should evaluate a Company's spending on advertising and promotions?

A. Yes. Oregon Administrative Rule 860-026-0022 (Presumption of Reasonableness of Advertising Expenses in Utility Rate Cases) concerns the amount of advertising expenses a company may recover through rate proceedings. The rule requires the company to organize advertising expenses by purpose, into the following categories:

- Category "A" — Energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses;
- Category "B" — Legally mandated advertising expenses;
- Category "C" — Institutional advertising expenses, promotional advertising expenses and any other advertising expenses not fitting into Category "A," "B," or "D";
- Category "D" — Political advertising expenses and nonutility advertising expenses; and
- Category "E" — Energy efficiency or conservation advertising expenses that relate to a Commission-approved program.[1]

A company's advertising expenses are evaluated for inclusion into rates using the following criteria:

[1] OAR 860-026-0022(2).

- Category A spending is presumed to be just and reasonable, provided that expenses are 0.125 percent or less of gross retail operating revenues.
- Category B spending is presumed to be just and reasonable.
- Category C spending requires the company to prove that expenses are just and reasonable if they seek to recover costs through rates.
- Category D spending is presumed to be not just and reasonable.
- Category E spending may be capitalized with Commission approval.[2]

Q. How did Staff analyze the Company's advertising spending?

A. Staff reviewed the Company's spending summary to determine if the amount included in the forecasted test year matches the rule as written. As the Company is not seeking recovery of Category D or C spending, and Category B spending is presumed just and reasonable, the focus of the analysis was on Category A spending.

The Company forecasts an amount of Category A advertising expense that is less than 0.125 percent of its gross retail operating revenues for the 2019 test year. Under OAR 860-026-0022(3)(a), the Company's forecasted expense is presumed just and reasonable.

Q. Does your analysis show that the Company should be allowed to recover the full amount of their requested advertising budget in rates?

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[2] OAR 860-022-0026(3).

A. Yes. Staff found no information to rebut the presumption the forecasted amount of Category A spending is just and reasonable and should be included in PGE's test year.

ISSUE 2. MEALS, TRAVEL, AND AWARDS

Q. What is the Company's proposal for meal, travel, and award expenses in this filing?

A. The Company did not provide testimony or exhibits that specifically reference forecasted expense for meals, travel, or awards. In its response to SDR No. 57, the Company included entries for cost elements related to these categories:

- Meals: Business Meals & Entertainment; Salmon Springs Catering; Union Meals & Incidental Exp
- Travel: Airfare; Auto Rental; Conf and Course Rgst Fees; Lodging; Mileage-Non Taxable; Mileage-Taxable; Offsite Room Rental; Other Business Travel Expense
- Awards: Employee Incentives and Bonus; Employee Recognition (excluding gross earnings related to payroll)

Q. How does the Commission normally adjust spending related to these categories?

A. In Docket No. UE 197, the Commission adopted Staff's principal that costs for meals and entertainment, office refreshments and catering, gifts and awards are discretionary and should be shared equally by ratepayers and shareholders.[3] Business-related travel expenses are generally allowed full

[3] Order No. 09-020, pp. 20-21.

recovery. In addition, Staff will recommend disallowance of amounts in any of these categories that appear to be imprudent or excessive.

Q. How did Staff analyze expense related to meal, travel, and award spending?

A. Staff began by compiling the data provided in the Company's response to SDR No. 57 (see above summary) and reviewing spending in the 2017 base year to ensure proper categorization on the part of the Company. This gave a clear picture of the bulk of company spending for each category, but did not provide an opportunity to capture related expenses that were allocated to different elements.

To address this, Staff excluded the cost elements listed above from the DR 57 table and conducted a keyword search across all remaining elements for phrases related directly to the topics of meals, (Keywords: Coffee, snack, breakfast, lunch, dinner, meal), travel, (airport, travel), and awards (prize, award). These were added to the totals from the previously captured spending.

Q. Please describe the analysis Staff conducted on the expenses related to meals, travel, and awards.

A. While Commission precedent provides a clear method for adjusting expenses related to meals, travel, and awards, Staff felt it was appropriate to review the descriptions of the entries related to these topics to ensure PGE's spending for these categories is reasonable. The Company provided a table with expanded descriptions of the expenses in response to Staff DR No. 287. Staff reviewed these expenses by category, and was satisfied that the spending related to meals and awards did not include any entries that were clearly inappropriate or appeared imprudent and adjusted spending at 50 percent, per Commission precedent.

In reviewing the spending entries related to travel, however, it became clear that many of the entries were a mix of meal and travel spending. For example:

- “Hotel and 2 meals for symposium”
- “lodging and some meals”
- “Hotel and meal for self - CS Week”

There were also entries expensed to travel whose description indicates the entire entry was for meals:

- “conference meal”
- “Claims Luncheon (all groups)”
- “dinner while in Columbus OH for Utility Ec. Dev. Assoc. Summer Forum. Troy serves on the board of this organization.”

Since some entries included a mix and some entries were dedicated just to meals, Staff felt it would be reasonable to allocate half the cost of these specific entries to meals. Using the Commission precedent to adjust meals at 50 percent, Staff recommends an adjustment of 25 percent to these mixed-purpose travel entries, while allowing full recovery of other travel expenses in rates.

Q. Is it possible that your travel adjustment is “double counting” meal expenses that were already adjusted?

A. No. None of the entries included in this adjustment had been previously adjusted for meal expenses, as they were not included in the meal related cost elements or the meal keywords from the remainder of the SDR 57 spending.

Q. Please summarize your proposed adjustment for meals, travel, and award spending.

A. Staff's proposed adjustment is summarized in confidential Exhibit Staff/604.

ISSUE 3. FEE FREE BANK CARD PROGRAM

Q. What is the Fee Free Bank Card Program?

A. The Fee Free Bank Card Program ("FFBC Program" or "Program") refers to residential customers' ability to pay their bill using a debit or credit card without a transaction fee. Prior to introduction of the Program, customers were assessed a charge when paying a bill with a credit or debit card. Now, the fee associated with these transactions for residential customers is spread to all ratepayers. The amount included in rates to cover the costs of these transactions has grown as more customers use the Program.

Q. What is the Company's proposal for expenses related to the FFBC Program in this filing?

A. The company has not made a specific request for additional funding for the FFBC Program. Staff determined that this rate case was an opportunity to review the settlement agreement reached in UE 319 regarding projected Program expenses, and analyzed the reported expenses. This would allow a correction to the expenses agreed to in that settlement, if necessary.

Q. What was the settlement agreement for FFBC Program expenses in Docket No. UE 319?

A. In Docket No. UE 319, Staff concluded that previous expectations by PGE and Staff regarding customer adoption of fee free bankcard payments were overly optimistic, and that PGE was collecting more in rates for these bankcard transactions than was warranted. Staff noted that the customer adoption rate was increasing, but not as rapidly as expected. Staff also believed that the amount included in PGE's revenue requirement was based on an overestimation of the cost per transaction.

The stipulating parties agreed to a per-transaction rate that resulted in a test year expense reduction of $0.503 million.

Q. Please describe your analysis of this issue.

A. Staff requested data from PGE regarding the number of costs and transactions through the end of 2017, as well as projected costs and transactions through the end of the test year. Staff analyzed the Company's projections to determine if their growth is in line with the assumptions settled on in Docket No. UE 319. The Company's responses to Staff DR Nos. 171-174[4] provided the data for Staff's analysis.

The data show actual costs per transaction for 2017 are once again lower than projected by the Company. Staff's analysis also shows the cost per transaction has been consistently decreasing since the beginning of the Program.

Staff determined that an adjustment based on the trending cost per transaction of the FFBC Program would be appropriate. Assuming costs stayed flat into 2019 consistent with the trend, the cost per transaction should remain the same as the Company's 2018 projection. However, Staff also found that PGE's projected growth in total transactions for the remainder of 2018 and the test year were relatively flat, which goes against the historical trend.

[4] PGE provided a revision to Staff DR Nos. 171-174 on May 24, 2018, which did not provide an adequate opportunity for staff to review the changes prior to filing. The revisions will be reviewed and Staff testimony will be updated if they lead to changes in Staff's analysis or adjustments.

To determine a more reasonable projection for total transactions, Staff took the average of the first three months of 2018 (the only months for which actual data was available at the time of this writing) and multiplied by twelve to reach a new average estimated number of transactions for 2018. Staff then measured the rate of change in total number of transactions from 2015 through Staff's projection of 2018.

This analysis established a trend from which Staff was able to estimate the rate of change for growth in total transactions for 2019, which is 4.7 percent. Applying this growth rate to Staff's projected number of transactions for 2018 provides the estimated number of transactions for the test year used in Staff's adjustment. Staff multiplied the difference between this cost per transaction and the Company's cost per transaction by the Staff's projection of total number of estimated transactions for the test year to determine projected Program costs for the test year. The difference between the expense for the Company's projection and Staff's projection is Staff's recommended adjustment.

Q. Does your adjustment consider expenses for the FFBC Program other than the cost per transaction?

A. Yes. The Company stated in its response to Staff DR No. 171, "When PGE implemented the rule limiting fee free bankcard transactions (FFBC), we inadvertently allowed a small number of non-residential customers to take advantage of the service… because we used Schedule 102 as the FFBC qualifier. PGE is in the process of correcting this and when finished, non-residential customers will no longer be able to use the fee free program." Additionally, in UE 319, the Company stated in its response to Staff DR No. 353, "At this time, only residential customers can use the FFBC."

The data provided in its response to Staff DR Nos. 171-179 show the Company has incurred costs totaling $140,134 due to this error. It is clear from the DR responses that the Company never intended for non-residential customers to use the FFBC Program. Therefore, Staff proposes to adjust the total amount of spending related to non-residential customers using the Program, as Staff feels it is inappropriate for ratepayers to bear the burden of the Company's mistake in this instance.

Q. What is your proposed adjustment for FFBC Program expenses?

A. Staff's proposed adjustment is based on confidential information and is included in confidential Exhibit Staff/604.

ISSUE 4. CUSTOMER SERVICE – NON-LABOR

Q. What is the company's proposal for expenses related to customer service – non-labor in this filing?

A. PGE proposes to increase non-labor customer service expenses, excluding uncollectible accounts and the Customer Engagement Transformation (CET), from $16.3 million in base year 2017 to $19.4 million in the test year.[5] This represents an increase of $3.1 million or 9.23 percent. PGE states the total escalation is due to several projects scheduled for 2019, including the Flex Pricing Pilot (FPP) to be fully scalable in 2019, and an additional amount for research and program design/development regarding energy storage, electric vehicles, and other customer-focused goals.

Q. Has the company communicated any changes to their proposal since the initial filing?

A. Yes. As discussed the testimony of Staff witness Mitchell Moore, the Company has reversed a decision to implement a full Flex Pricing program, and will remove these costs from its filing.

Q. Please discuss your review of the remaining increases to customer service expenses.

A. For the remaining expenses, Staff reviewed initial testimony regarding the purpose and costs of the programs covered by the increase, PGE's responses to Staff DR Nos. 161 and 162, which provided spending allocations and

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[5] The uncollectible accounts have been addressed by a settlement in principle. Staff witness Lance Kaufman addresses the CET in his testimony.

detailed information about the studies, and orders from previous general rate cases to determine how the increased spending matches previous requests.

Staff is satisfied that the programs as described represent a reasonable expense, and are aimed at providing better service and options to rate payers. Therefore, no adjustments are proposed to these new expenses.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 335
WITNESS: JEFFREY WATSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

June 6, 2018

WITNESS QUALIFICATION STATEMENT

NAME:	Jeffrey Watson
EMPLOYER:	Public Utility Commission of Oregon (Commission)
TITLE:	Consumer Services Specialist Energy Rates, Finance and Audit Division (ERFA)
ADDRESS:	201 High Street SE, Suite 100, Salem, OR 97301
EDUCATION:	Bachelor of Science, Economics Oregon State University, Corvallis, OR Associate of Arts Chemeketa Community College, Salem, OR

EXPERIENCE: I have been employed by the Commission since January of 2016 as a Consumer Specialist in the Consumer Services Division (Consumer Services), and as an analyst in the Energy Rates, Finance and Audit (ERFA) Division. For Consumer Services, I investigate and resolve customer claims of inappropriate action by regulated utilities and other service providers. For ERFA, I support audits and Cost of Capital modeling. My analysis also covers a variety of other financial and general rate case topics as reflected in the current general rate cases of Northwest Natural Gas Corporation (NWN UG 344) and Portland General Electric Company (PGE UE 335).

Prior to my work at the Commission, I was employed by T-Mobile for six years. First I developed and led continuing education courses, both as a trainer and subject matter expert for 600+ representatives and leaders on customer service and sales operations topics.

Next at T-Mobile, I managed a specialized team of customer service representatives to resolve escalated, executive level, and outside-of-policy customer issues. I reviewed call center operations and developed policies based on my analysis of the issues tracked by my team. I presented and defended my analysis and recommendations to site and regional leadership. My recommendations set performance goals to confirm successful resolution of issues and ensured ongoing service quality.

CASE: UE 335
WITNESS: JEFFREY WATSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602

Exhibits in Support
Of Opening Testimony

June 6, 2018

April 11, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 161
Dated March 28, 2018

Request:

Please provide a breakdown of the projected $0.7 million in costs the company estimates in non-labor costs listed in Exhibit 900, Section II for the residential appliance saturation study; the evaluation of distributed energy resources; and the facilitation of electric vehicle infrastructure for non-residential customers.

Response:

The breakdown of the projected $0.7 million in non-labor costs between the residential appliance saturation study, evaluation of distributed energy resources, and facilitation of electric vehicle infrastructure for non-residential customers is shown in the table below.

Program	Cost
EV Infrastructure for Non-Residential	**$ 280, 619**
Evaluation of Distributed Energy Resources	**$ 144,537**
Residential Appliance Saturation Study	**$ 229,461**
Total	**$654,617**

April 11, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 162
Dated March 28, 2018

Request:

Please provide the actual costs for the previous residential appliance saturation study conducted in 2013, as well as a summary of that study's findings and benefits to ratepayers.

Response:

The actual cost for the Residential Appliance Saturation Study (RASS) conducted in 2013 was $129,733. Benefits to ratepayers are outlined in PGE Exhibit 900, Section II.

Attachment 162-A contains a summary of the study's findings.

UE 335

Attachment 162-A

Summary of the 2013 Residential Appliance Saturation Study

Attached please find a summary report of findings from PGE's 2013 Residential Appliance Saturation Study (RASS), conducted from April 22 through July 31, 2013.

Study Highlights

- Electric space heat market share remains stable at 41% in 2013, while natural gas space heat market share edged up slightly from 50% in 2008 to 52% in 2013. The stability in electric space heat market share is due to a larger share of multifamily connects since 2009.
- Single-family homes are dominated by natural gas heating, while multi-family and manufactured homes use mainly electric.
- Overall residential air conditioning penetration has risen to 82% in 2013 from 72% in 2008.
- Electricity as a main water heating fuel continues to be slightly higher in penetration, up from 54% in 2008 to 56% in 2013. Natural gas as a main water heating fuel declined in penetration slightly from 45% in 2008 to 43% in 2013.
- Respondents who have replaced a refrigerator, dishwasher or clothes dryer since January 2012 are more likely to have a high-efficiency model of that appliance in their home.

KEY FINDINGS:

Space Heat

- Overall electric space heat market share remains stable at 41% in 2013, while natural gas space heat market share edged up slightly from 50% in 2008 to 52% in 2013. The stability in electric space heat market share is due to a larger share of multifamily connects since 2009.
- Single-family homes are dominated by natural gas heating, while multi-family and manufactured homes use mainly electric.
- Only 6% of the population replaced their heating system in the past twelve months. The majority of home owners stayed with the same fuel type after replacement. This is similar to the trend observed in the 2008 RASS.
  - Fourteen percent (14%) of single-family respondents have either added (8%) or replaced (6%) a heat pump since January 2012.Natural gas and electric space heat have begun to converge in new homes since 2005-2006.

Air Conditioning

- Overall residential air conditioning penetration has risen to 82% in 2013 from 72% in 2008.
  - Greatest changes occurred for Single-Family respondents' increased use of central electric air conditioning from 42% in 2008 to 47% in 2013, followed by a jump in heat pump penetration among manufactured home respondents from 38% in 2008 to 50% in 2013. Multi-family respondents increased use of window/wall ac from 30% in 2008 to 36% in 2013.

Water Heating

- Electricity as a main water heating fuel continues to be slightly higher in penetration, up from 54% in 2008 to 56% in 2013. Natural gas as a main water heating fuel declined in penetration slightly from 45% in 2008 to 43% in 2013.
    - Single-family homes heated by natural gas tend to use natural gas for water heat (76%), while manufactured homes heated by natural gas use electricity for their water heat needs (76%).
    - Between 82% and 98% of all home types heated with electricity also use electricity for water heating.

Appliances, Technology & Conservation

- Nearly half of single-family homes are likely to adopt high-efficiency appliances such as refrigerators, dishwashers, and clothes dryers.
- Respondents who have replaced a refrigerator, dishwasher or clothes dryer since January 2012 are more likely to have a high-efficiency model of that appliance in their home.
- Single family homes are most likely to have energy conservation features installed.
- Ceiling/attic insulation and wall insulation are features most often present to make the home more efficient.
- Rental properties are much less likely to have taken energy conservation features installed.
- Manufactured home properties are more likely to have insulated walls and caulking/weather stripping on doors/windows.
- Technology penetration is very high for each housing stock for desktop/laptop computers and mobile/smart phones. Internet enabled devices such as mobile/smart phones, video game consoles, tablet computers and E-readers are projected to grow in adoption.
- Computer penetration is over 90%, followed by penetration of DVD's (70%), and cell phone/smart phone (77%).

April 23, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 171
Dated March 29, 2018

Request:

Provide the actual number of fee free bankcard transactions by month from program inception through December 31, 2017, broken down by residential and non-residential sectors.

Response:

When PGE implemented the rule limiting fee free bankcard transactions (FFBC), we inadvertently allowed a small number of non-residential customers to take advantage of the service and excluded a small number of residential customers with grow operations because we used Schedule 102 as the FFBC qualifier. PGE is in the process of correcting this and when finished, non-residential customers will no longer be able to use the fee free program.

Data regarding PGE's bankcard collections does not contain the FFBC-specific information by residential/non-residential customers as requested. Consequently, PGE's response is based on a payment table from our Banner system that lists transactions where the FFBC criteria has been met, then these counts are separated between Residential and Non-Residential based on whether they are Revenue Class 1 or >1.

The estimated number of fee free bankcard transactions by month from program inception through December 31, 2017, separated by residential and non-residential sectors is shown below.

Month	Year	Residential	Non-Residential
October	2014	34,605	815
November	2014	27,903	685
December	2014	36,187	871
January	2015	42,119	902
February	2015	44,334	901
March	2015	47,121	980
April	2015	45,634	877
May	2015	43,309	892
June	2015	47,283	951
July	2015	47,311	946
August	2015	50,196	1,041
September	2015	49,044	1,078
October	2015	52,468	995
November	2015	48,429	964
December	2015	52,741	1,019
January	2016	55,032	1,057
February	2016	62,233	1,183
March	2016	61,505	1,277
April	2016	56,794	1,158
May	2016	57,563	1,178
June	2016	56,327	1,232
July	2016		

		54,726	1,223
August	2016	62,711	1,342
September	2016	59,517	1,367
October	2016	61,180	1,446
November	2016	56,523	1,291
December	2016	59,669	1,481
January	2017	67,189	1,690
February	2017	67,521	1,520
March	2017	73,834	1,720
April	2017	64,503	1,521
May	2017	69,358	1,545
June	2017	67,953	1,525
July	2017	65,522	1,444
August	2017	70,506	1,671
September	2017	66,824	1,535
October	2017	73,173	1,675
November	2017	64,917	1,513
December	2017	65,927	1,580

April 25, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 172
Dated March 29, 2018

Request:

Provide the projected number of fee free bankcard payments by month beginning January 1, 2018 through the test year, broken down by residential and non-residential sectors.

Response:

When PGE implemented the rule limiting fee free bankcard transactions (FFBC), we inadvertently allowed a small number of non-residential customers to take advantage of the service and excluded a small number of residential customers with grow operations because we used Schedule 102 as the FFBC qualifier. PGE is in the process of correcting this and when finished, non-residential customers will no longer be able to use the fee free program.

Data regarding PGE's actual bankcard collections does not contain the FFBC-specific information by residential/non-residential customers as requested. Consequently, PGE's response is based on calculated estimates using available numbers of customers, transaction amounts, and participation rates.

The number of fee free bankcard transactions by month beginning January 1, 2018 through the end of the 2019 test year is listed below. Actuals for January through March 2018 are separated by residential and non-residential sectors (as described above). PGE's forecasted transactions are based only on the estimated residential adoption rate multiplied by the total number of transactions. This method has been consistently performed since the beginning of the program in 2014, so only residential values are shown for forecast years. PGE expects the above-mentioned correction to be implemented by July 2018.

Month	Year		Residential	Non-Residential
January	**2018**	**Actuals**	75,485	1,753
February	**2018**	**Actuals**	72,689	1,598
March	**2018**	**Actuals**	77,989	1,812
April	2018	Forecast	79,869	N/A
May	2018	Forecast	79,983	N/A
June	2018	Forecast	80,179	N/A
July	2018	Forecast	79,841	N/A
August	2018	Forecast	80,042	N/A
September	2018	Forecast	79,578	N/A
October	2018	Forecast	79,460	N/A
November	2018	Forecast	79,929	N/A
December	2018	Forecast	80,038	N/A
January	2019	Forecast	79,976	N/A
February	2019	Forecast	80,095	N/A
March	2019	Forecast	79,974	N/A
April	2019	Forecast	80,233	N/A
May	2019	Forecast	80,275	N/A
June	2019	Forecast	80,384	N/A
July	2019	Forecast	80,227	N/A
August	2019	Forecast	80,247	N/A
September	2019	Forecast	80,226	N/A
October	2019	Forecast	80,107	N/A
November	2019	Forecast	80,458	N/A
December	2019	Forecast	80,398	N/A

April 12, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 173
Dated March 29, 2018

Request:

Provide the total transaction costs by month of fee free bankcard payments from program inception through December 31, 2017, broken down by residential and non-residential sectors.

Response:

When PGE implemented the rule limiting fee free bankcard transactions (FFBC), we inadvertently allowed a small number of non-residential customers to take advantage of the service and excluded a small number of residential customers with grow operations because we used Schedule 102 as the FFBC qualifier. PGE is in the process of correcting this and when finished, non-residential customers will no longer be able to use the fee free program.

The total transaction costs by month of fee free bankcard payments from program inception through December 31, 2017, broken down by residential and non-residential sectors are shown below. The primary drivers of the variation in monthly cost are: 1) the number of customers participating; and 2) the amounts transacted.

Month	Year	RESIDENTIAL	NON RESIDENTIAL
August	2014	$ 1,087.24	$ 50.64
September	2014	$ 48,625.93	$ 2,263.34
October	2014	$ 41,693.74	$ 1,940.67
November	2014	$ 52,432.14	$ 2,659.03
December	2014	$ 63,526.73	$ 3,120.00
January	2015	$ 66,788.11	$ 2,667.39
February	2015	$ 68,558.00	$ 2,318.96
March	2015	$ 66,291.19	$ 2,463.94
April	2015	$ 65,096.29	$ 2,406.65
May	2015	$ 63,237.16	$ 2,535.44
June	2015	$ 65,613.28	$ 2,698.16
July	2015	$ 69,669.70	$ 2,908.05
August	2015	$ 68,068.12	$ 2,873.86
September	2015	$ 73,015.10	$ 3,349.78
October	2015	$ 65,014.87	$ 2,614.26
November	2015	$ 72,501.83	$ 3,173.49
December	2015	$ 80,688.38	$ 3,116.72
January	2016	$ 86,426.41	$ 2,974.41
February	2016	$ 87,066.16	$ 2,758.57
March	2016	$ 88,407.51	$ 3,381.54
April	2016	$ 78,382.92	$ 2,997.24
May	2016	$ 78,218.15	$ 3,223.78
June	2016	$ 79,034.81	$ 3,612.58
July	2016	$ 84,764.97	$ 3,855.25
August	2016	$ 83,304.11	$ 3,781.36
September	2016	$ 85,385.10	$ 4,188.70
October	2016	$ 78,434.76	$ 3,998.17
November	2016	$ 85,692.80	$ 4,212.68
December	2016	$ 95,226.26	$ 4,886.54
January	2017	$ 99,071.84	$ 4,346.17
February	2017	$ 107,314.88	$ 3,963.47
March	2017	$ 96,147.03	$ 3,878.96
April	2017	$ 95,112.95	$ 4,029.11
May	2017	$ 95,563.21	$ 3,930.79
June	2017	$ 92,124.78	$ 4,150.22
July	2017	$ 99,834.03	$ 4,560.79
August	2017	$ 97,364.27	$ 4,519.73
September	2017	$ 100,973.89	$ 4,702.68
October	2017	$ 85,270.49	$ 3,905.42
November	2017	$ 94,874.16	$ 4,533.14
December	2017	$ 102,863.12	$ 4,686.67

April 25, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 174
Dated March 29, 2018

Request:

Provide the projected transaction costs of fee free bankcard payments by month beginning January 1, 2018 through the test year, broken down by residential and non-residential sectors.

Response:

When PGE implemented the rule limiting fee free bankcard transactions (FFBC), we inadvertently allowed a small number of non-residential customers to take advantage of the service and excluded a small number of residential customers with grow operations because we used Schedule 102 as the FFBC qualifier. PGE is in the process of correcting this and when finished, non-residential customers will no longer be able to use the fee free program.

Data regarding PGE's bankcard collections does not contain the FFBC-specific information by residential/non-residential customers as requested. Consequently, PGE's response is based on calculated estimates using available numbers of customers, transaction amounts, and participation rates.

The transaction costs of fee free bankcard payments by month beginning January 1, 2018 through the end of the 2019 test year is listed below. Actuals for January through March 2018 are separated by residential and non-residential sectors (as described above). PGE's forecasted transactions are based only on the estimated residential number of FFBC transactions multiplied by the average transaction amount by the estimated transaction cost. This method has been consistently performed since the beginning of the program in 2014, so only residential values are shown for forecast years. PGE expects the above-mentioned correction to be implemented by July 2018.

Month	Year	RESIDENTIAL	NON RESIDENTIAL	
January	**2018**	$ 102,725.87	$ 4,021.93	**Actuals**
February	**2018**	$ 105,162.09	$ 3,802.04	**Actuals**
March	**2018**	$ 105,687.34	$ 4,105.32	**Actuals**
April	2018	$ 110,731.02	N/A	Forecast
May	2018	$ 111,485.89	N/A	Forecast
June	2018	$ 112,428.95	N/A	Forecast
July	2018	$ 112,713.55	N/A	Forecast
August	2018	$ 113,310.02	N/A	Forecast
September	2018	$ 114,280.62	N/A	Forecast
October	2018	$ 115,609.12	N/A	Forecast
November	2018	$ 116,952.58	N/A	Forecast
December	2018	$ 118,476.51	N/A	Forecast
January	2019	$ 119,321.80	N/A	Forecast
February	2019	$ 119,949.22	N/A	Forecast
March	2019	$ 120,620.09	N/A	Forecast
April	2019	$ 121,522.48	N/A	Forecast
May	2019	$ 122,271.40	N/A	Forecast
June	2019	$ 123,042.83	N/A	Forecast
July	2019	$ 123,255.34	N/A	Forecast
August	2019	$ 123,756.62	N/A	Forecast
September	2019	$ 124,787.46	N/A	Forecast
October	2019	$ 126,057.94	N/A	Forecast
November	2019	$ 127,874.59	N/A	Forecast
December	2019	$ 129,086.94	N/A	Forecast

CASE: UE 335
WITNESS: JEFFREY WATSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 603

Exhibits in Support
Of Opening Testimony

REDACTED
June 6, 2018

STAFF EXHIBIT 603

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE

ORDER NO. 18-047. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 335 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

SEE ELECTRONIC FILE –

UE 335 Exhibit 603 Watson Company Response to DR 287 CONF.xlsx

CASE: UE 335
WITNESS: JEFFREY WATSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 604

Exhibits in Support
Of Opening Testimony

REDACTED
June 6, 2018

STAFF EXHIBIT 604

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 18-047. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 335 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 335
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

June 6, 2018

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

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

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss Staff's analysis and recommendation regarding Portland General Electric Company (PGE)'s request for an increase the amounts collected in base rates for Level III storms from $2.6 to $3.8 million. I also recommend the removal of $2.4 million in base rates for a demand response pilot program.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/702, which is my workpaper showing the financial impact of 2017 storm damage losses.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. MAJOR STORM ACCRUAL

Q. Please summarize the Commission's historical treatment of PGE's Major Storm Damage Accrual.

A. Commission Order 10-478 (UE 215) allowed PGE to collect $2 million annually in rates to pay for service restoration following severe storms, categorized as Level III storms.[1] The annual amount for recovery was based on a rolling ten-year average of Level III storm costs, adjusted to reflect present value costs. To the extent that amounts collected are not used in a given year, the funds are accrued and used to offset costs related to Level III storms in future years. In Docket No. UE 319, the Commission approved the parties' stipulation increasing the annual amount recovered in rates from $2 million to $2.6 million based on an updated rolling 10-year average of Level III storm costs from 2007-2016.[2]

Q. Describe PGE's proposal in this case regarding cost recovery for major storm damages.

A. PGE makes three proposals related to rate recovery for Level III storm costs in this case. First, the Company proposes to increase the amount collected in rates from the current level of $2.6 million established in Docket No. UE 319 to $3.8 million to reflect an updated 10-year rolling average.[3]

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[1] Level III storms are those that meet certain defined criteria, e.g. greater than 50,000 customers out of service; 3-4 regions experiencing outages; greater than 72 hours to restore service; need to call outside assistance.
[2] See Order No. 17-511 in UE 319.
[3] PGE/800, Nicholson-Bekkedahl/15.

Second, PGE proposes to establish a balancing account for costs incurred during Level III storm events and amounts recovered annually in rates. When major storm costs exceed the balance accrued in rates, the account would become negative and could be offset in subsequent years when the cost of storms is less than the annual accrual amount.[4] Finally, PGE requests that the Commission approve PGE's deferral application filed in January of 2017 seeking recovery of $11.4 million Level III storm costs incurred in 2017, be approved and the deferral of $11.4 million be included in the balancing account.

Q. What reasons does the Company provide for its requests?

A. PGE explains that the frequency of Level III storms in recent years has caused the Company to incur recovery expenses above the amount collected and accrued in rates. As described above, there were several storms in 2017 that resulted in a total of $11.4 million in restoration costs.[5] The annual collection amounts set in previous rate cases, based on a 10-year rolling average of costs, has resulted in a deficit in PGE's storm accrual balance.

Q. What is PGE's current "deficit" in storm recovery costs?

A. As of the end of 2017, PGE's negative storm accrual balance is ($12,640,981), inclusive of the $11.4 million incurred in 2017.[6]

Q. Please summarize Staff's recommendation with regard to PGE's requests related to major storm cost recovery.

[4] PGE/800, Nicholson-Bekkedahl/15-16.
[5] PGE/801, Nicholson-Bekkedahl/2.
[6] Ibid.

A. Staff recommends that the Commission:

1) Approve PGE's request to increase the annual amount collected for the Major Storm Cost Accrual from $2.6 million to $3.8 million.

2) Deny PGE's proposed use of a balancing account.

3) Deny PGE's request for deferred accounting and recovery of 2017 Level III storm costs.

Q. What is Staff's reasoning regarding the proposed increase in rates for the Major Storm Accrual?

A. Staff agrees it is appropriate to increase the amount collected annually in rates to reflect an updated rolling 10-year average. In calculating the 10-year average, the $11.4 million in costs incurred in 2017 represents below three standard deviations from the normal range of incurred costs in the years 2008-2017. (3 SDV - $11.75 million). Therefore, I believe the amount requested in rates is appropriate, as it reflects the 10-year average of actual costs, escalated to present value.

Q. Please explain Staff's reasoning regarding the proposed balancing account.

A. The proposal to establish a balancing account to track Level III storm-related costs and revenues is designed to ensure that PGE would recover all storm-related costs on a dollar for dollar basis. Predicting and planning for future weather patterns is not an exact science, and it presents some measure of risk to a wide range of industries. As a matter of general policy, Staff does not believe that weather-related risk should rest entirely on the shoulders of ratepayers. In addition, the Commission has previously reasoned that stochastic risks that are modeled in rates represent reasonable risk that the Company assumes as part of the normal course of utility operations.[7]

Q. Explain Staff's reasoning regarding PGE's deferral of 2017 storm costs.

A. Deferred accounting under ORS 757.259 is ratemaking on a retroactive basis. It allows utilities to recover in future rates costs that were incurred in the past. Normal ratemaking is prospective in that rates are determined based on a forecast of prudent and reasonable costs. Setting rates on a forward-looking basis, the Company is thereby incented to control and manage costs. It also presumes, or attempts to replicate, a reasonable level of risk that any business would face in the normal course of operation.

By setting rates based on past costs, deferred accounting essentially shifts all risk away from investors and onto ratepayers. As such, the Commission has determined that deferred accounting is considered appropriate in circumstances involving events that are not anticipated or predictable, and/or in circumstances in which the events have a substantial financial impact on the utility.[8] Consistent with the Commission's previous decisions regarding deferred accounting, Staff recommends that PGE's application for deferred accounting for the 2017 Level III storm costs be denied.

[7] See Order No. 04-108, p. 9.
[8] See e.g., Order No. 05-1070, Order No. 04-108, p. 9.

PGE actually collects amounts in rates each year for Level III storm costs, so the storm costs are projected and accounted for in rates. Accordingly, the financial impact must be "substantial" to warrant deferred accounting.

While the Commission has not set a precise numerical criteria in defining a threshold level of risk for deferrals, it has concluded that excess net variable power costs (NVPC) that were equal to or less than 250 basis points of the utility's return on equity was an amount that is reasonably absorbed by an electric utility between rate cases.[9] Although the threshold for deferral of storm costs may not be as large as what is appropriate for deferral of NVPC, the 2017 storm costs represent an amount equal to approximately 47 basis points of PGE's authorized ROE. This is well below what the Commission has indicated represents reasonable risk for utilities between rate cases.

Staff concludes the costs PGE incurred in 2017 are part of the risk that the Company can be expected to assume in the normal course of business, just as any for-profit company assumes a certain level of risk, and works to mitigate that risk.

Q. Please summarize Staff's reasoning regarding the proposed balancing account and deferral.

A. If the Commission were to adopt PGE's proposal and allow PGE to continue collecting an amount in rates based on the previous 10-year average, while

[9] See Order No. 04-108, p. 9 Order No. 04-108, p. 9 ("In UM 995, for instance, we established a deadband around PacifiCorp's baseline of 250 basis points of return on equity. We allowed no recovery of costs or refunds to customers within that deadband, reasoning that the band represented risks assumed, or rewards gained, in the court of the utility business.").

assuring full recovery either through a balancing account mechanism or deferral, it would shift the entire risk of weather-related events onto ratepayers. In addition, having a policy that guarantees full recovery of storm-related costs provides no incentive for PGE to prudently manage those costs.

ISSUE 2. DEMAND RESPONSE PILOT PROGRAM

Q. Please summarize this issue.

A. PGE includes approximately $2.4 million in 2019 test year forecast for its Flex Pricing demand response pilot program. In conversations with the Company, PGE explained that at the time of preparing the rate case filing, the Company thought this program was ready to transition from a pilot to a regular program.[10] After further consideration, PGE said that it determined that there were still significant uncertainties and variations in the results to be able to transition to a regular program. As a result, PGE has included costs for the Flex Pricing program in a deferral that it filed with the Commission on May 4, 2018, in Docket No. UM 1708. Staff agrees that PGE should remove these costs from the test year revenue requirement. Therefore, Staff has proposed an adjustment of ($2.4) million to the 2019 test year expense.

Q. Does this conclude your testimony?

A. Yes.

[10] PGE/900, Sthasis-Dillon/6.

CASE: UE 335
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualification Statement

June 6, 2018

WITNESS QUALIFICATIONS STATEMENT

NAME:	Mitchell Moore
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem Oregon 97301-3612
EDUCATION:	Bachelor of Arts, Journalism and Political Science University of Hawaii at Manoa (1992)
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division. My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints. Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UE 335
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

June 6, 2018

UE 335 Staff Exhibit 702
Mitchell Moore

Calculation of impact of 2017 storm damage restoration on ROE

Actuals

net income						
297,471,000						
Total avg. rate base	ROR	0.0627				
4,745,226,000	ROE	0.0716	7.16%			
Storm expense adj.						
(11,400,000)					0.0716	
					0.0763	0.0047 xcheck
Adj net income	Adj ROR	0.0651				
308,871,000	Adj ROE	0.0763	7.63%	0.0047	**47 basis points**	

Regulated Utility

net income						
297,666,000						
Total avg. rate base	ROR	0.0627				
4,745,214,000	ROE	0.0717	7.17%			
Storm expense adj.						
(11,400,000)					0.0717	
					0.0764	0.0047 xcheck
Adj net income	Adj ROR	0.0651				
309,066,000	Adj ROE	0.0764	7.64%	0.0047	**47 basis points**	

Type 1 adjustments

net income						
307,142,000						
Total avg. rate base	ROR	0.0665				
4,621,446,000	ROE	0.0790	7.90%			
Storm expense adj.						
(11,400,000)					0.0838	
					0.079	0.0048 xcheck
Adj net income	Adj ROR	0.0689				
318,542,000	Adj ROE	0.0838	8.38%	0.0048	**48 basis points**	

Formula - ROR (%):	**Net income / Total avg. rate base**	47
Formula - ROE (%):	**(ROR - LT Debt Weighted Cost %) / Common Equity %**	
Formula - Adj. ROR (%):	**Adj. net income / Total avg. rate base**	
Formula - Adj. ROE (%):	**(Adj. ROR - LT Debt Weighted Cost) / Common Equity %**	

CASE: UE 335
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

REDACTED
June 6, 2018

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

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

Q. Please describe your educational background and work experience.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide analysis and recommendations related to PGE's revenue forecast, expense forecast, rate base forecast, and miscellaneous tariff changes.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared:

Exhibit Staff/801 Non-confidential Data Responses
Exhibit Staff/802 Confidential Data Responses
Exhibit Staff/803 Other Revenue
Exhibit Staff/804 Weather Risk Statistical Test
Exhibit Staff/805 Confidential PGE Plant Forecast
Exhibit Staff/806 Excerpt from PGE Advice 02-17

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. MISCELLANEOUS REVENUE

Q. Please summarize this issue.

A. Revenue forecasting is a critical component of a rate case. If a utility is earning sufficient revenue at current rates to cover the firm's revenue requirement, there may be no need to change rates.

FERC accounting rules classifies revenue into several different components:

- Retail Sales (accounts 440-446);
- Sales to other entities intended for resale (account 447 for electric utilities);
- Intracompany transfers (account 448 for electric utilities); and
- Other operating revenues, including miscellaneous service revenues, rents and revenues from the use of transmission and other facilities (accounts 450-456 for electric utilities).

In this testimony, I evaluate the test year revenues for "other operating revenues," or the final bullet above. Staff addresses the first two items in other testimony, and the third item does not affect revenue requirement as intracompany transfers net to zero.

PGE proposes test year other revenues of $25.4 million. PGE states that the primary sources of other revenue are rent of electric property, transmission revenue, joint-pole revenue, steam sales revenue, and ancillary service revenue.[1] PGE arrives at its forecast by using historic revenues to

[1] PGE/200, Tooman-Espinoza/6.

forecast 2019 revenues, and making pro-forma adjustments to for deferred items, transmission sales to electric service suppliers (ESS) that sell energy directly to customers in PacifiCorp's service territory, Green Power Administration revenue, its affiliate, Salmon Springs Hospitality Group, and wireless pole attachment revenues. Staff disagrees with PGE's proposed adjustments for ESS transmission sales and the pole attachment revenue.

Q. How does PGE adjust ESS transmission sales?

A. PGE forecasts reduced direct access load and reduced Open Access Transmission Rates. Based on this PGE reduces transmission sales by $355,000 relative to 2017 actuals.[2]

Q. What is Staff's concern with this approach?

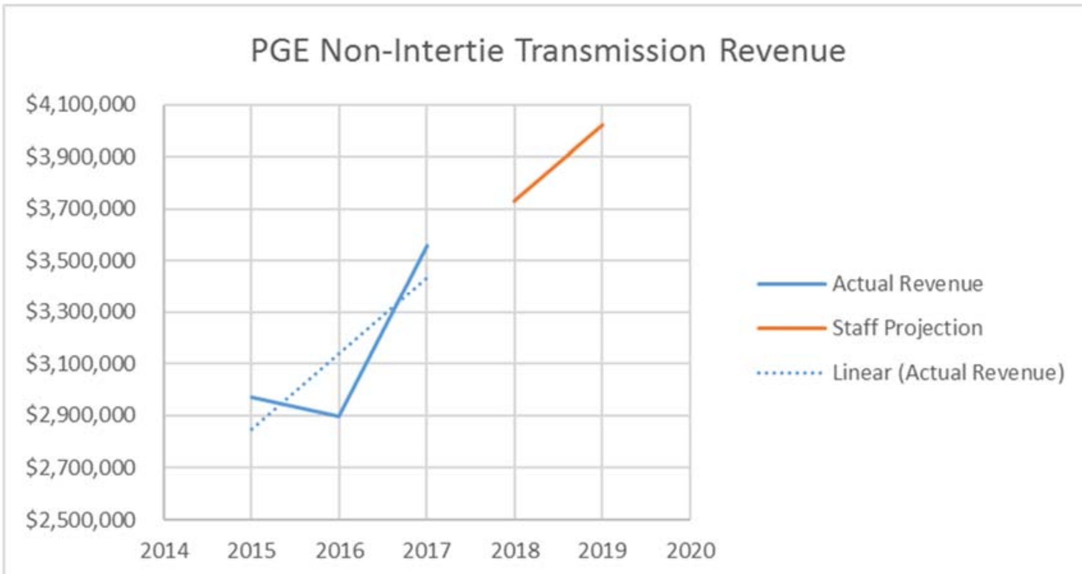
A. Staff is concerned that this approach does not account for the Commission's pending rulemaking for a New Load Direct Access Program, docketed as Docket No. AR 614. Staff anticipates that rulemaking will bring new direct access load to Oregon. Because ESSs that sell electricity to customers in PacifiCorp's service territory must compensate PacifiCorp for use of PacifiCorp's distribution system, increased direct access load will mean increased transmission revenue.

Q. What is Staff's proposal for transmission sales?

A. Staff proposes an alternative forecast that projects historic actual transmission revenues using three years of actual data. This results in an increase of transmission revenues by $464,000 relative to 2017 actuals, and an increase

[2] Staff/803.

of $819,000 relative to PGE's filed test year revenue.[3] This approach is reasonable because it incorporates expected load growth associated with Docket No. AR 614.



Q. How does PGE adjust pole attachment revenue?

A. PGE reduced pole attachment revenue by $1.2 million to reflect a decrease in wireless pole attachment rental rates. PGE did not provide the calculations for this decrease in revenue in work papers and therefore Staff has been unable to confirm how PGE calculated this decrease in revenue. Staff also observes that PGE's previous forecast of decreased pole revenue from Docket No. UE 319 was higher than actual. Because PGE has not supported the reduction to pole attachment revenue, Staff recommends excluding this adjustment. This results in an increase of $1.2 million to pole revenue relative to PGE's filed test year revenue.

[3] Staff/803, Kaufman/1.

Q. Please summarize Staff's other revenue adjustment.

A. Staff recommends increasing other revenue by $2,022,596.

ISSUE 2. COST ALLOCATIONS AND AFFILIATED INTEREST TRANSACTIONS

Q. Please summarize this issue.

A. As part of Docket No. UE 319, PGE agreed to hold an allocation workshop to provide additional details on PGE's cost allocations and affiliated interest transactions. The detail provided at this workshop clarified many aspects of PGE's cost allocation process. Staff requested that PGE update the filed cost allocation manual to include the level of detail provided at the workshop. PGE filed an updated cost allocation manual on May 30, 2018. Staff has reviewed the manual and confirmed that it includes additional detail on PGE's cost allocation process. Unfortunately, the delay in providing this update did not provide sufficient time for a thorough review of the new manual. Staff's preliminary review raises a concern that some services are provided to affiliates and non-utility entities at cost, rather than at the higher of cost or market.

Q. Please provide additional detail related to the concern that services may be provided to affiliates at cost.

A. PGE allocates costs to affiliates for services such as information technology and printing, and bills labor at cost. Staff is concerned that when utilities bill labor at cost, they are violating the requirement that goods and services provided to affiliates be priced at the higher of market price or cost.

Q. What policy governs how utilities should bill affiliates?

A. Transfer prices for services between utilities and affiliates are addressed by OAR 860-027-0048(4)(d) and (e):

> (d) When services or supplies are sold by an energy utility to an affiliate, sales shall be recorded in the energy utility's revenue accounts at the approved rate if an applicable rate is on file with the Commission or with FERC. If services or supplies are not sold pursuant to an approved rate, sales shall be recorded in the energy utility's accounts at the energy utility's cost or the market rate, whichever is higher. Approved rates shall be established as appropriate.
>
> (e) When services or supplies (except for generation) are sold to an energy utility by an affiliate, sales shall be recorded in the energy utility's accounts at the approved rate if an applicable rate is on file with the Commission or with FERC. If services or supplies (except for generation) are not sold pursuant to an approved rate, sales shall be recorded in the energy utility's accounts at the affiliate's cost or the market rate, whichever is lower.

Q. How does PGE's cost allocation manual align with OAR 860-027-0048(4)(d)?

A. PGE's cost allocation manual identifies a method of calculating the cost of shared services provided to affiliates and non-utility operations. The manual further states that affiliates are billed for allocated costs. This suggests that PGE does not evaluate the market value of services provided to affiliates. If this is the case, PGE's cost allocation manual is not consistent with OAR 860-027-0048(4)(d). Utilities should establish market rates for services provided to affiliates and bill affiliates at the higher of cost or market. Staff has raised this issue in Northwest Natural's general rate case Docket No. UE 344 as well as in individual affiliated interest filings of other Oregon utilities.

Q. What is your recommendation related to affiliated transactions?

A. Staff recommends that PGE implement one of two practices:

1. Identify market rates for services provided to affiliates, or
2. Include a "profit" adder for cost based charges to affiliates.

Q. Please explain Staff's second alternative for a profit adder.

A. Staff's alternative is to simulate a market price by including a profit adder in the allocated cost that PGE calculates for affiliate services. This approach reproduces a market rate without requiring PGE to assume the administrative burden associated with identifying a market rate for all services provided to affiliates. This approach also prevents utility customers from subsidizing services provided by utilities to affiliates or unregulated operations.

ISSUE 3. ELECTRIC PLANT ACQUISITION ADJUSTMENTS

Q. What is an electric plant acquisition adjustment?

A. When a utility purchases used plant the utility could purchase the plant above or below the depreciated value. For example, PGE may purchase power poles that are already placed in service from PacifiCorp. Suppose hypothetically PacifiCorp already fully depreciated this plant. This means that the original investment has already been fully recovered. If PGE purchased the poles at a cost that exceeded the depreciated value, and included the full purchase price in rates, the investment would be double recovered, once by PacifiCorp customers and once by PGE customers. FERC requires that utilities maintain an electric plant acquisition adjustment account that records the difference between purchase price and the depreciated value of the plant when it was purchased. This account reduces rate base and is not included rates.

Q. What did Staff investigate related to this issue?

A. Staff investigated whether PGE accurately recorded electric plant acquisition adjustments. Staff found that PGE has not acquired any plant that is subject to an acquisition adjustment.

Q. What is Staff's recommendation related to this issue?

A. Staff recommends that this issue continue to be monitored in future rate cases. Staff makes no proposals for this issue relevant to the current case.

ISSUE 4. REVENUE DECOUPLING

Q. What is a revenue decoupling mechanism?

A. A revenue decoupling mechanism is a mechanism that reduces the relationship between sales and revenue. Revenue is calculated as Price times Quantity:

$$Revenue = Price * Quantity$$

Absent a decoupling mechanism, when quantity increases revenue increases. A revenue decoupling mechanism is a pricing mechanism that adjusts price in response to changes in quantity in order to achieve a target revenue.

For example consider a case where a general rate case revenue requirement is $50,000. If forecasted sales are 1,000 units the price would be set at $50. If actual sales are higher than forecasted, the company would collect more than $50,000. For example, if actual sales were 1,250, the company would receive $62,500. One type of decoupling mechanism would modify the price charged prior to billing customers. In this case, the price would be lowered from $50 to $40, and the company would receive the rate case revenue requirement of $50,000. An alternative approach is to maintain the $50 price in bills and collect $62,500 from customers, but defer the excess revenues of $12,500 for return to customers at a later date. There are many variants of decoupling that all perform the similar basic function of returning revenues to some normalized level.

Q. What is the purpose of decoupling mechanisms?

A. Decoupling mechanisms remove or reduce the relationship between sales volume and revenue. A large portion of a utility's annual expense is fixed with respect to sales. This means that a utility's costs do not increase proportionally to sales. In the example from above, consider a firm that has fixed costs of $35,000, a fair profit level of $5,000 and variable per unit cost of $10. If the firm sells 1,000 units the total cost, including the allowance for profit, is $50,000. If the firm sells 1,250 units the firms total cost including a profit allowance increases to $52,500. As noted without a decoupling mechanism the firm would earn $15,000, or three times the fair profit level.[4]

Without decoupling, the firm has a direct incentive to increase sales because it increases profit. This incentive to increase sales is in direct conflict with least cost planning results which often select energy efficiency as cost effective solutions to meeting customer energy needs.

Q. The previous example seems to benefit customers rather than utilities. Why do utilities support decoupling mechanisms?

A. Utilities support decoupling mechanisms because the mechanisms function in the opposite direction when sales decrease. When sales are lower than expected, utilities are able to collect more per unit sold to make up the lost revenue. This trade-off is acceptable to utilities because it represents a reduction to the utility's risk profile.

Q. What affect does decoupling have on the risk profile of utilities?

[4] Calculated as $62,500 - $35,000 – ($10 * 1,250).

A. Decoupling mechanisms reduce the volatility of utility earnings. Earnings are more consistent with a decoupling mechanism than without a decoupling mechanism. This reduction in volatility represents a reduction in risk to utilities.

Q. What affect does decoupling have on the risk profile of customers?

A. The impact of decoupling on customer risk is less clear, and depends on the year to year correlation of variables that impact customer revenue. In theory, exposure to risk increases.

Q. What is the difference between a full and partial decoupling mechanism?

A. A full decoupling mechanism adjusts revenues for all deviations from forecasted revenue, regardless of the factor causing the deviation. A partial decoupling mechanism only adjusts for usage variation caused by specific factors, such as energy efficiency. Partial decoupling mechanisms are used when policy makers want to target specific causes of use variation. For example in Oregon the Commission has historically used decoupling mechanisms that target sales variations caused by energy efficiency.

This approach is reasonable because it holds energy utilities harmless while advancing state energy policies and minimizing customer rates. It also avoids transferring risk from utility shareholders to utility customers.

Q. What is PGE's proposal in this docket?

A. PGE proposes three changes to the current PGE decoupling mechanisms:[5]

[5] PGE presents these as four changes, however eliminating the LRRA and adding the SNA as a replacement is really only one change.

1. Convert large customers from energy efficiency decoupling to full decoupling;
2. Convert small customers from non-weather partial decoupling to full decoupling;
3. Make the rate-change-mitigation cap excess balances carry forward.

Q. Why does PGE propose to convert large customers from energy efficiency decoupling to full decoupling?

A. PGE proposes to convert large customers from energy efficiency decoupling to full decoupling because it claims that this is a regional trend. Northwest Natural has made a similar request in Docket No. UG 344, and Staff has opposed Northwest Natural's proposal. At this time, Staff finds that it is premature to claim that full decoupling for large customers is a regional trend.

PGE also claims that converting from an energy efficiency decoupling mechanism to a full decompiling mechanism PGE will be able to make filings a few months earlier. Neither of these arguments indicates that benefits exist for ratepayers.

Q. Why does Staff oppose PGE's proposal?

A. Staff opposes PGE's proposal because it constitutes a shift of risk from PGE shareholders to PGE ratepayers with no offsetting customer benefit. PGE's proposal eliminates large customers' ability to mitigate economic risk by reducing electric use. Under PGE's proposal, reduced electric use caused by poor business environments would result in increased electric prices.

Q. Why does PGE propose to convert small customers from non-weather partial decoupling to full decoupling?

A. PGE claims that the current weather normalization process burdens customers with weather related risk. PGE provides no evidence in support of the claim.[6] PGE points to a table that calculates the standard error of bills with and without full decoupling.[7] The table shows that there is no statistically significant difference in weather risk with and without weather decoupling.

Q. Why does Staff oppose full decoupling for small customers?

A. Staff opposes full decoupling because it provides no benefit to customers and it does not further any Commission policy goals.

Q. Why does PGE propose to make the rate-change-mitigation cap excess balances carry forward?

A. PGE does not provide an explanation for why the excess balances should carry forward.

Q. Why does Staff oppose allowing the excess balances to carry forward?

A. The rate change mitigation cap is a protection in place for customers to reduce the negative effects of the current partial decoupling mechanism. Allowing the balances to carry forward will harm customers. PGE has not identified any rational to support this harm to customers.

Q. What is your recommendation regarding this issue?

[6] Staff/804 provides the results of a statistical analysis of bill variance with and without weather decoupling. There is no statistically significant variation in variance, which is a measure of risk.
[7] PGE/1306 Macfarlane-Goodspeed/32.

A. Staff recommends maintaining the current decoupling mechanisms with no change other than routine parameter updates.

ISSUE 5. IT SPENDING

Q. Please summarize this issue.

A. PGE forecasts a 40 percent increase in IT spending from 2017 to 2019.[8] PGE's testimony highlights increased hardware and software maintenance costs, the Network Resiliency Project, on-going cyber security efforts, and a movement of labor dollars from capital to O&M as the primary drivers. Staff does not agree that these drivers justify a 40 percent increase in IT spending.

PGE already spends **[Begin Confidential]** [redacted] **[End Confidential]** Staff recommends that PGE control IT costs and improve IT management to bring PGE IT spending in line with peers.

Q. How does PGE's information technology department compare to peers?

A. PGE's IT spending is **[Begin Confidential]** [redacted] **[End Confidential]** its peers' IT spending. In 2015, PGE engaged a third party to evaluate PGE's IT spending. The resulting report found that compared to investor owned firms of similar size PGE spent: **[Begin Confidential]**

[redacted]

- [redacted]

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[8] PGE/600, Buttress/3.
[9] Staff/802, Kaufman/7.
[10] Staff/802, Kaufman/7.

[redacted].[12] **[End Confidential]**

Q. Please address the increase in hardware and software maintenance.

A. PGE credits the implementation of the 2020 Vision program as driving up the maintenance costs of hardware and software. PGE characterized the 2020 Vision initiative as making PGE more cost-effective.[13] Staff is concerned that PGE is including cost increases related to the 2020 Vision, but failing to account for the cost-efficiencies of the initiative. This means that either the business case supporting the 2020 Vision program was not accurate, and the program was not cost-effective, or that there will be efficiencies associated with the system, but these efficiencies are not being included in rates. As a result, customers will be paying higher costs without receiving the benefits of the forecasted efficiencies.

Q. Please address PGE's Network Resiliency Project

A. PGE's testimony identifies the network resiliency project as a project that will allow PGE to continue to operate applications to customers in the event of a hardware failure. However, the applications that PGE points to are non-critical applications that may not warrant the investment in network resiliency, such as interactive voice response and web payment. For example, if a hardware

[11] Staff/802, Kaufman/9.
[12] Staff/802, Kaufman/9.
[13] Docket No. UE 215, PGE/100, Piro/10; Docket No. UE 262 PGE/900, Stathis-Dillin/12.

failure prevents customers from making web payments, customers can mail a payment or wait for network systems to begin functioning again. It is unnecessary to invest in network resiliency for non-critical applications.

Q. Please address PGE's cyber security efforts.

A. Staff reviewed a third party report addressing PGE's cyber security.[14] Staff also performed an on-site review of PGE's cybersecurity efforts and interviewed PGE's cyber security director. Staff found that PGE has recently increased cyber security efforts and has a concrete plan to continue security improvements. However, Staff is generally concerned that PGE's rapid escalation of security spending and effort may result in some inefficiencies, and may result in test year expenses that are not normal.

Q. Why are you concerned that PGE's test year expenses may not be normal?

A. PGE has **[Begin Confidential]** [redacted] **[End Confidential]** This contributed to PGE's 40 percent increase in IT spending from 2017 to 2019.[16] Because this is a short-term initiative the expense involved is not representative of a normal year.

Q. Please address the issue of labor dollars moving from capital to O&M.

A. PGE's recent IT programs have resulted in a large increase in IT FTEs over the last 10 years. PGE's IT capital spend is now reduced; however, this is not

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[14] PGE's response to OPUC DR 274, not produced in this testimony to maintain PGE security.
[15] Staff interview of PGE Security Director.
[16] PGE/600, Buttress/3.

translating into fewer IT FTEs. Instead, PGE appears to be transferring FTE from capital projects to O&M. PGE will not achieve the 2020 Vision efficiencies if it maintains the FTE ramp up that the 2020 Vision caused.

Q. Does PGE have a plan in place to control its recent IT cost increases?

A. PGE did not provide Staff with a plan to control the growth of its IT spending. Staff asked PGE to provide all recent studies of its IT department. PGE provided a benchmark study comparing PGE's IT spending to other utilities.[17] This study, combined with PGE's requested 40 percent increase in IT O&M, indicates that PGE is experiencing runaway IT costs. PGE did not provide Staff with documentation of how it plans to control these costs going forward.

Q. What do you recommend related to IT O&M costs?

A. Staff recommends that PGE develop and provide parties with a plan to bring IT spending in line with its investor-owned utility peers. Staff also recommends applying the nine year average growth rate in IT O&M to 2017 actuals when calculating the test year IT spending.[18] From 2008 to 2017, PGE's O&M increased an average of seven percent per year. If this same rate is applied to PGE's most recent year of actual IT O&M Expense, PGE's test year IT expense would be $84.7 million, an expense reduction of $18.1 million. Staff therefore recommends a reduction to test year expense of ($18.1) million.

Q. Why is your recommendation reasonable?

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[17] Staff.802, Kaufman/4 to 18.
[18] Staff selected nine years due to data availability from PGE testimony in Docket No. UE 262. Staff is also willing to consider a 10 year growth average. Staff does not support a shorter average due to concern that recent growth in IT spending may not reflect well managed IT cost growth.

A. My recommendation is reasonable because it adjusts PGE's IT spending to be more in line with PGE's peers, while recognizing that an increase in IT spending may be necessary in the short term to achieve the long term goal of transitioning of industry standard IT spending. My adjustment also accounts for the claimed efficiencies of the 2020 project which has already added a substantial amount of capital to PGE's rate base.[19] This approach will give PGE additional time to determine why its IT spending has increased significantly and to find ways of better managing PGE's IT growth.

[19] Docket No. UE 215, PGE/100, Piro/10; Docket No. UE 262 PGE/900, Stathis-Dillin/12.

ISSUE 6. CUSTOMER ENGAGEMENT TRANSFORMATION

Q. Please summarize this issue.

A. The Customer Engagement Transformation program is a collection of projects designed to **[Begin Confidential]** [redacted][20] **[End Confidential]** Staff is concerned that by seeking to **[Begin Confidential]** [redacted] **[End Confidential]** PGE may have incurred more costs than necessary to provide safe and reliable service. While the CET program included many projects, two projects provided the cornerstones of this program: a customer information system (CIS) and a meter data management system (MDMS).

Q. Please outline your testimony on this issue

A. This issue has the following elements:

1. PGE's communication with the Commission regarding CET costs.
    a. PGE did not inform the Commission of cost increases in a timely manner.
2. The Scope of the CET program.
    a. The CET program included too many objectives and included objectives that may not provide value to ratepayers.
3. PGE's analysis of the CET program.
    a. PGE failed to perform cost-benefit analysis of the CET program.
    b. PGE did not consider alternatives that included reduced program scope.

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[20] PGE/901C, Stathis- Dillin/4.

4. Cost of the CET program.
    a. CET program includes costs that are not appropriate for customer rates.
    b. CET program costs contain an excessive amount of high priced consulting costs.
5. Staff recommendation regarding CET
    a. Staff recommends that the Touchpoint portion of CET capital costs be allowed into rates at the upper range of the originally forecasted cost. This amount is $66 million.

PGE's Communication with the Commission regarding CET Costs

Q. Please summarize how CET cost was presented to Staff and the Commission over time.

A. Certain components of the CET program appear to have changed over time. A more consistent tracker is the cost of the two main components, the CIS and MDMS, which PGE calls "Touchpoints." Touchpoints was identified in PGE's 2013 rate case as costing $57 to 66 million in capital for full implementation.[21] This cost increased to $99.3 million in October 2014.[22] However, PGE's 2015 rate case testimony does not identify the large increase in Touchpoint costs. Instead, PGE indicated that PGE made minor adjustments "with minimal impact on costs."[23] The Touchpoint cost forecast increased to $136 million in

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[21] PGE/900 Stathis – Dillin/22.
[22] PGE/900 Stathis – Dillin/22.
[23] Docket No. UE 294 PGE/900 Stathis – Dillin/12.

June 2015.[24] PGE does not seem to have notified the Commission of substantial changes from the initial $57 million estimate until 2017, when PGE filed testimony indicating the capital costs were projected to be $140 million. [25] PGE currently expects the project capital costs to be $147.5 million.[26]

Q. What would have been the appropriate time to notify the Commission of the cost increase?

A. Given PGE's decision to include CET O&M costs in its general rate cases Docket Nos. UE 262, UE 283, UE 294, and UE 319, PGE should have updated the Commission on current cost expectations in each of these proceedings. PGE's February 2015 testimony in Docket No. UE 294 highlights a small delay in the timeline of the CET project, but the testimony fails to note that capital costs had increased from $66 million to $99 million. Sometime during the first half of 2015, PGE became aware that costs had increased to $140 million. PGE could have notified the Commission of this second cost increase in its July 20, 2015 Reply Testimony. PGE did not inform the substantial cost increases until February 2017 in Docket No. UE 319.

Q. What was Staff's response in UE 319 to the Touchpoints cost increase?

A. When Staff became aware of the substantial cost increases in UE 319, Staff noted that the additional costs appeared to be driven by PGE's effort to integrate the Touchpoints programs with PGE's other applications. Staff noted

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[24] Staff/802, Kaufman/41 OPUC DR 273 Attached Presentation dated June 28.
[25] Docket No. UE 319 PGE/900 Stathis – Dillin/13.
[26] PGE/900 Stathis – Dillin/25

that the additional cost did not appear to be supported by ratepayer benefits.[27] Staff recommended that the O&M cost deferral for CET be limited to the initially forecasted O&M costs.[28] Staff also recommended that PGE supply supporting information when PGE requests incorporating Touchpoints capital into customer rates.[29]

Q. What was PGE's cost estimate when developing the business case for the Touchpoints projects?

A. There is some discrepancy between PGE documents and PGE testimony. The business case initiating the Touchpoints project forecasted capital costs between **[Begin Confidential]** [redacted].[30]**[End Confidential]** This discrepancy is important because the business case is the initial document that justifies the expense of the project. When PGE initially conceived of the Touchpoints project, and evaluated the case for implementing the project, PGE anticipated that the capital costs could be as low as **[Begin Confidential]** [redacted] **[End Confidential]** project is not sufficient to support a $147.5 million project.

[27] Docket No. UE 319, Staff/1100, Moore/11.
[28] Docket No. UE 319, Staff/1100, Moore/12.
[29] Docket No. UE 319, Staff/1100, Moore/11.
[30] Staff/802, Kaufman/20 and 23, PGE Response to OPUC DR 270.

Q. PGE describes the cone of uncertainty with respect to estimating project costs.[31] Can you explain how PGE should have applied this concept to the Touchpoints project?

A. PGE should have used the cone of uncertainty to inform stakeholders about the uncertainty of the project costs in the early phases of the project. **[Begin Confidential]** [redacted] **[End Confidential]**

Q. How did PGE present the uncertainty related to the Touchpoints projects to the Commission?

A. PGE appears to be calling the 2013 estimates the "initial concept" estimate.[33] If that is the case, the project should have been presented as a concept, not a definite project that had been approved. PGE also should have presented the project cost as being highly uncertain, with a range of nearly 5 times the expected cost. Instead PGE provided a cost range of $57 to $66 million.[34] This cost range is more consistent with the "Detailed Design Complete" phase in the cone of uncertainty.

Scope of the CET program

Q. What was the scope of the CET program?

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[31] PGE/903, Stathis-Dillin/1.
[32] Staff/802, Kaufman/20 and 23, PGE Response to OPUC DR 270.
[33] PGE/903, Stathis-Dillin/1.
[34] PGE/900, Stathis – Dillin/22.

A. The CET program consisted of 24 projects.[35] The CIS project alone had **[Begin Confidential]** [redacted] **[End Confidential]** business requirements.[36] A major source of complexity for the CET program was the integration of the MDMS and CIS with PGE's other programs and databases, such as web portals and customer marketing databases.[37]

Q. Did PGE reduce the scope of the program in light of higher costs?

A. PGE does not appear to have reduced the scope of the program.

Q. Why is the complexity of scope important?

A. There is a direct relationship between the complexity of projects and the success of projects. Small IT projects are 10 times more likely to be successful than large projects.[38] One criteria of a successful project is delivering the project within the budget.

PGE's Analysis of the CET Program

Q. What type of analysis did PGE initially perform for the CET program?

A. The business cases for the CET program compare the financial costs and benefits; however, this comparison does not appear to include a net present value analysis, internal rate of return analysis, or other common financial analysis tools. PGE indicated in Docket No. UE 262 that it expected incurred capital cost of $70-80 million for the program (this amount includes Touchpoints as well as other CET capital projects), $22-25 million in

[35] UE 319 - PGE/900, Stathis-Dillin/7.
[36]PGE/901C Stathis – Dillin/31.
[37] Staff interview with CET Director David Worth.
[38] Standish Group 2015 Chaos Report accessed June 6, 2018
https://www.infoq.com/articles/standish-chaos-2015

development O&M, and $4-6 million in annual ongoing net cost reductions (i.e. O&M reductions offset by operating costs).[39] Based on these values alone, the program does not appear to pencil out. Assuming a 10 year life, the lifetime O&M reductions in nominal terms amounts to at most $60 million, which is not enough to cover the initial investment, let alone capital carrying costs or the final escalated cost forecast.

Q. What type of analysis did PGE perform after determining the actual cost of the project would be closer to [Begin Confidential] [redacted][40] [End Confidential]

A. A presentation to the PGE finance committee presenting the updated costs contains no **[Begin Confidential]** [redacted] **[End Confidential]** of the project.[41]

Q. Did PGE consider the cost of other vendors besides Oracle?

A. No, PGE does not appear to have considered any other vendors besides Oracle. PGE claims that Oracle was the **[Begin Confidential]** [redacted].[42] **[End Confidential]** PGE should have evaluated the costs of the other vendor options to identify the tradeoff between achieving its IT strategy and incurring higher costs.

CET Program Expenditures

Q. Please summarize Staff's review of the costs of the CET program.

[39] Docket No. UE 262, PGE/900, Stathis – Dillin/12.
[40] Staff/802 PGE Response to OPUC DR 273.
[41] Staff/802 PGE Response to OPUC DR 273.
[42] PGE/901 Stathis – Dillin/7.

A. Staff requested the program budget and invoices. PGE provided high level budgets provided to the Steering Committee and a spreadsheet summarizing invoices.[43] Staff identified a **[Begin Confidential]** [redacted].[44] **[End Confidential]**

Staff Recommendation

Q. What is Staff's recommendation regarding the CET Program?

A. Staff recommends that the capital included in rates be limited to the high end of the initial capital forecast. Staff makes this recommendation because PGE has failed to demonstrate that the funds PGE deems necessary to achieve its desired class customer service are necessary for the provision of safe and reliable electric service. Although some customers may appreciate more "bells and whistles" when interacting with their utility, these are not necessary to the provision of safe and reliable service, and would come at a great cost to all PGE customers. Also, PGE should have performed a more thorough cost-benefit analysis and alternatives analysis at each stage that the project costs substantially increased.

Q. What is the rate base impact of your adjustment?

A. PGE has forecasted a final cost of $147.5 million for Touchpoints in rate base.[45] The original capital cost presented to the Commission for the Touchpoints component of CET was $66 million. From the evidence provided so far, Staff is not convinced that the deviation from the original CET cost

[43] Staff/802 PGE Response to OPUC DR 270.
[44] Staff/802 PGE Response to OPUC DR 270.
[45] PGE/902. Stathis-Dillin/1.

projection is justified, nor does Staff understand the how the cost increase will provide incremental benefit to ratepayers. Thus, unless the Company can provide convincing evidence justifying the cost increase, Staff's recommendation is a reduction of ($81.5) million.

ISSUE 7. CARTY PLANT

Q. Please summarize this issue.

A. In Docket No. UE 319 PGE agreed to limit the gross Carty Plant in rate base to $514 million. Staff investigated whether trailing plant investments at Carty have been included in rate base. Staff reviewed Carty plant accounts as well as plant that may be related to Carty. Staff found no indication that PGE has included more than $514 million in (gross plant) rate base associated with Carty Plant.

ISSUE 8. PLANT IN SERVICE

Q. Please explain the relevance of plant in service in the context of a general rate case.

A. A utility's revenue requirement is expressed in the following equation: R = E + (v-d)r, where "R" is the revenue requirement; "E" is the utility's expenses, including depreciation expense; "v" is the gross value of the utility's property; "d" is the accumulated depreciation of utility property; and finally, "r" is the utility's authorized rate of return on rate base. Plant in service is the capitalized amount of plant investments "in-service" as measured a particular point in time for ratemaking purposes. "Plant in service" generally constitutes the vast majority of rate base. Plant is considered "in service" if it is used and useful for providing the utility's regulated services. Utilities close capital investments to plant in service accounts regularly throughout the year. "Net plant in service" is plant in service less accumulated depreciation.

Q. What is PGE's proposed net plant in service?

A. PGE proposes to use year-end 2018 plant in service as the basis for calculating plant in service in base rates in this case. PGE forecasts 2018 year end net plant in service to be $4,780 million.[46]

Q. How does PGE arrive at this number?

A. PGE begins with year-end 2017 actual net plant in service, and adjusts this value for forecasted capital additions, retirements, and depreciation through December 31, 2018.

[46] PGE/207, Tooman-Espinoza/1.

Q. What are PGE's forecasted capital additions and retirements by month?

A. Staff Exhibit 805 summarizes PGE's forecasted additions and retirements by month for 2018.

Q. How does PGE forecast 2018 capital additions?

A. PGE forecasts 2018 capital spending by funding project.[47] PGE then allocates forecasted project funding to 2018 months and FERC accounts. Staff has requested this allocation map but PGE has not provided it.[48]

Q. What standard does the Commission require for plant to be included in utility rates?

A. Plant must be used and useful for the provision of utility service and the costs must be prudent.[49]

Q. What determines the prudence of a project?

A. A prudence review is used to determine whether the company's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances that then existed.[50] With regard to the prudence standard as it relates to planning and construction, the Commission has stated:

> Prudence in planning and constructing a plant is relevant for determining the valuation of the facility once placed in rate base. If a plant shown to be used and useful was constructed at an unnecessarily high cost, only the cost deemed appropriate rather than actual historical cost would be placed in rate base. In this

[47] Staff/802, Kaufman/1 to 3 identifies 2018 plant additions by funding project.
[48] Staff/801, Kaufman/10.
[49] *In re PacifiCorp*, OPUC Docket No. UE 246, Order No. 12-493 at 2-3 (Dec. 20, 2012).
[50] *Id.* at 25-26.

> review, therefore, we must determine whether [the utility's] actions or decision based on what it knew or should have known at the time, were prudent in light of existing circumstances. This analysis includes a review of not only the company's decision to make an investment, but also to the amount of money it decided to invest. Expenditures found excessive, unaccounted for, or caused by lack of foresight should be deemed imprudent and disallowed.[51]

Q. How does Staff review the prudence of plant investments?

A. Using the standard articulated above, Staff reviews the decision to undertake projects by evaluating the need for the project, analyzing the expected costs and benefits of the project, and evaluating alternatives to fulfilling the project need. Staff may also review the implementation and management of a project by reviewing the project management documents, invoices, and outcomes, and considering those within the context of what a reasonable utility would do.

Q. Has Staff reviewed the proposed projects for 2018 plant additions?

A. Staff requested project documents for all projects forecasted to transfer to plant in 2018. PGE has not provided this information but has agreed to provide the information as projects close throughout 2018.[52] The initial delivery of documents was scheduled for May 31, 2018, but as of June 2, 2018 these documents were not available. Staff will implement the prudence review described in the previous question as these documents become available.

Q. Is it possible to determine prudence of a project prior to the project's in service date?

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[51] *In re Northwest Natural Gas Company,* OPUC Docket No. UG 132, Order No. 99-697 at 52 (Nov. 12, 1999) (citing *In re Portland General Electric*, OPUC Docket Nos. UE 47 & UE 48, Order No. 87-1017 (Sept. 30, 1987).

[52] Staff/801, Kaufman/14 and 15.

A. Staff can only review the decision to undertake the project and projected costs prior to the projects in service date. If actual costs vary from projected costs, Staff is unable to review those variances until after the project is completed.

Q. How has Staff treated forecasted projects in previous rate cases?

A. In previous rate cases, for some projects, Staff has supported forecasted plant additions to be deemed prudent.

Q. Have there been issues with the Commission determining forecasted plant as prudent?

A. Yes, there are two issues with this approach. First, approval of capital budget is not equivalent to the review of the projects that may actually close to plant prior to the rate-effective period. Under this approach, projects may be substituted in and out of the queue based on evolving circumstances within the utility. Because of this, Staff and other parties may not have reviewed for prudence some projects that close to plant—some of which require significant investment. Second, there may be concerns about the implementation or management of a project that is anticipated to close after the record closes in the rate proceeding in which costs are approved for recovery. For example, in Docket No. UE 294 the Commission deemed the Carty Plant to be prudent on a forecast basis, up to the amount stipulated in that case. Several issues in management and completion of the project came to light, which led to cost overruns for the project. These issues may impact the amount of rate base for Carty that is prudently included in rates.

Q. Given the need for Staff and parties to review projects, how can the Commission determine prudence of plant forecasted to be added after the record closes in this proceeding?

A. Parties can review the prudence of PGE's decision to implement specific projects by reviewing the project business case, project charter, project management plan, and other documents used by PGE to support the decision to implement the project. These documents should all be available for 2018 projects because they are necessary inputs to the 2018 plant forecast. Parties can also review actual management of the projects as they are completed. However, there is likely a disconnect between the capital projects that are proposed at the beginning of the case and the capital projects that may close to plant later in the year. This is because PGE uses a centralized project justification system in which yearly spending levels for each project are discussed, but updates the projects that are actually undertaken throughout the year. Therefore, there may be projects that close to plant that have not been reviewed by Staff at all—even on a forecast basis. Additionally, even if a project is known prior to the rate-effective date, Staff and parties have no ability to add information to the record after the hearing regarding the prudence of the decision to undertake the project, or on the prudence of the project's costs.

Staff's last round of testimony is filed August 15, 2018. This is the last opportunity for Staff to provide the Commission with analysis addressing: actual plant dollars, conformance to project plans, and appropriateness of spending for rates. Given this limitation, the Commission should not make prudence decisions regarding capital projects closing to plant on or after August 1, 2018.

Q. What adjustments do you propose given the timing of when project documents become available?

A. Staff asked for but has not been given access to any project documents related to any plant brought in service in 2018.[53] This means that Staff cannot comment on the prudence of implementing any projects forecasted to be added in 2018. Because PGE has agreed to provide data updates as projects are completed, Staff anticipates reviewing projects that are placed in service prior to August 1, 2018. In this round of testimony Staff makes no adjustments to PGE's forecasted plant additions through August 2018. However, Staff does recommend removing all plant additions forecasted for after August 1, 2018. This results in a reduction to rate base of ($224.9) million.[54]

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[53] With the exception of CET related projects, which are addressed in a separate section of this testimony.

[54] This figure does not account for accumulated depreciation or other items that need to be adjusted as a result of removing plant from rate base. This figure is also net of retirements after August 1 2018. Staff is continuing to investigate how PGE forecasts retirements and whether the staff adjustment should be net of retirements. If retirements are excluded Staff's adjustment would increase by $40 million. Staff recommends that PGE calculate these miscellaneous adjustments as part of PGE's compliance filing for the Commission's decisions on this issue.

ISSUE 9. LONG TERM DIRECT ACCESS

Q. What is long term direct access?

A. Direct access is a type of service available to non-residential customers that allows participants to purchase generation and transmission services in an open market while continuing to receive distribution services from their incumbent utility. Customers electing direct access service pay a distribution rate to the incumbent electric utility that mirrors the equivalent cost of service schedule, but excludes generation and transmission costs. Customers receiving direct access service receive energy from an Electric Service Supplier (ESS).[55]

Customers receiving direct access service also pay or receive transition adjustments for a specific period of time. Transition adjustments are a means to transfer the costs and benefits of direct access. If direct access results in a benefit for cost-of-service (COS) customers, a transition credit can transfer some or all of that benefit to direct access customers. If direct access results in a cost for COS customers, a transition charge can transfer some or all of that cost to direct access customers.

Long term direct access is a direct access service that requires participants to opt-out of cost of service eligibility. This means that long term direct access participants cannot receive energy on a cost of service rate schedule without substantial notice to the utility. As a result, the utility does not

[55] Staff notes that under certain, limited circumstances, the customer may receive energy from its incumbent electric provider.

need to maintain generation resources to serve long term direct access participants. Long term direct access loads are excluded from load forecasts in Integrated Resource Plans and other resource acquisition decisions. Long term direct access customers are subject to transition adjustments for a limited period. PGE's current long term direct access tariff requires long term direct access customers to be subject to transition adjustments for five years.

Q. What long term direct access topics do you address in this testimony?

A. I address three long term direct access topics:

1. Staff opposes PGE's proposal to reflect ten years of fixed generation costs in transition adjustment rates.
2. Staff proposes to hold a workshop addressing direct access issues raised in this testimony.

Staff opposes PGE's Proposal for Ten Years of Fixed Generation Costs

Q. Why does Staff oppose PGE's proposal to reflect ten years of fixed generation costs in transition adjustment rates?

A. Staff objects to this proposal for a number of reasons:

1. PGE provides no evidence that the current transition adjustments result in unwarranted cost-shifts.
2. PGE's proposal will raise unnecessary barriers to a competitive energy market.
3. PGE's proposal may result in unnecessary and costly resource acquisitions, which will raise cost of service rates in the long run.

Q. What evidence does PGE present related to unwarranted cost-shifts?

A. PGE points to Exhibit 1308 as evidence of unwarranted cost-shifts. Exhibit 1308 is a table that multiplies \$34.60 by 438,000 by ten to arrive at \$75 million.[56] PGE asserts that this arithmetic provides evidence of cost-shifting.

Q. Why does Staff state PGE provides no evidence of cost-shifting?

A. PGE provides no explanation for why the \$75 million calculation represents cost-shifting, and whether that cost-shifting (if it exists) is unwarranted. PGE also provides no explanation for the relevance of ten years or 50 MWa. Without a basis for the number of years, PGE could have proposed *any* number of years with equal validity. For example, PGE could have claimed that the transition charge should collect 100 years of fixed generation costs, and that would be perfectly in line with PGE's rationale, because there is no rationale.

Q. What would constitute evidence of unwarranted cost-shifting?

A. In order to demonstrate cost-shifting, PGE should develop a multi-year model of cost of service rates with and without direct access load. Cost-shifting would exist if cost of service rates were higher when a portion of load is direct access rather than cost of service. In order to establish that cost-shifting is unwarranted, PGE would need to further establish that the negative impacts of cost-shifting are greater than the positive benefits of a competitive electricity market. PGE could accomplish this by showing that direct access does not improve the depth and liquidity of the energy market and by showing that PGE

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[56] This exhibit fails to account for leap years.

has not become more efficient and cost-effective in the face of market competition.

Q. Why does PGE's proposal raise unnecessary barriers to a competitive energy market?

A. PGE's proposal will make long-term direct access service an uneconomic choice for many customers. This is because participants will have to pay double for fixed generation costs for ten years rather than five years. The energy service supplier that supplies energy to long term direct access customers will recover fixed generation costs in its energy charge, while PGE also recovers fixed generation cost in the transition adjustment. This constitutes a barrier to a competitive energy market because less participation in the energy market means less competition. The barrier is unnecessary because PGE has not demonstrated unwarranted cost-shifting under the current mechanism.

Q. Why should the Commission be concerned with unnecessary barriers to a competitive energy market?

A. The Commission has a legislative mandate to establish policies that eliminate barriers to competitive retail markets structures.[57]

Q. How would PGE's proposal increase cost of service rates?

A. The primary driver of PGE's recent rate increases has been the addition of several costly generation facilities. PGE is facing a substantial capacity

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[57] Oregon Revised Statute 757.464.

shortfall in the wake of the Boardman plant closure.[58] This capacity shortfall means continued resource acquisitions. Long-term direct access is one program that reduces PGE's generation load, and consequently reduces PGE's capacity shortfall. PGE's proposal will reduce direct access participation, and as a result, will increase the likelihood that PGE will acquire costly generation resources and further increase cost of service rates.

Q. What is Staff's proposal with respect to the long term direct access transition adjustment?

A. Staff proposes maintaining the current five-year approach to transition adjustments.

PGE's current cap may be preventing direct access enrollment

Q. What is the load participation cap?

A. PGE's current long term direct access tariffs limit the total participation to 300 MWa. This cap has been in place since 2002.[59]

Q. Is PGE's cap currently binding?

A. Staff understands that PGE is close to the 300 MWa limit. If PGE has any customers larger than the current room in the program, then the cap is binding.

Staff proposes to hold a workshop addressing direct access.

Q. Why does Staff propose to hold a workshop addressing direct access?

A. As noted earlier in this testimony, PGE is facing a substantial capacity shortfall when Boardman closes. One reasonable solution to filling this capacity

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[58] *See* page 340 in Volume 1 of the IRP.
[59] Staff/806 PGE Advice 02-17

shortfall is to rely on additional load switching from cost of service to long term direct access. The current integrated resource planning process does not include direct access as a resource when optimizing the system. However, Direct Access could play a similar role that energy efficiency plays. Direct access reduces both the Company's energy needs and capacity needs, at little or no cost to customers. In fact, Direct Access reduces capacity needs at a negative cost due to the transition adjustments. This suggests that Direct Access could play a pivotal role in filling future capacity needs for PGE.

Staff suggests that parties hold a workshop to discuss the status of PGE's direct access program. This workshop could address the following:

- Potential benefits and risks of assigning a value to avoided capacity costs associated with long term direct access load.
- Approaches to measuring direct access related cost shifts.
- Appropriateness of the current 300 MWa enrollment cap.

ISSUE 10. ELECTRIC SERVICE SUPPLIER DECERTIFICATION

Q. Please summarize PGE's proposal regarding updating the language in its Rule K regarding ESS scheduling.

A. PGE proposes to add language to its Rule K to allow PGE to petition the Commission to decertify an ESS if the ESS does not follow certain scheduling practices. PGE provided three analyses of three months of data in support of its request.

Q. What is Staff's recommendation regarding PGE's proposal?

A. Staff recommends that the Commission reject PGE's proposal to update the language in its Rule K tariff to address this issue.

First, Staff finds that PGE's proposal is unnecessary in order to provide relief for the alleged issue, and assumes a policy position not investigated or decided by the Commission. The Company always has the ability to petition the Commission for an investigation or other appropriate relief. Moreover, Staff is not aware of a broad Commission policy regarding the decertification of an ESS due to scheduling variances. Therefore, Staff finds it premature to assume a policy basis for the requested language change in PGE's tariff.

Second, Staff finds that PGE's request would benefit from PGE increasing the time frame for analysis related to this issue and providing evidence of a cost impact related to this issue.[60] Without an understanding of the impacts to cost of service customers and reliability, it is difficult to evaluate whether PGE's concern has merit. Further, PGE should provide analysis and

[60] Staff requested this information in OPUC DR 267 through 269. Staff/801.

support for its conclusion that two occurrences of 20 percent of hourly deviations greater than 20 percent of the scheduled amount occurring in a calendar month would address its concerns. Absent such analysis, it is not possible to determine whether PGE's concern, if valid, is addressed by its proposal.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 335
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Exhibits in Support
Of Opening Testimony

June 6, 2018

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. 128
Dated March 15, 2018

Request:

Please refer to the PGE Exhibit 200 workpaper "2019 Plant Detail.xlsx".

a. **Please provide the source data file that was used to generate the image on sheet "Carty plant incremental."**
b. **Please provide the source data used to generate the plant balances on sheet "Plant Sum."**
c. **Please provide PGE's actual gross plant, depreciation expense, and accumulated depreciation by plant account and location by month beginning in January 2016. This request is ongoing and should be supplemented July 1, 2018, September 1, 2018, and November 1, 2018.**
d. **Please provide PGE's forecasted gross plant, depreciation expense, and accumulated depreciation by plant account and location by month ending on January 1, 2020. This request is ongoing and should be supplemented July 1, 2018, September 1, 2018, and November 1, 2018.**

Response:

Based on a discussion with the OPUC Staff on March 19, 2018, the dates specified for supplemental responses (see parts (c) and (d)) 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).

a. In the 2018 Staff Plant Audit AIR 002, PGE described how fixed assets that are currently not included in rate making are reported and how the incremental fixed costs associated with the construction of the Carty Generating Plant are treated. The following table identifies the FERC accounting groups in use for this separation for reporting purposes.

UE 335 PGE Response to OPUC DR No. 128
March 29, 2018
Page 2

341-05 Buildings – Carty Incremental
342-05 Fuel holder – Carty Incremental
344-05 Generator Other Prod - Carty Incremental
346-05 Misc Power Plant Equip – Carty Incremental

The balances in these FERC account groups as of December 31, 2017 are included in Attachment 128-A.

Attachment 128-A is protected and subject to Protective Order No. 18-047.

b. PGE follows the process of either assigning or allocating plant balances. This is performed initially by assigning plant costs directly to the categories Generation, Transmission, Distribution, Metering, Billing, Other Consumer, and Retail. Once this assignment is finished, allocations of remaining plant balance is accomplished through other methods such as identifying general and intangible plant and allocating based on the area of the company that they support. The overall process is to maintain a reasonable allocation method for plant balances year over year.

- Attachment 128-B provides the Major Location and the 300-level FERC account. These costs are directly assigned based on 300-level FERC account and the specifically assigned physical location of the plant balance to the corresponding category within the 300-level FERC account.
- Attachment 128-C Plant Summary forecast is the assignment of the forecasted year end 2018 Plant Balance by classifications. This balance excludes the incremental Carty as identified.
- Attachment 128-D Plant Balance Roll-forward 2018 is the monthly and forecasted year-end 2018 balance distributed through Attachment 128-C Plant Summary.
- Attachment 128 E Detailed Plant Balance for Forecast 2018 represents the forecasted details for Plant summary.

Attachment 128-E is protected and subject to Protective Order No. 18-047

c. See Attachment 128-B for actual monthly 2016 and 2017 gross plant and Attachment 128-F for quarterly depreciation expense and accumulated depreciation for 2016 and 2017.

PGE will provide 2018 monthly actual updates as of May 31, July 31, and Sept 30.

d. Based on clarification with the OPUC Staff on March 22, 2018, since PGE's rate base forecast is as of December 31, 2018, and since no costs from beyond that date are in the UE 335 rate base, then no further information is expected in this response for 2019 costs.

- PGE response to UE 335 ICNU DR 001_Attach A provides PGE's gross utility plant in service forecast, as of December 31, 2018 by FERC account.
- UE 335 ICNU DR 001_Attach B and DR 002 provide PGE's accumulated depreciation and depreciation expense forecast as of December 31, 2018.
- "Ex 203 Depr" and "Ex 204 Amort" tabs in PGE's Exhibit 200 work paper "Exhibit Support 2019_Tax Plan" provide 2018 budget and 2019 forecasted depreciation expense.

PGE will provide 2018 monthly actual updates as of May 31, July 31, and Sept 30.

UE 335

Attachment 128-A

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-047

FERC accounting groups balances

UE 335

Attachment 128-B

Provided in Electronic Format only

Monthly Gross Plant 2016-2017

UE 335

Attachment 128-C

Provided in Electronic Format only

2018 Plant Summary Forecast

UE 335

Attachment 128-D

Provided in Electronic Format only

2018 Plant Balance Rollforward

UE 335

Attachment 128-E

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-047

2018 Detailed Plant Balance Forecast

UE 335

Attachment 128-F

Provided in Electronic Format only

Quarterly Depreciation Expense and Accumulated Depreciation
2016-2017

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. 130
Dated March 15, 2018

Request:

Please provide the mapping of PGE's projects into PGE's plant accounts for projects transferred to plant after July 1, 2017 or forecasted to transfer to plant before January 1, 2019.

Response:

PGE is providing two attachments to respond to the forecasted plant additions between January and December 2018. Attachment 130-A provides a list of Funding Projects with description and the estimated fully loaded cost that are expected to close to plant during 2018. Attachment 130-B provides an estimated assignment of these plant costs to FERC 300-account level. Funding Projects consist of numerous accounting work orders. Thus, the assignment of a Funding Project and its costs are not one to one at the FERC 300-account level. The assignment of these estimated costs occurs within PGE's PowerPlan financial system using various depreciation group methodologies.

Attachment 130-C provides Funding Projects and the associated dollars closed to plant within 300-level FERC accounts by month from July through December of 2017.

UE 335

Attachment 130-A

Provided in Electronic Format only

Protected Information Subject to Protective Order 18-047

2018 Funding Projects Forecasted to Close to Plant

UE 335

Attachment 130-B

Provided in Electronic Format only

2018 Projects Forecasted to Close to Plant by FERC Account

UE 335

Attachment 130-C

Provided in Electronic Format only

July – December 2017 Projects Closed to Plant by FERC Account

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. 131
Dated March 15, 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:

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

UE 335 PGE Response to OPUC DR No. 131
March 29, 2018
Page 2

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.

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. 132
Dated March 15, 2018

Request:

Please provide the following for each blanket project with amounts transferred to plant after July 1, 2017 or forecasted to transfer to plant before January 1, 2019.

a. **Please identify each individual sub project or work order and the actual or forecasted costs of each subproject or work order. If this request is burdensome please provide such data for sub projects and work orders exceeding $10,000.**
b. **For each blanket project with forecasted amounts transferred to plant in this rate case, please explain how the amount was forecasted. If this request is burdensome please provide such data for sub projects and work orders exceeding $10,000.**

Response:

PGE objects to this request based on the grounds that it is unduly burdensome. Without waiving its objection, PGE responds as follows:

The general definition that PGE uses for blanket projects is applied to purchases of equipment wherein the month they are received, these costs and assets are classified as used and useful and are transferred to plant in that same month. Types of items included here are computers, vehicles, furniture, and communication equipment. These are generally classified as general plant assets.

The other use of blanket projects occurs with Distribution work where the construction period is expected to be less than 30 days. This short period includes the large value of work installing poles, conductor, customer meters, line transformers, lighting, and those various components associated with this equipment. These assets and costs are considered used and useful in the month incurred and transferred to plant accounts at that time. PGE estimates the amount of expenditure for this type of work based on the prior year's construction information. Throughout the year, PGE Service Design Project Managers and Engineers create estimates for all of the construction work to be scheduled through the Maximo work management system. Thousands of work orders are created through this process and due to this volume; it would be overly burdensome to provide each work order with actual or estimated costs.

Attachment 132-A provides Funding Projects that meet the above definitions as blanket projects for the period of July to December 2017.

Attachment 132-B provides Funding Projects that meet the above definitions as blanket projects for 2018 forecasted Funding Projects closing to plant.

UE 335

Attachment 132-A

Provided in Electronic Format only

July to December 2017 Blanket Projects Close to Plant

UE 335

Attachment 132-B

Provided in Electronic Format only

2018 Blanket Projects Close to Plant Forecast

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. 133
Dated March 15, 2018

Request:

Please provide the following information for all plant included in rate base and forecasted to transfer to plant after December 31, 2018:

a. **Project description;**
b. **Amount transferred to plant by month;**
c. **Reason for including in rate base; and**
d. **Basis for forecasted amounts and timing.**

Response:

There are no projects included in PGE's rate base that are scheduled to close to plant after December 31, 2018.

March 27, 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. 134
Dated March 15, 2018

Request:

Please provide the following information for all capital additions made to Carty Plant, Grasslands Switchyard, or the connecting transmission after December 31, 2017:

a. **Project description;**
b. **Project ID;**
c. **Amount and date of transfer; and**
d. **Amount of plant included in rate base.**

Response:

The following actual projects and costs closed to plant in January and February 2018. This type of on-going capital work is typical for all of PGE's thermal plants after they become operational.

P36451 - Upgrade Heat Trace System $8,876. This amount represents trailing costs related to the total approved project of $700,000 incurred cost, plus loadings, placed into service in 2017. This project replaced faulty elements of the Heat Trace System at Carty.

P35172 - PSES Generation Fitness Fund – Install Access Platforms $3,382. This amount is part of the total capital blanket project P35172, which funds known and emerging generic and routine capital jobs that are essential for maintaining the fitness (including safety, reliability, and minor upgrades) of PGE Generation plants.

P35212 - Misc. Pumps, Valves, Motors Replacement $1,107. This amount is part of the total capital blanket project P35212, which funds expenditures that are immediate in need by our gas plants and cost less than $30,000.

UM 335 PGE Response to OPUC DR No. 134
March 27, 2018
Page 2

There were no specific plant additions identified at the time of PGE's rate case filing specific to Carty. PGE will use P35172 - PSES Generation Fitness Fund, and P35212 - Misc. Pumps, Valves, Motors Replacement project funds when work is identified under their specific guidelines. If other projects are identified outside of their scopes, those projects will need to be submitted to PGE's internal Capital Review Group for approval.

PGE's rate base excludes capital costs associated with the construction of the Carty Plant that exceeds the original cost estimate of $514 million.

March 27, 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. 135
Dated March 15, 2018

Request:

Please provide the following information for all capital primarily stored or used at the Carty Plant, Grasslands Switchyard, or the connecting transmission after December 31, 2017 but not considered to be part of Carty Plant, Grasslands Switchyard, or the connecting transmission:

a. **Project description;**
b. **Project ID;**
c. **Amount and date of transfer; and**
d. **Amount of plant included in rate base.**

Response:

There are no capitalized assets stored or used at the Carty Plant, Grasslands Switchyard, or for transmission connection that are not part of the Carty Project, Grasslands Switchyard, or for the transmission connection.

As noted in PGE's response to OPUC Data Request No. 134, PGE's rate base excludes capital costs associated with the construction of the Carty Plant that exceeds the original cost estimate of $514 million.

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 267
Dated April 19, 2018

Request:

PGE/1300, Macfarlane – Goodspeed/42 states "PGE's COS customers may be harmed by covering the costs of providing the energy to make sure the direct access customers are served."

- **a. Please provide all workpapers and analysis, including estimates quantifying the harm to COS customers, by month, for the three most recent years for which data is available.**
- **b. Did PGE consider modifying its default service offerings to this concern? If no, why not?**

Response:

a. PGE has not prepared work papers. The harm to cost-of-service customers due to poor scheduling comes in the form of decreased reliability. Please see PGE's response to Calpine Energy Solutions, LLC's Data Request No. 016.

b. No. PGE is proposing modifications to its Rule K to include parameters for ESS scheduling to alleviate concern regarding poor scheduling practices. Please see PGE's response to AWEC Data Request No. 037, Attachment 037-A. Modifying default service does not address the problem of poor ESS scheduling and would transfer responsibility from the ESS to the direct access customer. PGE's Emergency Default Service under Schedule 81 is applicable to "Nonresidential Customers who are no longer receiving Direct Access Service and have not provided the Company with the notice required to receive service under the applicable Standard Service rate schedule." In addition, Emergency Default Service is only applicable for five days. After five days, the Customer will be billed at the applicable Standard Service rate schedule.

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 268
Dated April 19, 2018

Request:

Please supplement the information in Table 8 with the three most recent years of available data, by month, for all ESSs submitting schedules to PGE.

Response:

Confidential Attachment 268-A provides the requested information for the period from January 2015 through March 2018. Because the file contains customer-specific detail that could provide information as to the identity of each ESS listed in PGE Exhibit 1300, Table 8, PGE has not posted the requested material to Huddle. Rather, parties wishing to see specific information should contact Stefan Brown at (503) 464-7805.

Attachment 268-A is protected information and subject to Protective Order No. 18-047.

UE 335

Attachment 268-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

ESS Scheduling Compared to Actual

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 269
Dated April 19, 2018

Request:

Please supplement the information PGE's Response to Calpine DR 5 with the three most recent years of available data, by month, for all ESSs submitting schedules to PGE.

Response:

Confidential Attachment 269-A provides the requested information for the period from January 2015 through March 2018. Because the file contains customer-specific detail that could provide information as to the identity of each ESS listed in PGE Exhibit 1300, Table 8, PGE has not posted the requested material to Huddle. Rather, parties wishing to see specific information should contact Stefan Brown at (503) 464-7805.

Attachment 269-A is protected information and subject to Protective Order No. 18-047.

UE 335

Attachment 269-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

ESS Scheduling Compared to Actual

May 2, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 270
Dated April 19, 2018

Request:

Please provide all project documents associated with the CET including but not limited to the following:

a. **Business case;**
b. **Statement of work;**
c. **Project requests and proposals;**
d. **Project charters;**
e. **Project management plan;**
f. **Action log;**
g. **Risk register (risk log);**
h. **Issues log;**
i. **Status reports**
j. **Budgets;**
k. **Closing documents;**
l. **Request for Proposals;**
m. **Third party contracts;**
n. **Third party deliverables;**
o. **Invoices;**
p. **Training materials;**
q. **Program manuals and documentation;**
r. **Change requests;**
s. **Communications with project sponsor; and**
t. **Communications with other stakeholders.**

Response:

PGE objects to this request as it is unduly broad and overly burdensome. Subject to and without waiving this objection, PGE responds as follows:

Pursuant to the conversation with OPUC Staff on April 24, 2018, PGE will be providing parts (d), (e), (n), and (r) with this response. All other parts will be provided as they are completed.

d. Attachment 270-A provides the Statement of Work for Accenture, which acts as the project charter, as well as the project charters associated with the Interactive Voice Response, Bill Print Project, and Web Site Integration

e. Attachment 270-B provides the project management plan.

n. Attachment 270-C provides the list of all third party deliverables for Accenture and TMG Utility Advisory Services, Inc.

r. Attachment 270-D provides all change requests between PGE and Accenture.

Attachments 270-A, 270-B, 270-C, and 270-D are protected information and subject to Protective Order No. 18-047.

UE 335

Attachment 270-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Project Charter

UE 335

Attachment 270-B

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Project Management Plan

UE 335

Attachment 270-C

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Third Party Deliverables

UE 335

Attachment 270-D

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Change Requests

May 10, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE's *First Supplemental* Response to OPUC Data Request No. 270
Dated May 10, 2018

<u>Request:</u>

Please provide all project documents associated with the CET including but not limited to the following:

- **a. Business case;**
- **b. Statement of work;**
- **c. Project requests and proposals;**
- **d. Project charters;**
- **e. Project management plan;**
- **f. Action log;**
- **g. Risk register (risk log);**
- **h. Issues log;**
- **i. Status reports**
- **j. Budgets;**
- **k. Closing documents;**
- **l. Request for Proposals;**
- **m. Third party contracts;**
- **n. Third party deliverables;**
- **o. Invoices;**
- **p. Training materials;**
- **q. Program manuals and documentation;**
- **r. Change requests;**
- **s. Communications with project sponsor; and**
- **t. Communications with other stakeholders.**

Response (Dated May 2,2018):

PGE objects to this request as it is unduly broad and overly burdensome. Subject to and without waiving this objection, PGE responds as follows:

Pursuant to the conversation with OPUC Staff on April 24, 2018, PGE will be providing parts (d), (e), (n), and (r) with this response. All other parts will be provided as they are completed.

d. Attachment 270-A provides the Statement of Work for Accenture, which acts as the project charter, as well as the project charters associated with the Interactive Voice Response, Bill Print Project, and Web Site Integration

e. Attachment 270-B provides the project management plan.

n. Attachment 270-C provides the list of all third party deliverables for Accenture and TMG Utility Advisory Services, Inc.

r. Attachment 270-D provides all change requests between PGE and Accenture.

Attachments 270-A, 270-B, 270-C, and 270-D are protected information and subject to Protective Order No. 18-047.

First Supplemental Response (Dated May 10, 2018):

PGE is providing parts (a), (b), (c), (f), (g), (h), (i), (j), (k), (l), (m), (o), (p), (q), (s), and (t) with this response. Other parts will be provided as they are completed.

a. Attachment 270-F contains various documents associated with the business case for the CET Program.

b. Attachment 270-G contains Statements of Work from Accenture, Hitachi, and TMG Consulting.

c. Project requests and proposals can be found in PGE's response to CUB Data Request No. 004, in Confidential Attachments 004-A, 004-B, and 004-C.

f. PGE does not use a separate action log for this project.

g. Attachment 270-H contains the log for CET Risks and Issues.

h. See Attachment 270-H.

i. Attachment 270-E provides the Status Reports in an Excel spreadsheet, as well as updates presented to the Sponsor Committee, Steering Committee, and Finance Committee.

j. Budget Summaries are contained in Attachment 270-E, in the Finance Committee updates.

k. The project is not yet closed, and the closure process will not start until June 1, 2018. PGE will submit closing documents once they are available.

l. The Request for Proposals can also be found in PGE's response to CUB Data Request No. 004.

m. The Statements of Work provided in part (b) of this response serve as the contracts that PGE signed with third parties.

o. Attachment 270-I contains a spreadsheet of CET Invoices.

p. Training Materials are embedded in PGE's knowledge management system in Tualatin. Staff was provided an opportunity to view them on May 3, 2018. Another visit may be scheduled to view the materials if the first was not sufficient.

q. Program manuals and documentation can be found on Oracle's website at:
https://docs.oracle.com/cd/E72219_01/documentation.html

s. Communications with the project sponsor are contained in Attachment 270-E, in the Sponsor Committee updates.

t. Attachment 270-J contains PGE's CET program presentations to Staff and CUB during PGE's last five general rate cases, including UE 335.

Attachments 270-E, 270-F, 270-G, 270-H, 270-I, and 270-J are protected information and subject to Protective Order No. 18-047.

UE 335

Attachment 270-E

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Status Reports and Updates

UE 335

Attachment 270-F

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

CET Business Case

UE 335

Attachment 270-G

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Statements of Work

UE 335

Attachment 270-H

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Risks and Issues Log

UE 335

Attachment 270-I

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Invoices

UE 335

Attachment 270-J

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Communications with Stakeholders

May 2, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 271
Dated April 19, 2018

Request:

Please refer to PGE/900, Stathis – Dillin /10 and 16. Please provide all alternatives analysis performed on the CET project. Please include supporting workpapers.

Response:

PGE objects to this request on the grounds that it is overly broad and unduly burdensome. Subject to and without waving its objection, PGE responds as follows:

PGE provided the alternatives analyses performed on CET in PGE's response to CUB Data Request No. 004, as well as in PGE Exhibit 901. PGE will be providing additional analysis in its response to OPUC Data Request No. 270, items (s) and (t).

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 272
Dated April 19, 2018

Request:

Please refer to PGE/900, Stathis – Dillin/9. Please provide the following information for the 2002 CIS and the 2000 MDMS:

a. **Development O&M cost;**
b. **Capital cost of initial deployment;**
c. **Ongoing O&M cost;**
d. **Enhancement O&M cost by year; and**
e. **Enhancement Capital cost by year.**

Response:

PGE objects to this request on the basis of undue burden and that the information it seeks is not relevant or reasonably calculated to lead to the discovery of admissible evidence in the current proceeding. Without waving this objection, PGE responds as follows:
PGE does not have detailed information regarding the CIS and MDMS systems because PGE changed accounting systems in 2011 (as discussed in PGE's 2014 general rate case, Docket No. UE 262) and did not retain prior detail beyond that filed in the previous general rate cases. However, PGE does have some historical information regarding the implementation cost of the Banner CIS, retained from PGE's 2002 General Rate Case (Docket No. UE 115). The MDMS, however, was implemented between rate cases and as such, had no incremental costs that were specifically identified in UE 115 or the subsequent 2007 general rate case (Docket No. UE 180). Consequently, PGE does not have information about this implementation and cannot retrieve it due to the amount of lapsed time and change in accounting systems.

a. The forecasted development O&M cost for CIS was approximately $3.06 million.
b. The capital cost of the initial deployment for CIS was $35.2 million including loadings, allocations, and AFUDC.
c. Forecasted ongoing annual O&M costs for CIS were $2.7 million.

d. PGE does not have information regarding the enhancement O&M costs due to the change in accounting systems.
e. PGE does not have information regarding the enhancement Capital costs due to the change in accounting systems.

April 30, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 274
Dated April 19, 2018

Request:

Has PGE performed any review or evaluation of PGE's information technology department from January 1, 2013 to the present? If yes please provide all related documents.

Response:

PGE objects to this request on the grounds that it is overly broad and unduly burdensome. Notwithstanding this objection, PGE responds as follows:

PGE conducts or authorizes periodic reviews using commercially available data. One such review is a benchmarking study conducted in 2015 by Gartner, Inc. that used data collected to benchmark PGE Information technology (IT) against other available benchmarks in 2015. This document was provided as part of PGE's response to OPUC Data Request No. 194, Confidential Attachment 194-C.

Additionally, PGE hired Mandiant to conduct an assessment on our Information Security Program, a summary of which was provided in confidential work papers for UE 319, supporting PGE Exhibit 1802C (provided as Attachment 274-A). Subsequently, PGE hired PricewaterhouseCoopers (PwC) to work jointly with PGE to extend the Mandiant suggested timeline from 2 years to 5 years. A summary of the joint work of PGE and PwC was provided in UE 319, in confidential work papers supporting PGE Exhibit 500 (provided as Attachment 274-B).

Attachments 274-A and 274-B are protected information and subject to Protective Order No. 18-047.

UE 335

Attachment 274-A

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

PGE Security Program Assessment Executive Report

UE 335

Attachment 274-B

Provided in Electronic Format

Protected Information Subject to Protective Order 18-047

Risk-based Prioritizations and Updated Security Roadmap

May 3, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 275
Dated April 19, 2018

Request:

Please provide all formal policies and procedures related to project management, program management, and project portfolio management.

Response:

PGE objects to this request on the basis that it is overly broad and unduly burdensome. Subject to and without waiving its objection, PGE responds as follows:

Attachment 275-A provides PGE's Project Authorization Policy for all projects requesting funding approval and their post completion review process.

Attachment 275-B provides the 2010 management presentation to PGE's Board Finance Committee providing updates for monitoring major projects and for post-project completion reviews.

UE 335

Attachment 275-A

Provided in Electronic Format

PGE’s Project Authorization Policy

UE 335

Attachment 275-B

Provided in Electronic Format

PGE's Major Project Monitoring and Post Completion Review

PORTLAND GENERAL ELECTRIC CORPORATE POLICY

PROJECT AUTHORIZATION **Effective Date: 1/24/2017**

POLICY

All projects require an approved Funding Project request prior to committing resources, contracting for services, and/or initiating work.

Project review by Corporate Planning does not override or eliminate the need for (i) subsequent approval by officers, managers, and in some cases the board of directors; (ii) the need to fulfill subsequent requirements associated with contracting or purchase requisitions; (iii) the need to obtain legally required regulatory approvals; or (iv) a release from the lien of the Mortgage Indenture when necessary where the sales of assets are concerned.

DEFINITIONS

Project: an activity or group of activities that typically has a long-term impact on operations and expenditures and may extend over more than one capital and operating budget period.

For the purposes of this policy, projects include, but are not limited to:

- **Base Business Capital Projects**
  - **Regulated:** where costs would be included in our regulated prices (e.g., transmission, distribution, generation, information technology, etc.).
  - **Non-regulated:** where costs would not be included in our regulated prices.
- **Strategic Initiatives (Capital and O&M)**
  - Construction or acquisition of a new generating resource.
  - Major technology implementation.
  - Major upgrades to generation and T&D assets.
  - Internal development of a new business line or major new product.
- **Significant O&M Projects**
  - Non-recurring O&M projects with costs greater than $500,000, totaled over all years.
- **Sale of Assets**
  - Sale, lease, or disposition of assets with a value of $100,000 or greater, and all land sales.
- **Preliminary Engineering Project**
  - Preliminary work to determine the feasibility of a capital project under consideration and if it will result in capital funding
  - Includes only costs that would meet capitalization criteria

PRACTICE

All project requests must be submitted to Corporate Planning via a Funding Project request to ensure that requests to commit company resources receive thorough business review and authorization prior to initiating work. Corporate Planning will do an objective review, including ensuring that the associated costs and revenues are accurately reflected in the annual budget and financial projections.

PORTLAND GENERAL ELECTRIC CORPORATE POLICY

Corporate Planning will also review the scope, justification and other relevant information to help ensure that the Funding Project request is complete and contains all necessary information.

Funding Project Documentation
Submitted Funding Project requests are entered and stored in the PowerPlan system, and include the following information:
- Description of the scope, justification and cost of a project.
- Description of any consequences or risks of doing or not doing the project.
- Description of benefits the project expects to deliver.
- Supporting documentation as appropriate.

The Funding Project request must be signed by an authorized person within the functional area sponsoring the project before it can be submitted for review. The proposed total incurred dollar amount of the project determines who can approve the Funding Project request:

Project Submittal Requirement	
Sponsor	**Sponsor Level**
Chief Executive Officer	No dollar limit
Chief Financial Officer	$2,000,000
Vice President	$1,000,000
General Manager, Director	$500,000
Manager	$200,000

NOTE: Manager, as used in this table, excludes project manager and supervisor. For jointly owned facilities, the dollar thresholds listed above represent 100 percent of the proposed total project cost.

Base Business Capital and Preliminary Engineering Projects
Once Corporate Planning has reviewed a base business capital or preliminary engineering project, that project must be submitted to the Capital Review Group (CRG) for funding recommendation.

Strategic Initiatives
Strategic initiatives require additional reviews. Contact the Corporate Planning manager for guidance.

Emergency Approval Requests
When unplanned events occur, managers may proceed with projects without receiving prior authorization in order to:
- Restore service to customers
- Prevent significant financial loss
- Eliminate a hazard that affects public or employee safety

PORTLAND GENERAL ELECTRIC
CORPORATE POLICY

Managers must notify Corporate Planning within one business day of initiating emergency project work regardless of whether such costs are operating or capital costs. Managers must submit a Funding Project request to Corporate Planning for all projects within 30 days of the first day of the emergency.

Base Business Capital and Preliminary Engineering Project Changes
If there is a project change in a base business capital or preliminary engineering project, that project must first be resubmitted to Corporate Planning via an updated Funding Project request. Once Corporate Planning has completed its review, the project must be resubmitted to the CRG. Project changes include:

- Delays of completion into the next calendar year which results in a delay of more than $100,000 in incurred project costs. These revisions should be submitted as soon as possible, but are required no later than January 31 of the year into which the costs are being delayed.
- Significant changes in scope, such as business requirements or deliverables. These must be resubmitted for review and authorization within 60 days of identifying the change.
- Terminations of a project prior to completion. These must be resubmitted for review and authorization. The process must be completed within the calendar month that the termination will occur.
- Project budget variances. Projects with budget variances that meet the following criteria may have their funding limited or reduced, or the manager may be required to request additional funding:

Year to Date Variance to Current Approved Budget	Full Year Budget Variance to Current Approved Budget
Variance is at least $250,000 for two consecutive months	Variance is at least $100,000, and is the lesser of 10% of the approved annual budget or $250,000, for two consecutive months

Strategic Project Changes
All projects with budget changes that meet the following criteria must be resubmitted to Corporate Planning for review and authorization after the change is identified:

Year to Date Variance to Current Approved Budget	Full Year Budget Variance to Current Approved Budget
Variance is at least $5,000,000 for two consecutive months	Variance is at least $5,000,000 for two consecutive months

For other types of changes, including increasing total project funding, contact the Corporate Planning manager for guidance.

Project Closure
All capital projects require a job completion/termination date be entered in the PowerPlan system within the calendar month of project completion or termination.

Post Completion Review
The project sponsor will initiate a project completion review within 30 days of project completion on the following projects:
- All capital projects with costs over $1 million incurred over the life of the project.
- Additional projects as selected by Corporate Planning.

The project sponsor will submit the project completion review to Corporate Planning by the date specified on the Post-Completion Review form.

Reviews will include, but are not limited to, adherence to authorized project scope, evaluation of whether project goals were achieved, cost variance explanations, lessons learned, and verification of compliance with project authorization guidelines. The review will be prepared and signed by the sponsoring manager and officer. Ongoing projects (e.g., vehicle vintage replacement, computer vintage replacement, T&D blanket projects, substation fitness program, etc.) will not be included in the post-completion review process.

RESPONSIBILITIES

Managers
Managers are responsible for ensuring their operating and capital budget requests, scope changes and projects go through the proper analytical review, departmental review (e.g., Legal, Regulatory) and approval process, as outlined in the Corporate Approval Process Policy. For each project in their area, managers are also responsible for:
- Ensuring the project sponsor obtains necessary approvals from management, officers, and the Board of Directors.
- Communicating project status to project stakeholders.
- Monitoring status throughout the project and ensuring the project sponsor follows procedures for project variance and scope changes and project closure.
- Ensuring the project sponsor submits any required Post-Completion Review form, as required.
- Ensuring that all applicable regulatory approvals and, if necessary, a release from the lien of the Mortgage Indenture are obtained.

Project Sponsors
- Ensure information and cost projections in project requests are complete, accurate and communicated to all affected parties prior to requesting approval.
- Obtain necessary approvals from management, officers, and the board of directors.
- Communicate project status to managers and other project stakeholders.
- Monitor status throughout the project and follow procedures for project variance and scope changes and project closure.

- Submit a Post-Completion Review form, as required.
- Ensure that all applicable regulatory approvals and, if necessary, a release from the lien of the Mortgage Indenture are obtained.

Project Managers

Project managers are responsible for working with project sponsors to ensure that project information is complete, accurate and communicated to affected parties. Project Managers also work with the project sponsors on the following:

- Ensuring information and cost projections in project requests are complete, accurate and communicated to all affected parties prior to requesting approval.
- Communicating project status to project sponsors, managers and other project stakeholders.
- Monitoring status throughout the project and following procedures for project variance and scope changes and project closure.
- Submitting the Post-Completion Review form, as required.

Capital Review Group (CRG)

- Review and corporately prioritize Base Business Capital projects received, and assemble prioritized projects into the Capital Expenditures Plan (the Plan).
- Review Base Business Capital project variances and make recommendations regarding whether a project should continue to be funded, receive additional funding, have funding reduced, be deferred or be cancelled.
- Submit the Base Business Capital projects recommended by the CRG to the CEO for review and approval.
- Remove Base Business Capital Projects from the Plan, or defer them, based on emerging corporate needs and priorities.
- The CRG may recommend capital expenditures associated with emerging work up to the total amount of the Plan plus fifty percent of the current unallocated CEO Non-Budgeted Matter amount.
- Review Strategic Projects to evaluate potential impacts on Base Business Projects.
- Notify CEO and CFO of changes to scope, timing or cost of Projects.

Corporate Planning

- Conduct project business reviews.
- Administer CEO Non-Budgeted matters amount.

Asset Accounting

Determine if submitted and approved projects are adhering to PGE's capitalization guidelines

SPONSORING ORGANIZATION: Chief Financial Officer

OTHER CONTACTS: Corporate Planning

ADDITIONAL RESOURCES:

Corporate Approval Process Policy

Supply Chain Policy

APPD 4-003-01 Capitalization Guidelines

APPD 4-900-01 Accounting for Preliminary Engineering- (Preliminary Survey and Investigation FERC 183)

APPD 5-401-01 Job Approval Process

Corporate Planning Project Budgeting Site

PGE Board of Directors' Policy Statement on Authority of Management

Power Supply Transaction Approval Process

Finance Committee Meeting

Major Project Monitoring & Post Completion Reviews

October 26, 2010

Portland General Electric

Overview of Today's Discussion

Recommendations presented herein are intended to:

- Enhance the Board of Directors ability to monitor management's performance with major capital projects
- Focus Board of Directors attention on larger strategic projects
- Track project performance from initial approval and subsequent project revisions through completion
- Establish appropriate thresholds and review intervals

Portland General Electric

Threshold for Project Approval

Current Practice

- Each capital project or series of related capital projects with an anticipated expenditure in excess of $2.5 million or greater is itemized and described in the Capital Budget
- Detailed Project Profile document provided for each project in excess of $2.5 million

Recommendation

- Increase the threshold to $5 million and exclude recurring customer driven distribution projects
- Provide a short summary for projects with anticipated expenditures between $5 million and $25 million
- Provide detailed presentation for projects with anticipated expenditures in excess of $25 million
- Include projects less than $5 million if outside the normal course of business or new type of transaction
  - i.e. solar investments

Portland General Electric

Frequency of Review

Current Practice

- Status of previously approved projects presented to Finance Committee at management's discretion

Recommendation

- At each quarterly Finance Committee meeting, a brief overview will be presented summarizing the to-date status of all major projects that exceed $25 million
  - Status
  - Project to-date costs
  - Total approved amount
  - Forecasted expenditures
  - Earned Value Analysis or other appropriate metric

Portland General Electric

Frequency of Review (con'd)

Recommendation

- Separate updates for projects greater than $25 million will be presented to the Finance Committee by the sponsoring officer and / or manager in the event of significant changes or developments such as the following:
  - The total loaded cost of the project varies by the lesser of 10% or $5.0 million from the originally approved amount
  - The project is experiencing a significant change in scope regardless of the dollar impact
  - The project is experiencing significant challenges that pose added risk to the project or unexpected delays
  - Multi-year projects that have achieved certain milestones

Portland General Electric

Post Completion Reviews

Current Practice

- Post Completion Reviews are reviewed by the Audit Committee
  - Strategic Projects >$25k
  - Economic Projects >$500k
  - Any project >$1 million
  - Randomly Selected
- Quarterly review

Recommendation

- Shift review responsibility to Finance Committee
  - All projects greater than $5 million
- Semi annual review
- Management will continue to review post completion reviews for projects less than $5 million and a summary report will be provided to the Board annually

Portland General Electric

Post Completion Review Criteria

- **Executive Summary**
  - Purpose, objectives, pertinent facts, significant challenges
- **Project Overview**
  - Were the objectives, as laid out in the final project profile, accomplished?
  - Were there project scope changes from the original project profile?
  - Was all work included in the original scope completed?
  - Did project meet the original timeline
- **Variance Explanation**
- **Lessons Learned**

Portland General Electric

Next Steps

- **Approve amendment to Board of Directors Policy Statement on Authority of Management**
  - "Each capital project or series of related capital projects contained in the Capital Budget, including tangible and intangible capital assets and improvements, with an anticipated expenditure in excess of $5.0 million, and each lease obligation (capital and operating), with a present value in excess of $5.0 million, shall be itemized and described in the Capital Budget"
- **Approve amendment to Finance Committee Charter**
  - "The Committee shall be responsible for overseeing the Company's process for post-completion review of capital projects and shall receive periodic reports from management on the results of such reviews"
- **No amendment required for the Audit Committee Charter**

Portland General Electric

CASE: UE 335
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Exhibits in Support
Of Opening Testimony

REDACTED
June 6, 2018

STAFF EXHIBIT 802

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 18-047. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 335 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 335
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 803

Exhibits in Support
Of Opening Testimony

June 6, 2018

PGE Non-Intertie Transmission Revenue

Year	Transmission Revenue	Staff Forecast	PGE Forecast	Staff Adjustment
2015	$ 2,971,892			
2016	$ 2,899,444			
2017	$ 3,557,592			
2018		$ 3,728,676	$ 3,474,800	
2019		$ 4,021,526	$ 3,202,930	$ 818,596

Other Revenue Forecast

Transmission Rev Adj	$ 818,596
Pole Rev Adj	$ 1,204,000
Total Other Rev Adj	$ 2,022,596

CASE: UE 335
WITNESS: LANCE KAUFMAN

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STAFF EXHIBIT 804

Exhibits in Support
Of Opening Testimony

June 6, 2018

Schedule 7 Bill Change

Year	Decoupling type: Partial	Full
2002	-0.3	
2003	-2.1	-1.9
2004	-2.2	-1
2005	-1	0.2
2006	0.3	0.9
2007	0.9	0.8
2008	1.3	0.8
2009	2.1	1.4
2010	-0.3	-1.5
2011	1.8	1.9
2012	-0.9	-1.8
Variance	2.146545	1.977333

		F-Critical Value (.05,10,9)	
Variance Test Tatistic:	1.086	3.137	Fail to reject null hypothesis of equal variance

Staff/804
Kaufman/2

1.3.5.9. F-Test for Equality of Two Variances

Purpose: Test if variances from two populations are equal

An F-test (Snedecor and Cochran, 1983) is used to test if the variances of two populations are equal. This test can be a two-tailed test or a one-tailed test. The two-tailed version tests against the alternative that the variances are not equal. The one-tailed version only tests in one direction, that is the variance from the first population is either greater than or less than (but not both) the second population variance. The choice is determined by the problem. For example, if we are testing a new process, we may only be interested in knowing if the new process is less variable than the old process.

Definition

The F hypothesis test is defined as:

H_0: $\sigma_1^2 = \sigma_2^2$

H_a:
- $\sigma_1^2 < \sigma_2^2$ for a lower one-tailed test
- $\sigma_1^2 > \sigma_2^2$ for an upper one-tailed test
- $\sigma_1^2 \neq \sigma_2^2$ for a two-tailed test

Test Statistic: F = s_1^2/s_2^2

where s_1^2 and s_2^2 and are the sample variances. The more this ratio deviates from 1, the stronger the evidence for unequal population variances.

Significance Level: α

Critical Region: The hypothesis that the two variances are equal is rejected if

$F > F_{\alpha,N_1-1,N_2-1}$ for an upper one-tailed test

$F < F_{1-\alpha,N_1-1,N_2-1}$ for a lower one-tailed test

$F < F_{1-\alpha/2,N_1-1,N_2-1}$ for a two-tailed test

or

$F > F_{\alpha/2,N_1-1,N_2-1}$

Staff/804
Kaufman/3

where F_{α, N_1-1, N_2-1} is the critical value of the F distribution with N_1-1 and N_2-1 degrees of freedom and a significance level of α.

In the above formulas for the critical regions, the Handbook follows the convention that F_{α} is the upper critical value from the F distribution and $F_{1-\alpha}$ is the lower critical value from the F distribution. Note that this is the opposite of the designation used by some texts and software programs.

F Test Example

The following F-test was generated for the AUTO83B.DAT data set. The data set contains 480 ceramic strength measurements for two batches of material. The summary statistics for each batch are shown below.

```
BATCH 1:
   NUMBER OF OBSERVATIONS      =      240
   MEAN                        =    688.9987
   STANDARD DEVIATION          =    65.54909

BATCH 2:
   NUMBER OF OBSERVATIONS      =      240
   MEAN                        =    611.1559
   STANDARD DEVIATION          =    61.85425
```

We are testing the null hypothesis that the variances for the two batches are equal.

H_0: $\sigma_1^2 = \sigma_2^2$
H_a: $\sigma_1^2 \neq \sigma_2^2$

Test statistic: $F = 1.123037$
Numerator degrees of freedom: $N_1 - 1 = 239$
Denominator degrees of freedom: $N_2 - 1 = 239$
Significance level: $\alpha = 0.05$
Critical values: $F(1-\alpha/2, N_1-1, N_2-1) = 0.7756$
$F(\alpha/2, N_1-1, N_2-1) = 1.2894$
Rejection region: Reject H_0 if $F < 0.7756$ or $F > 1.2894$

The F test indicates that there is not enough evidence to reject the null hypothesis that the two batch variancess are equal at the 0.05 significance level.

Questions

The F-test can be used to answer the following questions:

1. Do two samples come from populations with equal variancess?
2. Does a new process, treatment, or test reduce the variability of the current process?

Related

Quantile-Quantile Plot

Staff/804
Kaufman/4

Upper critical values of the F distribution
for ν_1 numerator degrees of freedom and ν_2 denominator degrees of freedom

5% significance level

$$F_{.05}(\nu_1, \nu_2)$$

ν_2 \ ν_1	1	2	3	4	5	6	7	8	9	10
1	161.448	199.500	215.707	224.583	230.162	233.986	236.768	238.882	240.543	241.882
2	18.513	19.000	19.164	19.247	19.296	19.330	19.353	19.371	19.385	19.396
3	10.128	9.552	9.277	9.117	9.013	8.941	8.887	8.845	8.812	8.786
4	7.709	6.944	6.591	6.388	6.256	6.163	6.094	6.041	5.999	5.964
5	6.608	5.786	5.409	5.192	5.050	4.950	4.876	4.818	4.772	4.735
6	5.987	5.143	4.757	4.534	4.387	4.284	4.207	4.147	4.099	4.060
7	5.591	4.737	4.347	4.120	3.972	3.866	3.787	3.726	3.677	3.637
8	5.318	4.459	4.066	3.838	3.687	3.581	3.500	3.438	3.388	3.347
9	5.117	4.256	3.863	3.633	3.482	3.374	3.293	3.230	3.179	3.137
10	4.965	4.103	3.708	3.478	3.326	3.217	3.135	3.072	3.020	2.978
11	4.844	3.982	3.587	3.357	3.204	3.095	3.012	2.948	2.896	2.854
12	4.747	3.885	3.490	3.259	3.106	2.996	2.913	2.849	2.796	2.753
13	4.667	3.806	3.411	3.179	3.025	2.915	2.832	2.767	2.714	2.671
14	4.600	3.739	3.344	3.112	2.958	2.848	2.764	2.699	2.646	2.602
15	4.543	3.682	3.287	3.056	2.901	2.790	2.707	2.641	2.588	2.544
16	4.494	3.634	3.239	3.007	2.852	2.741	2.657	2.591	2.538	2.494
17	4.451	3.592	3.197	2.965	2.810	2.699	2.614	2.548	2.494	2.450
18	4.414	3.555	3.160	2.928	2.773	2.661	2.577	2.510	2.456	2.412
19	4.381	3.522	3.127	2.895	2.740	2.628	2.544	2.477	2.423	2.378
20	4.351	3.493	3.098	2.866	2.711	2.599	2.514	2.447	2.393	2.348
21	4.325	3.467	3.072	2.840	2.685	2.573	2.488	2.420	2.366	2.321
22	4.301	3.443	3.049	2.817	2.661	2.549	2.464	2.397	2.342	2.297
23	4.279	3.422	3.028	2.796	2.640	2.528	2.442	2.375	2.320	2.275
24	4.260	3.403	3.009	2.776	2.621	2.508	2.423	2.355	2.300	2.255
25	4.242	3.385	2.991	2.759	2.603	2.490	2.405	2.337	2.282	2.236
26	4.225	3.369	2.975	2.743	2.587	2.474	2.388	2.321	2.265	2.220
27	4.210	3.354	2.960	2.728	2.572	2.459	2.373	2.305	2.250	2.204
28	4.196	3.340	2.947	2.714	2.558	2.445	2.359	2.291	2.236	2.190
29	4.183	3.328	2.934	2.701	2.545	2.432	2.346	2.278	2.223	2.177
30	4.171	3.316	2.922	2.690	2.534	2.421	2.334	2.266	2.211	2.165
31	4.160	3.305	2.911	2.679	2.523	2.409	2.323	2.255	2.199	2.153
32	4.149	3.295	2.901	2.668	2.512	2.399	2.313	2.244	2.189	2.142
33	4.139	3.285	2.892	2.659	2.503	2.389	2.303	2.235	2.179	2.133
34	4.130	3.276	2.883	2.650	2.494	2.380	2.294	2.225	2.170	2.123
35	4.121	3.267	2.874	2.641	2.485	2.372	2.285	2.217	2.161	2.114
36	4.113	3.259	2.866	2.634	2.477	2.364	2.277	2.209	2.153	2.106
37	4.105	3.252	2.859	2.626	2.470	2.356	2.270	2.201	2.145	2.098
38	4.098	3.245	2.852	2.619	2.463	2.349	2.262	2.194	2.138	2.091
39	4.091	3.238	2.845	2.612	2.456	2.342	2.255	2.187	2.131	2.084
40	4.085	3.232	2.839	2.606	2.449	2.336	2.249	2.180	2.124	2.077
41	4.079	3.226	2.833	2.600	2.443	2.330	2.243	2.174	2.118	2.071
42	4.073	3.220	2.827	2.594	2.438	2.324	2.237	2.168	2.112	2.065
43	4.067	3.214	2.822	2.589	2.432	2.318	2.232	2.163	2.106	2.059
44	4.062	3.209	2.816	2.584	2.427	2.313	2.226	2.157	2.101	2.054
45	4.057	3.204	2.812	2.579	2.422	2.308	2.221	2.152	2.096	2.049
46	4.052	3.200	2.807	2.574	2.417	2.304	2.216	2.147	2.091	2.044

CASE: UE 335
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 805

Exhibits in Support
Of Opening Testimony

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June 6, 2018

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IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 18-047. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 335 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 335
WITNESS: LANCE KAUFMAN

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STAFF EXHIBIT 806

Exhibits in Support
Of Opening Testimony

June 6, 2018

Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97201

October 31, 2002

Public Utility Commission of Oregon
550 Capitol St NE
Suite 215
Salem, OR 97301-2551

Attn: Vikie Bailey-Goggins
Administrator, Regulatory Operations Division

RE: **Advice No. 02-17**

Advice No. 02-17 was filed October 2, 2002, with a requested effective date of November 1, 2002.

PGE is confirming the agreement reached in the ~~September~~ October KW 30, 2002, Public Meeting, to withdraw the following sheets:

First Revision of Sheet No. 125-1
First Revision of Sheet No. 125-2
Second Revision of Sheet No. 125-3
Second Revision of Sheet No. 125-4

All other sheets remain as previously filed.

Please direct any questions regarding this filing to me at (503) 464-7394.

Sincerely,

Sara Cardwell

Sara Cardwell
Manager, Tariff Administration

C: Jack Breen

SCHEDULE 483
TRANSMISSION ACCESS SERVICE
LARGE NONRESIDENTIAL

AVAILABLE

In all territory served by the Company beginning January 1, 2003.

APPLICABLE

To Large Nonresidential Consumers who have chosen the Company's five year transition plan by November 8, 2002. Consumers must have historical usage or have demonstrated that projected usage in 2003 is at least 8,760,000 kWh (1 MWa) from one or more Points of Delivery. Each Point of Delivery must have a Facility Capacity of at least 250 kW. Service under this schedule is limited to the first 300 MWa that applies.

CHARACTER OF SERVICE

Sixty-hertz alternating current of such phase and voltage as the Company may have available

MONTHLY RATE - 2003

For the calendar year 2003, the Monthly Rate for Consumers choosing the Company Supplied Energy option will be the Monthly Rate specified under Schedule 83. The Consumer is limited to the Daily Price Option for Energy. For Consumers choosing Direct Access Service, the Monthly Rate for 2003 will be the Monthly Rate specified under Schedule 583.

FILED TARIFF

CASE: UE 335
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

REDACTED
June 6, 2018

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

A. My name is George R. Compton. I have been employed by the Public Utility Commission of Oregon since March of 2007. I am a Senior Economist (part-time) within the Energy Rates, Finance, and Audits Division. My business address is 201 High St. SE Ste. 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/901.

Q. What is the purpose of your testimony?

A. I address one issue relating to the allocation of costs among customer schedules (rate spread). Specifically, I speak to the reasonableness and implications of the generation reserve margin (GRM) assumed by Portland General Electric (PGE or Company) witnesses Robert Macfarlane and Jacob Goodspeed in their cost of service analyses. I also address one issue with respect to rate design. Specifically, I recommend that the Commission reject PGE's proposal to increase the monthly residential customer charge from $11 to $13.[1]

Q. Are you presenting a substantive exhibit for this docket?

A. Yes. Exhibit Staff/902 shows the effects of relaxing the Company's GRM assumption.

Q. Please provide a brief background on how costs are allocated among customer classes ("rate spread").

[1] PGE/1200 and PGE/1300.

A. The Commission typically uses marginal costs to allocate costs among rate classes. It is a generally accepted economic principle that marginal costs are the relevant costs on which to base pricing decisions because historical costs are 'sunk' costs and cannot be affected by current pricing decisions. [2] The 'marginal cost' of an item is defined as the change in cost that results from a small change in output.[3]

Marginal costs can be "short-run" and "long-run." Long-run incremental costs (LRIC) are the most easily measured and the Commission uses these costs in allocating costs. LRIC is the cost of meeting customer requirements for utility service on a continuing basis as if the system was replicated to serve loads entirely on the basis of the current-priced and current-load-sized equipment.

To determine how much each customer class had contributed to LRIC, it is useful to first represent the electric utility system as performing three basic functions, generation, transmission, and distribution. Generation costs are allocated among the customer classes according to a combination of their contributions to peak demands and their annual, or technology/time-differentiated energy consumption. Transmission costs are also allocated according to the classes' demands during peak periods; and insofar as transmission connections enable access to lower fuel costs, energy use also factors into transmission cost allocations.

---

[2] *In re Portland General Electric Company* (UF 3091), Order No. 74-998, pp. 14-15 (1974 WL 391914).
[3] *In re Portland General Electric Company* (UF 3091), Order No. 74-998, pp. 14-15 (1974 WL 391914).

The two categories of distribution costs are the general distribution costs, such as poles, lines and neighborhood transformation equipment, customer-related costs, e.g., the costs such as the meter, billing, and customer support, and. The former are allocated on the basis of each customer class's shares of the sum of their own peak loads. Customer costs can often be isolated according to their associated customer class and allocated accordingly.

Q. What is your issue in this docket with respect with PGE's allocation of costs among rate classes?

A. Prudent utility management entails having generation capacity reserves sufficient to accommodate some reasonable degree of unscheduled plant outages and extraordinary load spikes. I take issue with using a *target* planning reserve margin for LRIC purposes rather than a reserve margin reasonably expected to be *achieved.* The size of the reserve margin affects how generation costs are allocated among the customer classes.

Topic 1: Reducing the Generation Reserve Margin

Q. Please provide an overview of generation reserve margin portion of your testimony.

A. In conducting its allocation of generation costs, PGE elevates the level of its capacity *as if* a 17 percent planning reserve margin were actually to be achieved. Expanding capacity cost estimates has the effect of shifting costs primarily to the residential class since its loads are relatively less energy-intensive and more demand-intensive than others'. Re-running the PGE cost model by substituting a more realistic 10 percent reserve margin reduces the test period's generation cost allocation to the residential schedule by about $1.3 million, with the offsetting increases felt almost entirely by the industrial schedules.

Q. Please explain the meaning of the production, or generation, reserve margin.

A. Actually there are two meanings, depending upon the context—i.e., whether we're speaking of something achieved or expected to be achieved, or we're speaking in an integrated resource plan (IRP), or planning, context. The former is simply the difference between the load at a particular instant, usually the system coincident peak, and the resources available to meet that load. The reserve margin percentage is simply that difference divided by the load.

The IRP is a planning instrument, and in this context the meaning is somewhat circular. PGE defines the Total Reserve Margin (TRM) as "Total [Existing] Resources plus Capacity Shortage minus Load." The load is typically the system coincident peak since what is wanted to be known is the year's *minimum* margin.[4] The TRM percentage is simply the ratio of the TRM to the Load. I said "circular" because the designated capacity shortage is what the utility deems should be eliminated in order to achieve the desired TRM

[4] The margin is at its minimum when the system is mostly likely to experience an outage because for some reason the load exceeded the available capacity at that time. In the presence of seasonal resources, the minimum reserve margin may occur during the season when resources are beneath the normal peak season.

percentage. In the IRP context what is often referred to as a *planning* reserve margin represents an *aspiration*, i.e., a target objective.[5]

Q. How does the size of the reserve margin affect the allocation of the required revenue requirement among the customer schedules?

A. In the LRIC paradigm employed for utility cost allocation purposes here in Oregon, the reserve margin affects the projected magnitude of generation capacity costs. Expanding capacity costs expands the share of total generation costs borne by customers whose loads are more peak-demand oriented than are other customers'. In sum, a larger reserve margin within the confines of *fixed* generation costs shifts additional costs to the residential class.

Q. You mentioned that PGE has used a 17 percent reserve margin in estimating generation capacity costs. Where did the Company witnesses obtain that figure?

A. They said that the 17 percent figure is found in its 2016 IRP.[6] In other words, it is a target, not necessarily what is expected to be achieved.

Q. Do you find 17 percent extraordinary even as a target?

A. Judging planning reserve margins is outside the areas of my expertise. My exposure is pretty much limited to an awareness of what PacifiCorp has proposed over the years in its IRPs. That figure has been around 13 percent.[7]

---

[5] The proper planning reserve margin can be contentious in the ratemaking context in the presence of a management objective to elevate the ratebase, and a regulatory objective to avoid unjustified costs.
[6] Exhibit 1200/Macfarlane – Goodspeed/2.
[7] *See* Table 5.14 and 5.15 on pages 91 and 92 of PacifiCorp's *2017 Integrated Resource Plan* Volume I, April 4, 2017.

My impression is that 13 percent has been a *goal, or ideal,* that was seldom, if ever, achieved.[8]

Q. Is it your purpose here to dispute the 17 percent figure as a reserve margin *target*?

A. No. What I'm advocating is basing cost allocations upon costs that are likely to be achieved and recognized. Just as Staff's revenue requirement allowances/recommendations are based upon something that reasonably could be achieved, so should cost allocations be made on that same basis. For the purpose of this general rate case, intuitively I could accept a reasonable cost projection made on the basis of an *achieved* reserve margin that was half the Company figure, but in the spirit of compromise I have chosen 10 percent for my model calculations.

Q. Did PGE provide discovery showing its achieved reserve margins for the years since 2008; and if so what were they?

A. Yes. The average reserve margin for the years 2009 through 2016 was **[Begin Confidential]** [redacted] **[End Confidential]**

Q. What does PGE see as its capacity challenges over the next few years?

A. "PGE's capacity need in 2021 [based upon a 17 percent GRM] ... is approximately 819 MW."[9] Benchmark new resources for avoiding those

[8] Keeping up with the rapid growth in the eastern, Rocky Mountain division of PacifiCorp was an ongoing challenge.
[9] PGE's *Integrated Resource Plan,* November 2016, Volume 1, p. 343.

shortfalls are new combined- and single-cycle power plants connected with the Carty premises.[10] Given normal challenges surrounding permitting and construction of large-scale generation facilities, on-time completions become the exception rather than the norm. Accordingly one might expect the Company to be playing catch-up regarding its achieved reserve margin.

Q. What is the effect on residential Schedule 7 of reducing the reserve margin from 17 percent to 10 percent?

A. The savings to that Schedule are approximately $1.3 million for the test period, assuming other factors such as the Company-assumed cost of capital, etc.

Q. Have you prepared an exhibit that shows how that figure was obtained?

A. Yes. Page 1 of Exhibit Staff/902 replicates the PGE model exactly.[11] Page 2 is the identical model apart from the substitution of the 10 percent reserve margin for the Company's 17 percent. Page 3 of Exhibit Staff/902 replicates the PGE Table that shows their recommended dollar and percentage test period annual revenue requirement increases (or decreases) for all of its customer schedules.[12] Page 4 of Exhibit Staff/902 shows those same revenue requirement changes after incorporating Staff's reserve margin adjustment. Subtracting the Page 4 Schedule 7 increase figure, $57,425,264 from the corresponding Page 3 figure, $58,770,406 yields $1,345,142.

[10] *Id.,* p. 346.
[11] *See* UE 335/PGE/1304, Macfarlane – Goodspeed/4.
[12] *See* UE 335/PGE/1302, Macfarlane – Goodspeed/1.

Topic 2: Maintaining the Current Residential Customer Charge

Q. Please provide an overview of residential customer charge portion of your testimony.

A. Staff has long championed limiting the customer charge to the recovery of incremental costs directly caused by customers as individuals. Included in that category are the customer's meter and service line, the local transformer,[13] meter reading, and billing. PGE's current customer charge actually exceeds the sum of those costs by almost $2. To justify a larger customer charge one must include shared costs and costs that are caused in a given month by some, but not all, customers. My position in this case is to not roll back the customer charge to the incremental cost level, but keep it where it is now.

Q. The monthly customer charge is a fixed charge, independent upon usage. What is its purpose?

A. Actually, it serves two purposes, depending upon your point of view and objectives. Staff's purpose is to recover from each customer an estimate of the cost that customer causes by itself. As indicated earlier, those costs are the local transformer, the service line, the meter, and meter reading and billing. Different amounts produced by the Company and found in the indicated exhibits add to the Staff's figure by including costs that are regularly incurred and legitimately recovered but which aren't *individually* caused by a typical

[13] While in more rural areas each customer will have his own dedicated transformer, in dense urban areas a standard transformer may serve as many as six customers. The transformer component of the customer charge is not the cost of a single transformer but the per-customer average of transformer costs based upon the average number of customers per transformer.

customer in a given month. Examples are not insignificant costs of dealing with customers' billing questions and complaints.

Q. Are there conflicting policy objectives that bear on this matter?

A. There are indeed. It is financially advantageous to the utility to collect as much as possible of its total costs via charges that aren't dependent upon the weather, etc.[14] On the other hand, conservation is fostered by having a high volumetric charge as an ongoing price signal to minimize one's utility bill by minimizing one's consumption of electricity. The first objective is served by a large customer charge; the second is served by shrinking the customer charge and increasing the per-kWh and/or per-Kw charges.

Q. Is there an additional rationale besides incenting conservation for shifting cost recovery away from a fixed customer charge and over to a volumetric charge?

A. Yes there is…a value of service rationale for not requiring every customer to pay something beyond the costs that she personally imposes. The health and viability of a utility system depends upon the ability to recover legitimate costs. The theory is that large users get more benefit from the utility system than do small users, and should therefore be expected to pay for more of the general, non-customer-specific expenses.

Q. What are the items that Staff proposes to include with the residential customer charge, and what are their monthly, per customer, incremental costs?

[14] Which means there are cost of capital advantages favoring larger customer charges.

A. That information is contained in the following table. The costs refer to single-phase customers of Residential Schedule 7, and they are per customer. Where applicable, the source refers to the page number of PGE/1304, Macfarlane – Goodspeed. The monthly figure is simply the annual figure divided by 12.

Estimating Residential Marginal Customer Costs

Resource / Function	Annual	Monthly	Source
Transformer & Service	$83.97	$7.00	Page 11
Meters	$19.43	$1.62	Page 11
"Metering"	$0.31	$0.03	Page 16
Billing	$6.00	$0.50	See next Q&A
Total		$9.15	

Q. Before addressing your Billing figure, tell me what is meant by "Metering" and why is the marginal cost so small?

A. "Metering" really means "meter *reading/recording,*" and with PGE's AMI (automatic meter infrastructure) system, on-site, manual meter reading is no longer required.

Q. You just suggested $6.00 as an annual billing cost. What is PGE's billing figure, and what does it include that yours does not?

A. Recall my stated position of only placing into the monthly customer charge the costs that each customer inevitably and individually causes. For billing that could be merely the emailed message, or if the bill is mailed, the cost would be for the paper bill, the envelope, and the postage. I use $0.50 per month as a conservative estimate of those costs.

Q. What major function does the Company include in its customer cost category but does not appear in your table?

A. It is the "Customer" category that appears on Page 18 of the exhibit referenced above. The per-customer annual cost estimate is $24.05, for a monthly figure of $2.00. Included in this category is the department(s) that deals with various customer concerns.

Q. Why was this item not included in your list of candidates for the monthly residential customer charge?

A. It is an example of cost that any particular customer is not expected to impose in a given month.

Q. A noteworthy exhibit for the of Macfarlane-Goodspeed testimony[15] shows the residential Schedule 7 single-phase basic charge[16] *allocation* to be $25.01 per customer per month while the basic charge *pricing* is 13.00 per customer per month, which is what the Company is proposing as the residential customer charge in this docket. Adding the Company's $2 "customer" figure and their larger "billing" figure to the sum of marginal costs in your table, I get a marginal cost figure close to $14 a month. Where does the $25 amount come from?

A. Even though Oregon utilities make rate case applications on the basis of a forecasted test period, what ultimately is recovered are the costs that ultimately are entered into the utilities' accounting books and records, i.e., what we refer to as embedded costs. Embedded costs include a large amount of undepreciated costs relating to capital acquired in past years, along with

[15] PGE/1303, Macfarlane-Goodspeed/3.
[16] PGE refers to the "customer charge" as the "basic charge."

overheads and other kinds of costs such as computer software that don't fit in the marginal cost paradigm. The $25 is a composite of all the *embedded* costs that are placed in the cost categories that appeared in the answers to the Q&A's that preceded this one. The point is that if the customer charge were limited to the recovery of marginal costs, only about half of the embedded costs that fall under the customer-costs-related category would be recovered by that charge.

Q. How does PGE propose to recover the $12 discrepancy between the $25 embedded average costs and its $13 monthly customer charge?

A. In general, cost recovery would be shifted over to distribution charges. The page cited in the previous question shows virtually a dollar-for-dollar increase in the distribution charge portion of the residential revenue requirement. The outcome is shifting from a flat-rate monthly charge to a volumetric, per-kWh charge for recovering much of the customer-related embedded costs.

Q. In keeping the residential customer charge at $11, how does Staff propose to make up the additional discrepancy with regard to related embedded costs recovery?

A. It would be in the same fashion as the Company's, i.e., with an addition to the distribution charge(s).

Q. Does this conclude your direct testimony?

A. Yes.

CASE: UE 335
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

June 6, 2018

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance & Audit Division

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

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah, I also taught Economics part-time for about ten years at BYU.

Prior to my utility regulatory career, I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California.

I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), an Avista General Rate Case (UG 181 and 284), PGE General Rate Cases (UE 197, UE 215, UE 262, and UE 283), PacifiCorp General Rate Cases (UE 210, UE 246, and UE 263), the NW Natural General Rate Case (UG 221), and the Idaho Power General Rate Case (UE 233).

CASE: UE 335
WITNESS: GEORGE R. COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

June 6, 2018

STAFF EXHIBIT 902

SEE ELECTRONIC FILE –

UE 335 Exhibit 902 Compton WP.xlsx

CASE: UE 335
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Opening Testimony

June 6, 2018

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

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

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. I discuss Staff's analysis and recommendation related to environmental licensing services (ELS) costs and load forecast.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/1002, the Company's response to Staff DR No. 238.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ENVIRONMENTAL AND LICENSING SERVICES

Q. What is the Company's proposal for ELS expenses in this filing?

A. PGE proposes inclusion of $2.3 million in administrative and general (A&G) costs for ELS. This amount excludes non-labor budgets for the Portland Harbor Superfund Sites (Portland Harbor), the Natural Resource Damage obligation (NRD), the Downtown Reach portions of the Willamette River (Downtown Reach), and the Harborton Restoration Project (Harborton) (together called "Remediation Projects") that are recovered separately through Schedule 149 as a result of Docket No. UM 1789. They also forecast roughly $9 million dollars for production overhead and maintenance (O&M) costs, $5.7 million of which are non-labor costs.

Q. Please provide background to the Commission decision in Docket No. UM 1789.

A. Commission Order No. 17-071 in Docket No. UM 1789 authorized the implementation of Schedule 149, an automatic adjustment clause (AAC) with the purpose of environmental remediation cost recovery for Portland Harbor and Downtown Reach sites. Schedule 149 includes a Portland Harbor Environmental Remediation Account (PHERA) balancing account for remediation costs determined to be prudent and offsetting remediation revenues from the sale of Discount Service Acre Year (DSAY) credits and insurance proceeds.[1] Since PGE's 2017 general rate case in Docket No. UE

[1] Order No. 17-071, App A., p. 4.

319, PGE has collected no amounts in base rates for environmental remediation costs.

Q How did Staff analyze the amounts included in PGE's test year for ELS costs?

A. Staff reviewed the filing information and work papers looking at historical trends along with the responses to several data requests which provided further information. Staff also compared PGE's filing in this case to information filed in Docket Nos. UM 1789 and UE 319. The following figures show how PGE's test year proposals compare to historical amounts.

Figure 1

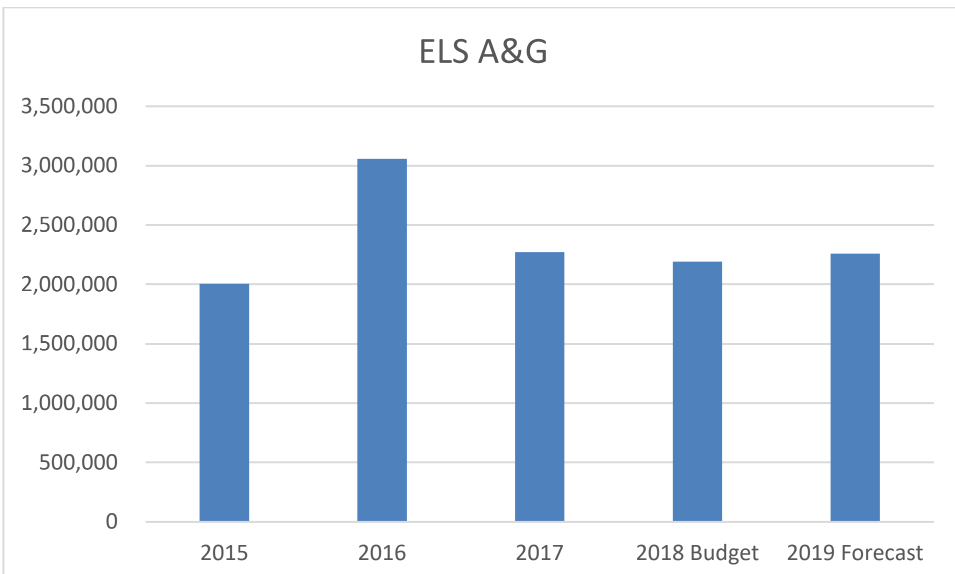

Figure 1 shows that the forecast for 2019 A&G costs remains relatively flat, or more precisely a $9,833 dollar decrease from 2017.

Figure 2

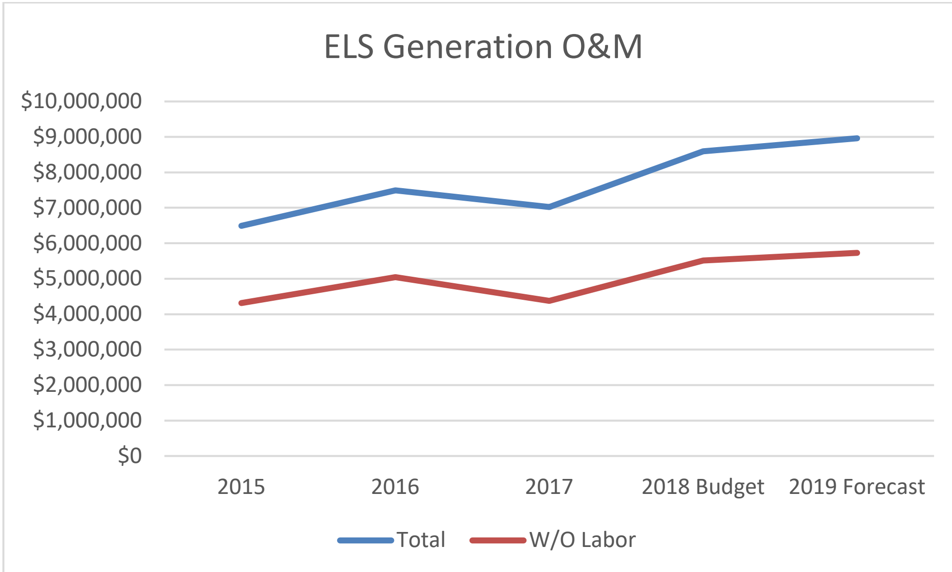

Figure 2 shows that generation related O&M costs have increased on average by 9.5 percent from 2015 through the test year, notwithstanding a drop in 2017 that PGE states that is due to projects delayed by high river run offs, low salmon returns, and fire closures.[2] PGE states the majority of the cost increase is a result of FERC license requirements for its hydroelectric facilities.[3] After reviewing the projects, Staff believes that the basis for the additional costs in 2018 and 2019 is prudent.

Q Does Staff have any concerns regarding PGE's costs for ELS?

A. Yes, although this concern is not the basis of any disallowance.

Figure 3 below looks at historical budget vs actuals for the total ELS division on a department by department basis.

[2] PGE/700, Jenkins – Cristea/11.
[3] PGE/700, Jenkins – Cristea/8-9.

Figure 3

Total ELS Actual/Budget Delta						
ELS Department	2012	2013	2014	2015	2016	2017
172	$348,419	$493,547	$1,097,818	$564,805	$1,917,554	$122,525
841	$718,147	$55,707	$5,010,198	$(810,013)	$(2,060,135)	$(414,487)
842	$ -	$ -	$(2,337,582)	$189,458	$888,112	$51,471
843	$ -	$ -	$(499,685)	$(242,525)	$(144,867)	$(110,299)
844	$ -	$ -	$(936,167)	$(1,014,940)	$(2,417,126)	$(145,825)
Total	$1,066,566	$549,254	$2,334,582	$(1,313,215)	$(1,816,461)	$(496,615)

Of concern to Staff is that particular departments seem to chronically exceed their budget while other departs seem to chronically be over-budgeted for. Department 172 has come in under-budget for six years in a row, by an average of $0.87 million in the last three years. This is the Parks and Recreation Services department, which maintains recreation facilities and sites along the rivers affected by PGE owned dams. Department 842, Eastside Biological Services has also been under budget the last three years. While Department 843, Westside Biological Services has been over budget the last three years. Both of these departments perform similar work on different areas and on different scales. The remaining two departments also have come in over-budget every year since their inception in 2014. Staff recommends that PGE carefully review the budgets of these departments so that costs can accurately be forecasted. Given the tendency for certain departments to come in under or over budget an improvement could be made.

Q. Does Staff have a recommended adjustment for ELS?

A. No, Staff does not have any adjustment at this time.

ISSUE 2. LOAD FORECAST

Q. Please summarize this issue and your recommended treatment.

A. PGE forecasts energy deliveries of 19,041 thousand megawatt-hours (MWh).[4] This is down from 19,124 thousand MWh in the initial filing of PGE's rate case in 2017, and 19,271 thousand MWh from the final calendar year forecast agreed to by parties in the same case. The majority of Staff's concerns are similar to those raised by Staff in previous PGE rate cases. Staff recommends the following:

1. Use of 15-year average weather for normalization; and
2. Removal of PGE's out-board Energy Efficiency (EE) adjustment.

Q. What is PGE proposed treatment for normal weather?

A. PGE proposes to calculate normal weather by projecting a historic trend beginning in 1975.[5] This is a departure from PGE's historic use a 15-year rolling average. The impact of this projection is that PGE forecasts fewer heating-degree days and more cooling-degree days relative to the 15-year average weather.[6]

Q. Have parties considered a trended weather model before?

A. Yes, in Docket No. UE 319 PGE proposed a similar methodology. Staff opposed the use of a trended weather model for several reasons. First, it is not a well-developed methodology in the industry. The table from UE 319 Staff/700, Kaufman/9, shows the weather normalization methodology for all six

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[4] PGE/1100, Riter – Lucas/2, line 2.
[5] PGE/1100, Riter – Lucas/8, lines 16-17.
[6] PGE/1111, Riter – Lucas/1.

of the regulated utilities in Oregon.

Utility	Normal Weather	Source
Avista Utilities	20 Years	Docket No. UG 325 Avista/700 Forsythe/12
Cascade Natural Gas	30 Years	Staff email
Northwest Natural	25 Years	Staff email
PacifiCorp	20 Years	Docket No. UE 323 DR No. 1
Portland General Electric	15 Years	PGE/200 Dammen – Riter/5
Idaho Power Company	30 years (15 for Res CDD)	Staff email

All of the utilities utilize an historic rolling average methodology. Averages that utilize fewer years in their methodology will weight the recent years more heavily. Being the shortest, PGE's methodology should be the most adept at forecasting any upward trend in the weather. PGE states that it is not aware of any other regulated utilities that utilize a trended weather approach in its forecasting.[7]

Second, the main purpose of this forecast is to estimate the next year's energy deliveries. PGE states that capturing a warming trend is particularly important in the long term.[8] Staff's testimony from Docket No. UE 319 concurs:

> *The two models excel at capturing different aspects of evolving weather patterns. [Moving Average] is simpler than the Hinge Fit, but it is more responsive to cyclical patterns. The Hinge Fit model is capable of anticipating a trend in the data, but it does not account for cycles. Both models perform similarly in the short run. However, it is possible that for a long run forecast the Hinge Fit model would perform better.*[9]

When attempting to forecast for next year however, the impact of incorporating a trend is small relative to the uncertainty of what the trend actually is.

[7] PGE/1100, Riter - Lucas /10.
[8] *Ibid.*
[9] UE 319, Staff/700, Kaufman/9.

Third, Staff does not believe that using a trended weather approach will result in a “50/50” load forecast. Meaning the forecast will not have any bias and will be equally likely to forecast too high as too low. Below is Table 2 from PGE/1100, which shows how PGE’s forecast has compared to a group of other forecasts. PGE notes that in general its forecast has outperformed the industry average.

Table 2

Comparison of PGE Forecast Error to Itron Benchmark Survey

	2011		2012		2013		2014		2015		2016	
	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE	Survey	PGE
Residential	1.7%	-0.5%	1.5%	0.0%	1.7%	0.3%	1.5%	1.2%	1.9%	1.5%	1.7%	0.1%
Commercial	1.7%	-0.4%	2.0%	-1.4%	2.1%	-1.9%	1.3%	0.6%	1.6%	0.8%	1.8%	-2.0%
Industrial	3.2%	-0.7%	3.2%	-4.5%	4.4%	-8.8%	3.4%	-0.5%	3.0%	2.8%	3.3%	-2.7%
System	NA	-0.5%	1.6%	-1.5%	1.5%	-2.5%	1.3%	0.6%	1.9%	1.5%	1.6%	-1.4%

However, the table above also shows PGE’s load forecast has historically biased towards under-forecasting, especially compared to benchmark surveys. This is notable given that the benchmark survey better captures the factors that create errors in the forecast. Given the general trend towards greater energy conservation, it is not surprising to see the benchmark survey’s bias in over forecasting load. Just as if one tries to shoot a falling target, the more likely “miss” would be to aim where the target was, not where it is going, thus over-estimating.

The issue we see with PGE’s forecast is that it generally has the opposite problem as the rest of the survey respondents. Whereas the survey respondents generally over-forecasted every year, in 66 percent of the years listed, PGE’s overall forecast is too low. The issue is that a completely unbiased forecast will by nature tend to mirror the average of a large sample of estimators. In the large sample, some will be biased to over-estimate, some will be biased to under-estimate, but with the more estimates used, the more likely the biases will wash out. Further, all of the forecasts will be subject to many of the same forces, meaning that a collection of forecasts that collectively average to a perfect forecast will all show similar error structures when compared to actuals.

So while PGE's forecast has outperformed the market average in a majority of instances over the previous six years, the forecast may only be better suited for current market circumstances and tend to under-forecast total load on average. A move to trended weather, which lowers the overall forecast will not, all else being equal, increase the likelihood of an unbiased estimate when the forecast already shows a potential tendency to under-forecast.

There is little acceptance in the industry of this methodology given the uncertainty regarding the magnitude and sign of a trend and the minimal impact that a trend has in the short term of a rate case forecast. Accordingly, Staff recommends the Company continue the use of a standardized approach using historical average weather for short-term forecasts. Use of a 15 year historical average provides an appropriate balance between relying on normalized historical information and responsiveness to recent weather patterns.

Q. What is the impact of Staff's recommendation?

A. Using 15 year average weather as opposed to PGE's proposed trended weather approach would increase the total energy deliveries forecast by 49.1 thousand MWh.

Q. Please provide a background for the energy efficiency issue.

A. SB 1149 (1999) established a public purpose charge that funds various public purposes including energy efficiency programs. In 2001, the Energy Trust of Oregon (Energy Trust) began administering energy efficiency programs in PGE's service territory. According to the Company, the energy-use reductions ("savings") from the SB 1149-funded programs were expected to be similar to the PGE-implemented programs they replaced.[10] As such, PGE made no adjustment to its load forecast methodology due to SB 1149.

In 2007, SB 838 was passed, which allowed IOU's to include in its rates the costs of funding cost-effective energy conservation measures incremental to those paid for by the public purpose charge. PGE states that SB 838 effects were expected to be significantly greater than the savings levels seen in prior years.[11] Based on this expectation, PGE included an out-of-model adjustment in Docket No. UE 197 (2009 test year) for SB 838-based energy efficiency savings. PGE has continued to utilize an out-of-model adjustment to estimate the incremental impact of SB 838 savings and decrement the load forecast. In Docket No. UE 283 testimony filed in 2014, Staff explained:

> *[PGE's] energy efficiency adjustment forecast modifies the forecast to account for new energy efficiency measures. This adjustment only accounts for energy efficiency measures related to SB 838. The*

[10] Exhibit Staff/1002.
[11] *Ibid.*

> *Energy Trust of Oregon's (ETO) forecast for 2014 and 2015 energy efficiency measures is shaped into monthly incremental savings. The monthly incremental savings are than aggregated into monthly cumulative energy savings. These savings are then allocated to each forecast group based on a historic pattern. The forecast group's cumulative energy efficiency savings are removed from the group's price adjusted forecast.*[12]

Q. Have parties considered PGE's Energy Efficiency adjustment before?

A. Yes, Staff has voiced concerns over the adjustment many times. In Docket No. UE 283 Staff noted that, "PGE provides no empirical justification for the Company's choice to ignore all SB 1149 measures and fully adjust SB 838 measures."[13] In Docket No. UE 294 Staff noted that "PGE's energy efficiency adjustment double counts as the base forecast includes a background level of energy efficiency."[14]

As noted earlier the Company states that the savings from SB 1149, which became effective in October 2001, are assumed to be embedded in the forecast trend.[15] However, the savings associated from SB 838, which became effective in 2007, are not.[16] Staff does not believe this assumption is correct. With every subsequent year, the degree to which the savings from SB 838 are in fact embedded in historical deliveries data grows. Accordingly, the forecast incrementally drops for every year that includes actual SB 838 effects, and then drops again due to the out-of-model adjustment made by PGE. This is the double counting Staff was referring to in UE 294.

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[12] UE 283 Staff/300, Kaufman/15, lines 3-11.
[13] UE 283 Staff/300, Kaufman/16, lines 9-11
[14] UE 294 Staff/500, Fonner/10, lines 16-17.
[15] Exhibit Staff/1002.
[16] *Ibid.*

In order to evaluate the actual degree to which SB 838 impacts were being captured in the data, Staff reviewed PGE workpapers. Staff found that all of PGE's energy forecasts have January 1, 2005 as a starting date for data. So 11.5 out of 12.8 years have data that includes the effect of both SB 838 and SB 1149. To test the need for an out-board adjustment to account for SB 838 effects, Staff attempted to estimate the effect of SB 838 EE with an in-model variable in UE 319[17]. The result was that the SB 838 EE impact was small and not statistically significant. From this result, Staff surmised that the data already captured the impact of EE expenditures.

The results of Staff's modeling exercise make sense given that the double counting Staff first explained in UE 294 occurs in roughly 89 percent of the total dataset in each of the forecasts. The data which the Company already uses, provides sufficient information in the model via a standard trend to predict an EE impact, so extra information about EE is superfluous. It does not make sense to believe that the impact of SB 1149 is captured in the data, but SB 838, which is in effect for the vast majority of the data, is not captured. This could also explain why PGE's forecasts have historically produced lower estimations than the industry average. There is also precedent for dropping EE adjustments, as Avista's most recent GRC forecast omitted any EE variable or adjustment.

Q. What is Staff's recommendation for the EE adjustment?

[17] UE 319 Staff/1300, St. Brown/17-18.

A. Staff does not believe that the out-of-model adjustment is necessary or justified. SB 838 has been in-effect for all but roughly one year of the thirteen years of data used to forecast. Removal of the EE adjustment would increase the total energy deliveries forecast by 300.6 thousand MWh.

Q. What is the combined effect of Staff's recommended adjustments?

A. Utilizing 15 year average weather for normalization and removal of the EE adjustment would increase PGE's adjustment by 349.7 thousand MWh, the resulting forecast would be 19,391 thousand MWh test year energy deliveries. This represents a 0.6 percent increase from the forecast agreed to at the conclusion of UE 319.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 335
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualification Statement

June 6, 2018

WITNESS QUALIFICATION STATEMENT

NAME: Scott Gibbens

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Energy Rates, Finance and Audit

ADDRESS: 201 High St. SE Ste. 100
Salem, OR 97301-3612

EDUCATION: Bachelor of Science, Economics, University of Oregon
Masters of Science, Economics, University of Oregon

EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UE 335
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support
Of Opening Testimony

June 6, 2018

May 1, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to OPUC Data Request No. 238
Dated April 18, 2018

Request:

Please refer to PGE/1100, Riter – Lucas/6, lines 10-12. Did previous iterations of PGE's forecast methodology include separate adjustments for the effect of SB 1149? If so, when was the adjustment changed? Why does PGE believe SB 1149 effects to be implicit in the data but SB 838 effects coming five years after are not?

Response:

No, previous vintages of PGE's forecast did not include a separate adjustment for the effect of SB 1149. Prior to SB 1149, PGE implemented cost effective energy efficiency programs as identified by its Integrated Resource Planning process. The historical trajectory of these savings, - which was replaced by the SB 1149-funded programs in 2001, was fairly stable over time. For this reason, those savings were not seen as "new" even though the funding mechanism and implementation structure changed. These savings were assumed to be embedded in historical deliveries data and therefore, PGE did not separately adjust for SB 1149.

Programs associated with SB 838 were expected to go into effect in mid-2008 ramping to levels significantly larger than the savings levels seen in prior years. In UE-197 (PGE's General Rate Case, 2009 test year, load forecast created in late 2007) PGE included an adjustment for energy efficiency savings associated with the new (at that time) funding mechanism to account for the incremental increase in savings associated with these measures. Since the early years of SB 838, the savings levels associated with the funding mechanism have increased significantly. As such, PGE has found it to be appropriate to continue to adjust its forecast to explicitly account for the effect of these incremental savings on its energy deliveries forecast. PGE's load forecast methodology continues to assume the ETO savings funded by SB 1149 are embedded in the forecast trend and the ETO savings funded by SB 838 are incremental savings above what is embedded in the forecast trend and PGE has found that these models perform well.

CERTIFICATE OF SERVICE

UE 335

Parties have waived paper service for this filing.

I certify that I have this day served the foregoing document electronically (via Huddle) pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 6th day of June, 2018 at Salem, Oregon.

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UE 335
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