BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 319

Revenue Requirement

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Alex Tooman, Ph.D.
Rebecca Brown

February 28, 2017

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I. Introduction

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

A. My name is Alex Tooman. I am a project manager for PGE. I am responsible for the development of PGE's revenue requirement forecast and other regulatory analysis.

My name is Rebecca Brown. I am a senior analyst assisting Alex Tooman in the development of the revenue requirement.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present PGE's 2018 revenue requirement for base business of $1,883.3 million.

Q. What increase in revenue requirement does PGE request beginning January 1, 2018?

A. PGE requests a base business increase of $99.9 million or 5.6% effective January 1, 2018. This increase is relative to the revenues we expect based on 2016 prices, approved in UE 294. This revenue requirement will allow PGE an opportunity to earn a 7.46% rate of return that includes a 9.75% return on average common equity (ROE) of 50% in 2018. PGE Exhibit 201, columns 1 through 3, summarizes the development of PGE's 2018 revenue requirement for base business. In addition to presenting this integrated (bundled) revenue requirement, we also present and discuss our unbundled revenue requirement in Section IX.

Q. What mitigating actions did PGE take to help limit the size of the requested increase in this filing?

A. As described in PGE Exhibit 100, to reduce the price impact on customers, we adjusted the revenue requirement by:

1. Reducing our request related to incentive compensation costs;

2. Removing 50% of certain layers of Directors & Officers (D&O) insurance;
3. Requesting a return on equity at the lower portion of the range supported by PGE's expert witness.

A. PGE Result if No Price Increase is Authorized

Q. In the absence of a price increase, what is PGE's expected regulated ROE for 2018?

A. Without a price increase, we would expect PGE's ROE to be approximately 7.2% in 2018, lower than the authorized ROE of 9.6%.

B. Structure of the Case

Q. Please summarize PGE's 2018 revenue requirement.

A. Table 1 below summarizes PGE's 2018 revenue requirement by major category and provides a comparison to the results of UE 294. We also list the PGE testimony that addresses each specific cost category.

Table 1

Revenue Requirement Summary
($ in millions)

Rev Req Category	UE 294 Approved	2018 Budget	Exhibit	No.
Sales to Consumers	$1,864.6	$1,883.3	Rev Req	200
Other Revenue	$ 26.6	$ 25.8	Rev Req	200
NVPC	$ 531.6	$ 353.6	Power Costs	300
Production O&M	$ 156.1	$ 159.8	Production	700
Transmission O&M	$ 14.3	$ 14.3	T&D	800
Distribution O&M	$ 94.5	$ 120.2	T&D	800
Customer Service	$ 79.3	$ 82.3	Customer Svc.	900
A&G	$ 151.4	$ 172.1	Corp. Support	600
Depr. & Amort.	$ 330.5	$ 377.3	Rev Req	200
Other Taxes	$ 126.1	$ 127.2	Rev Req	200
Income Taxes	$ 74.1	$ 159.7	Rev Req	200
Operating Income*	**$ 333.4**	**$ 342.7**		
Return on Equity	9.6%	9.75%	Return on Equity	1100

** May not sum due to rounding*

Q. Please describe Operating Income as used in Table 1 above.

A. Operating Income consists of a return to the providers of capital to PGE, both equity and debt. The costs of obtaining capital are discussed in PGE Exhibits 1000 and 1100.

Q. How did you develop the 2018 revenue requirement?

A. We developed the revenue requirement based on PGE's 2017 budgets, which were originally based on UE 294 prices as authorized by Commission Order No. 15-356. The 2017 budgets were escalated for inflation to 2018 and adjusted for known and measureable changes.

Q. What rates did you use to escalate the 2017 budget to 2018 test year?

A. We applied the following escalation rates to the 2017 budget:

- 3.10% average rate for all labor (at applicable effective dates[1]).
- 3.11% for outside services (cost elements [CE] 1502, 1602, 2200, and 2300), effective January 1.
- 1.66% for direct materials (CE 2101 and 2110), effective January 1.
- 2.39% for employee business expense (CE 2400 and 2701), effective January 1.

Q. What are the sources of these escalation rates?

A. For outside services, direct materials and employee business expense, we use escalation rates from the Global Insights, Long-term Forecast dated August 2016. Wage escalation is based on the forecast of compensation costs described in PGE Exhibit 400.

Q. What comparison with the 2018 test year costs does PGE make in the testimonies generally?

[1] March 1 for bargaining employees and April 1 for non-bargaining employees.

A. We compare our forecast of 2018 test year costs to 2016 actuals. We do this because 2016 represents PGE's most recent full year with actual results. The changes between 2016 and 2018 in this filing will be analyzed on an average annual basis.

Q. Did you adjust PGE's 2018 revenue requirement to reflect previous pricing decisions and other regulatory policies?

A. Yes. We made several regulatory adjustments, listed in Table 2 below.

Table 2
Regulatory Adjustments
($ in millions)

Category	O&M	Rate Base
Retail Services	$(0.1)	$(0.9)
Charitable Contributions	$(1.9)	
State & Federal Lobbying	$(1.0)	
MDCP	$(4.7)	
SERP	$(1.4)	
Image Advertising	$(0.7)	
Total Adjustments	**$(9.8)**	**$(0.9)**

Q. Please explain these regulatory adjustments.

A. Following is a brief summary:

- Retail services: removed the revenue requirement related to amounts allocated to PGE's retail operations;
- Charitable contributions: excluded the entire $1.9 million from cost of service;
- State and federal lobbying: excluded the entire $1.0 million from cost of service;
- Managers' Deferred Compensation Plan (MDCP): removed the entire $4.7 million from cost of service;
- Supplemental Executive Retirement Plan (SERP): removed the entire $1.4 million from cost of service; and
- Corporate image advertising: removed the entire $0.7 million from cost of service.

II. Other Revenue

Q. What is PGE's 2018 forecast of Other Revenue?

A. PGE forecasts 2018 Other Revenue of $25.8 million. This compares to 2016 Other Revenue of $26.7 million. The decrease is primarily attributable to joint pole revenue, which declines from 2016 actuals because:

- 2016 actuals reflect approximately $1.2 million in revenue for a short-term, high-speed fiber deployment project that did not continue beyond 2016.
- There is an overall decline in PGE's annual pole attachment rental rate.

Q. What are the sources of Other Revenue?

A. The primary sources of Other Revenue are rent of electric property, transmission revenue, joint-pole revenue, steam sales revenue, and ancillary service revenue. PGE Exhibit 202 provides additional detail on the sources and amounts of Other Revenue.

Q. Did you make any adjustments related to Other Revenue for the 2018 test year?

A. Yes. We adjusted the 2018 forecast of transmission revenues received from Energy Service Suppliers (ESS). The adjusted amounts reflect PGE's current Open Access Transmission Tariff rate and the forecasted ESS activity for 2018.

III. Depreciation

Q. What was used for the 2018 test year book depreciation expense?

A. Normalization rules in the Internal Revenue Code, Section 168(i)(9) require consistency in the calculation of four items for ratemaking purposes. Two of the four items are tax expense and book depreciation expense. The other two items are in rate base: accumulated book depreciation and accumulated deferred income taxes. Because, PGE established its rate base as of December 31, 2017, we used 2017 depreciation in the calculation of all four items.

Q. Does 2017 depreciation accurately reflect the 2018 expense?

A. By itself, no. Because 2017 depreciation will only reflect partial year depreciation for all 2017 plant closings, 2017 depreciation will be less than 2018 depreciation, which will reflect a full year of depreciation for those same assets (assuming no additional plant closings in 2018). In order to adjust for this effect, PGE annualized the 2017 depreciation expense for 2017 plant closings. We then reduced that amount to account for the fact that PGE's declining balance method results in a 2018 depreciation expense that would not be as high as that calculated with the full annualization effect. The net result is that the test year depreciation is based on 2017 expense (to meet IRS normalization requirements) but has an adjusted annualization so that PGE does not under-collect or over-collect depreciation expense relative to expected 2018 depreciation expense. As noted above, the expected 2018 depreciation expense does not reflect any 2018 closings. For simplicity, we refer to the test year depreciation as 2018 depreciation expense.

Q. What is PGE's estimate for 2018 depreciation expense?

A. We estimate $317.4 million in depreciation expense for 2018. PGE Exhibit 203 summarizes the 2018 depreciation expense by plant type and provides a comparison to 2016 actuals.

Q. Is PGE proposing a new depreciation study as part of this rate case?

A. Yes. PGE filed the new depreciation study on December 23, 2016. It is docketed as UM 1809.

Q. What is the difference between the previous depreciation study (Docket No. UM 1679) estimate for 2017 depreciation expense and the current depreciation study estimate (Docket No. UM 1809)?

A. The methodology proposed in the current depreciation study leads to a $2.2 million increase in depreciation expense in 2017.

Q. How does PGE's 2018 depreciation expense forecast compare to 2016 actuals?

A. After adjustments, total forecasted depreciation for 2018 reflects a $40.1million increase over 2016 actuals.

Q. What are the primary drivers for the increase?

A. The primary drivers of the increase in depreciation expense are listed below.

- $4.4 million for the Colstrip generation plant to reflect the change of depreciable life from 2042 to 2030 as specified in Oregon Senate Bill 1547, Section 1.
- $6.8 million in the Carty generation plant, which had only partial year depreciation in 2016 but a full year in 2018. Customer prices, however, already reflect the full year of Carty 2016 depreciation expense in accordance with Commission Order No, 15-356.
- $4.0 million in other thermal generating plants.
- $4.7 million in wind and hydro generation resources.
- $6.4 million in distribution.
- $3.5 million in general plant.

IV. Amortization

Q. What is amortization?

A. Amortization, like depreciation, is a means to allocate the cost of an asset over its useful life. Amortization relates to intangible assets, such as computer software and regulatory assets. As with depreciation expense, the unamortized balance of the associated assets generally appears in rate base and earns a return at the allowed rate. Because amortization is also subject to tax normalization principles, we calculated the 2018 test year amortization expense based on the adjusted annualized 2017 amortization similar to depreciation.

Q. Please summarize PGE's 2018 amortization expense.

A. PGE Exhibit 204 details the total 2018 amortization expense of $68.3 million, which we summarize in Table 3 below.

Table 3
Amortization
($ in millions)

Amortization Item:	2016 Actuals	2018 Forecast
Software Amortization	$ 35.7	$ 47.0
Other Intangible Amortization	$ 8.4	$ 9.3
Trojan Decommissioning	$ 3.5	$ 3.5
Trojan Fuel Settlement	$ (16.3)	$ 0.0
Other Reg Debit Amortization	$ 9.4	$ 8.8
Other Reg Credit Amortization	$ 0.2	$ (0.2)
Total Amortization*	**$ 40.8**	**$ 68.3**

* *May not sum due to rounding*

Q. Please explain the amortization of software included in PGE's 2018 amortization expense.

A. Total software amortization is approximately $47.0 million. This cost relates to capitalized software, which is typically amortized over a 5-year period. The exception to this period is the 2020 Vision program (including the Financial System replacement project, Maximo mobile scheduling, Outage Management System, Graphic Work Design, and Geographic Information System), which is amortized over a 10-year period.

Q. Why is software amortization $11.3 million higher in 2018?

A. The increase is due to the software investment that closed to Plant in Service during 2016, which results in partial year amortization in 2016 and full year amortization in 2018, as well as additional software investment in 2017. The larger software projects closing in 2016 and 2017 include the Energy Trading & Risk Management Solution, software upgrades to move customers to lower cost self-service options (Web Fitness-Remove Self Service Barriers), Knowledge Management & Governance Software for Customer Service Operations, and software for hosting the Western Energy Imbalance Market (discussed in PGE Exhibit 300, Section III, part C).

Q. Please describe Other Intangible amortization.

A. Other Intangible amortization includes hydro relicensing amortization and miscellaneous other intangible plant amortization. For hydro relicensing, this represents the recognition of annual costs associated with non-construction projects that have closed to plant in service. Generally, these costs are amortized over the life of the new license.

V. Income Taxes, Taxes Other Than Income, and Fees

A. Income Taxes

Q. What is PGE's 2018 estimate of income taxes?

A. PGE's 2018 test period income tax expense forecast is $159.7 million. PGE Exhibit 205 details the test year calculations of income tax expense and provides a comparison to previously authorized 2016 income tax assumptions. This compares to the 2016 utility income tax expense of $74.1 million based on prices approved by Commission Order No. 15-356. The increase in 2018 test year income tax expense compared to current prices reflects: 1) an increase of pre-tax book income; and 2) federal production tax credits (PTC) being treated as a variable, rather than fixed, component of PGE's forecast, consistent with the provisions of Oregon Senate Bill 1547, Section 18b.

Q. Is the change in PTC treatment new for 2018?

A. No. PGE first implemented this change in Docket No. UE 308, PGE's 2017 Net Variable Power Cost filing, which was subsequently approved by Commission Order No. 16-419.

Q. What method did you use to establish estimated income tax expense for the 2018 test year?

A. We use the "stand-alone" method to determine the test year income tax expense. This method uses as inputs only those costs and revenues included in our requested test year revenue requirement to determine the income tax expense for the test year. The Commission has traditionally used this approach to determine the income tax expense in test year price development. Further, since PGE's operations consist of nearly 100% regulated utility activity, this method also conforms to ORS 757.269, which specifies how income taxes are treated for developing retail prices.

Q. Are any state and federal tax credits included in your estimate of income tax expense for 2018?

A. No. As discussed above, federal PTCs are now reflected as part of PGE's net variable power costs. Additionally, all of PGE's state tax credits have been utilized and there are none currently forecasted for 2018.

B. Taxes Other Than Income and Fees

Q. What is PGE's 2018 estimate of Taxes Other Than Income and Fees?

A. As shown in PGE Exhibit 206, total Taxes Other Than Income are $127.2 million for 2018. This compares to 2016 actual costs of $118.2 million. The primary individual sources of increased costs from 2016 actuals to the 2018 test year are:

- Franchise Fees: from $43.1 million to $47.9 million; and
- Payroll Taxes: from $13.5 million to $16.1 million.

1. Franchise Fees

Q. Why have franchise fees increased from 2016 to the 2018 test year?

A. PGE updated the franchise fee rate to reflect the three-year average of 2014-2016 actuals. Although the franchise fee rate dropped slightly from 2.547% (UE 294) to 2.545%, overall, franchise fees increase because PGE's requested revenue requirement increases.

2. Payroll Taxes

Q. How does PGE estimate payroll taxes?

A. PGE estimates payroll taxes by applying an approximate 12.2% payroll tax rate to total wages and salaries. We allocate a portion of payroll tax cost to capital consistent with the allocation of overall capitalized wages and salaries.

Q. Why have payroll taxes increased from 2016 to the 2018 test year?

A. Payroll taxes increase as wages and salaries grow between those years as described in PGE Exhibit 400.

3. Property Taxes

Q. Please describe PGE's obligation to pay property taxes?

A. PGE owns property in three states: Oregon, Montana (Colstrip plant and related transmission) and Washington (Tucannon River Wind Farm and KB Pipeline for gas used at the Beaver plant). As a result, PGE is obligated to pay property taxes in each of these jurisdictions.

Q. How do these jurisdictions assess property taxes on PGE?

A. Rather than each individual county assessing property tax, Oregon, Montana, and Washington "centrally assess" PGE's property using a unit approach. This unit approach is required by state statutes because the properties are considered a single economic unit and system assets are thoroughly integrated in operation and construction. For example, a piece of wire cannot be valued without looking at its relationship to the entire unitary system. Each state uses a combination of three approaches to determine value: 1) Cost, 2) Income, and 3) Comparable Sales. The result of each approach is considered and weighed by each respective state assessor in determining a correlated system value. The goal of this valuation process is to assess PGE's operating system as closely as possible to its real market value on January 1st of each year.

Q. Is PGE including property tax savings incentives related to major construction projects?

A. Yes. Similar to prior years, PGE has included tax savings related to Strategic Investment Program (SIP) property tax abatement agreements for Biglow Canyon, Port Westward II, and Carty.

Q. What is PGE's forecast for 2018 property taxes?

A. PGE has forecast approximately $60.7 million of 2018 property taxes compared to 2016 actuals of $59.2 million. The increase is primarily a result of the Carty plant being placed into service midway through 2016, along with other increases in plant in service.

VI. Rate Base

Q. What is PGE's 2018 rate base and what does it include?

A. PGE is using year-end 2017 rate base to preclude assets that are not in service prior to January 1, 2018, when base prices go into effect. As of December 31, 2017, PGE is expecting rate base to be approximately $4594.1 million. PGE Exhibit 207 provides the details of the 2017 rate base, which includes PGE's investment in plant in service, net of accumulated depreciation, and accumulated deferred income taxes (ADIT)[2]. In addition, the rate base includes Fuel and Materials Inventory, Miscellaneous Deferred Debits and Credits, and Working Cash.

Q. How does PGE's 2017 rate base compare to amounts approved in UE 294?

A. PGE Exhibit 208 shows that the rate base approved in UE 294 is $4,440.2 million and that PGE's 2017 rate base reflects an increase of $153.9 million. The increase is primarily attributable to the growth in distribution plant in service as discussed in PGE Exhibit 800.

Q. Did you include the prepaid pension asset in rate base?

A. No. Based on Commission Order No. 15-226 (Docket No. UM 1633) we excluded the prepaid pension asset and the associated deferred tax liability from PGE's rate base.

Q. What is the working cash total added to rate base in this filing?

A. Applying the 3.628% working cash factor to total forecasted operating expenses in 2018 of $1,566.5 million yields the working cash total in rate base of approximately $56.8 million. This amount is shown in PGE Exhibit 201.

[2] ADIT is also calculated based on year-end 2017 amounts, consistent with IRS Normalization principles.

VII. Carty Update

Q. Please summarize the ratemaking relief PGE sought for Carty in Docket No. UE 294.

A. In UE 294, PGE requested that prices recovering Carty's net revenue requirement become effective shortly after a PGE officer provided an attestation that Carty was placed in service.

Q. Did Commission Staff analyze the prudence of PGE's actions related to Carty?

A. Yes. Staff analyzed the prudence of PGE's actions related to Carty from two perspectives. First, Staff analyzed the consistency of Carty with previous integrated resource plans (IRPs) and request for proposals (RFPs). Second, Staff analyzed the prudence of Carty as of the date when the Company decided to proceed with the project.[3]

Q. What was the outcome of UE 294, with respect to Carty?

A. On November 3, 2015, the Commission issued Order No. 15-356 approving settlements reached in UE 294. With respect to Carty, the approved settlements stipulate PGE's decision to construct Carty was prudent. The approved settlements also identify the conditions for which Carty's prudently incurred costs and benefits would be included in customer prices when Carty begins providing service to customers. The conditions include:[4]

> i. For determining rates in this docket only, the gross plant for Carty, including the Grassland Switchyard, will be $514 million… If Carty capital costs are higher than the designated amount, PGE may not recover those costs through the Carty tariff rider. However, PGE will not be bound to the original $514 million estimate in subsequent rate proceedings. If PGE seeks to recover any additional amounts in a subsequent general rate filing, PGE must demonstrate the prudence of such additional costs.
>
> ii. PGE will file an attestation by an officer when the Carty plant is placed in service.

[3] See UE 294 Staff Exhibit 1700, page 6.
[4] Commission Order No. 15-356, Appendix A, pages 4 and 5.

iii. If the Carty Generating Station is not completed and in service by July 31, 2016, PGE will need to file a new ratemaking request seeking the inclusion of the Carty costs in rates, inclusive of Grassland Switchyard.

Q. Did PGE place Carty into service by July 31, 2016?

A. Yes. PGE placed Carty into service on July 29, 2016.

Q. Are Carty capital costs higher than $514 million in PGE's 2017 year-end rate base?

A. Yes. The Carty capital costs are approximately $521.7 million in PGE's year-end 2017 rate base.

Q. Why are the Carty capital costs higher than $514 million?

A. Because PGE did not place Carty into service until July 29, 2016, PGE accrued approximately two months of additional financing (i.e., AFDC) on the capital costs that were determined to be prudent through Commission Order No. 15-356. The $514 million capital cost forecast used by PGE in UE 294 assumed that Carty would be in-service by mid-May 2016. Thus, the additional costs included in this case represent timing only and are fully consistent with the construction costs previously approved.

Q. What are the overall construction costs to build the Carty facility?

A. PGE expects construction costs to total between $635 and $640 million, excluding certain lien claims totaling $17 million that PGE is challenging.

Q. Does this rate case include the additional construction costs associated with Carty?

A. No. As explained earlier, PGE included only the original cost estimate of $514 million, adjusted for AFDC for the time value difference between the actual online date in July 2016 and the originally expected online date in May 2016.

Q. Is PGE continuing to diligently pursue payment from Liberty Mutual and Zurich American Insurance Company pursuant to a performance bond as described in PGE's SEC financial statement disclosures?

A. Yes. For a more complete update on the status of these legal matters, see PGE's 2016 10-K (Part II, Item 8, Note 17).

VIII. Customer Engagement Transformation (CET)

Q. Please provide an update on PGE's Customer Engagement Transformation (CET) project.

A. PGE continues to work toward the completion of CET, which has been a multi-year program consisting of 24 projects and culminating in 2018 with the replacement of two legacy customer systems: Customer Information System and Meter Data Management System.

Q. Are you including the revenue requirement for the systems closing in 2018 in your request?

A. No. PGE is not including the 2018 CET projects in customer prices at this time. Capital costs for CET will be presented in a future rate making proceeding. PGE Exhibit 900 provides a detailed update of CET.

IX. Unbundling

Q. Have you unbundled the 2018 revenue requirement pursuant to OAR 860-038-0200?

A. Yes. PGE Exhibit 209 summarizes the results of unbundling the integrated revenue requirement, as required by OAR 860-038-0200, into the required functional areas or revenue requirement categories. Table 4 below summarizes the base unbundled revenue requirement for 2018.

Table 4
Unbundled Revenue Requirement
($ in millions)

Production	$1,090.7
Transmission	$ 28.5
Distribution	$ 635.8
Ancillary	$ 4.9
Metering	$ 8.4
Billing	$ 63.0
Other Consumer Services	$ 52.0
Total*	**$1,883.3**

** May not sum due to rounding*

The sum of the unbundled revenue requirement for these services equals the integrated revenue requirement as presented in PGE Exhibit 201 columns 1 through 3.

Q. How did you develop the revenue requirement after unbundling costs and rate base?

A. We used traditional revenue requirement methodology – recovery of cost plus a return on rate base – to calculate the revenue requirement for each unbundled service in accordance with OAR 860-038-0200(9)(d).

Q. How did you unbundle PGE's 2018 expenses and Other Revenue?

A. We unbundled expenses and Other Revenue by analyzing each account within those categories. First, we determined which accounts could be directly assigned to one of the functional categories listed in Table 4 above. Second, we evaluated those accounts that could not be clearly assigned to determine a basis for allocation.

Q. Were most of the expense and Other Revenue accounts assigned or allocated?

A. The majority of accounts have a direct relationship with a single functional area and we assigned these accounts based on OAR 860-038-0200(9)(b)(A) through (E). The largest category of allocated costs is administrative and general (A&G), which we allocated to the functional areas based on labor dollars for those areas. Other costs, such as property taxes, and payroll taxes, relate to factors such as net plant or labor. We allocated these costs based on the respective share of those factors per functional area in accordance with OAR 860-038-0200(9)(c)(B)(i) through (ii). For other expenses, such as depreciation and amortization, we "functionalized in the same manner as the respective plant accounts" – see OAR 860-038-0200(9)(c)(A).

Q. Did you allocate any expense or Other Revenue to retail or non-utility?

A. Yes, for retail and no for non-utility. First, we allocate costs to retail activities based on assets allocated to retail. Second, while we forecast labor costs in non-utility, "below-the-line" accounts, these accounts already receive allocations for corporate governance (i.e., A&G/Support costs) and service providers (i.e., facilities, Information Technology, and print/mail services) based on that labor. Therefore, unbundling A&G (or other support costs) to non-utility accounts would apply these costs twice.

Q. How did you unbundle rate base?

A. There are two categories of rate base that we evaluated for unbundling: 1) plant in service with associated depreciation reserve, accumulated deferred taxes, and accumulated investment tax credits; and 2) other rate base. For plant in service, we assigned most assets and their associated contra accounts in accordance with OAR 860-038-0200(9) (a) (A) through (F). These assets clearly relate to specific functional areas (e.g., thermal and hydro generating plants; transmission towers and conductors; distribution poles, conductors, substations, transformers, and service drops). Some general and intangible plant was directly assigned, but the majority of these categories consist of many smaller assets without a clear functional attribute so we allocated them based on labor.

Q. How did you unbundle other rate base?

A. We assigned or allocated other rate base using the criteria established in OAR 860-038-0200(9)(a)(G). Specifically, we evaluated other rate base on an account-by-account basis and directly assigned where applicable (e.g., fuel inventories are assigned to Production). For other categories, we allocated costs on an appropriate basis (e.g., deferred credits related to post-retirement medical and life insurance are allocated based on labor).

Q. Did you assign franchise fees to the distribution function?

A. Yes. Pursuant to OAR 860-038-0200(9) (c) (B) (i) (IV), PGE assigned franchise fees directly to the distribution function. We also assigned write-offs for uncollectibles directly to the distribution function.

X. Qualifications

Q. Mr. Tooman, please state your educational background and experience.

A. I received a Bachelor of Science degree in Accounting and Finance from the Ohio State University. I received a Master of Arts degree in Economics and a Ph.D. in Economics from the University of Tennessee. I have held managerial accounting positions in a variety of industries and have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. Finally, I have worked for PGE in the Rates and Regulatory Affairs department since 1996.

Q. Ms. Brown, please state your educational background?

A. I received a Bachelor of Science degree in Accounting from the University of Nevada-Reno and a Master of Business Administration with an emphasis in Finance from the University of Wyoming. I am a Certified Public Accountant. I have worked at three state commissions (Wyoming, Texas and Oregon) totaling 12 years of direct regulatory experience. I also worked at PacifiCorp for nearly three years in Corporate Accounting and have been with PGE since 2007 (in the Rates and Regulatory Affairs department for over seven years), totaling over 25 years of experience.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
201	2018 Results of Operations Summary
202	Summary of Other Revenue Sources
203	Summary of Depreciation Expense by Plant Type
204	Summary of Amortization Expense
205	Summary of Income Taxes
206	Summary of Taxes Other Than Income
207	Summary of Rate Base
208	Reasons for Changes in Rate Base since 2016 (UE 294)
209	Unbundled Results of Operations Summary

PGE Exhibit 201
2018 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	Base Business		5.60%
	2018 Results at 2016* Base Rates	Change for Reasonable Return	2018 Results After Change for Reasonable Return
	(1)	(2)	(3)
Operating Revenues			
Sales to Consumers (Rev. Req.)	1,783,435	99,897	1,883,332
Sales for Resale	-	-	-
Other Operating Revenues	25,841	-	25,841
Total Operating Revenues	1,809,276	99,897	1,909,173
Operation & Maintenance			
Net Variable Power Cost	353,586	-	353,586
Operations O&M	294,319	-	294,319
Support O&M	253,554	744	254,298
Total Operation & Maintenance	901,459	744	902,203
Depreciation & Amortization	377,278	-	377,278
Other Taxes / Franchise Fee	124,683	2,543	127,226
Income Taxes	121,190	38,559	159,749
Total Oper. Expenses & Taxes	1,524,610	41,846	1,566,457
Utility Operating Income	284,665	58,051	342,716
Rate of Return	6.198%		7.460%
Return on Equity	7.227%		9.750%
* 2016 Rates per approved UE 294			
Rate Base			
Plant in Service	9,879,272	-	9,879,272
Accumulated Depreciation	(4,735,925)	-	(4,735,925)
Accumulated Def. Income Taxes	(634,410)	-	(634,410)
Accumulated Def. Inv. Tax Credit	-	-	-
Net Utility Plant	4,508,938	-	4,508,938
Misc Deferred Debits	20,863	-	20,863
Operating Materials & Fuel	80,737	-	80,737
Misc. Deferred Credits	(73,318)	-	(73,318)
Working Cash	55,314	1,518	56,833
Total Rate Base	4,592,534	1,518	4,594,052

PGE Exhibit 201
2018 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	Base Business		5.60%
	2018 Results at 2016* Base Rates	Change for Reasonable Return	2018 Results After Change for Reasonable Return
	(1)	(2)	(3)
Income Tax Calculations			
Book Revenues	1,809,276	99,897	1,909,173
Book Expenses	1,403,420	3,287	1,406,707
Interest Rate Base @ Weighted Cost of Debt	118,717	39	118,756
Production Deduction	9,000	-	9,000
Permanent Sch M Differences	(24,268)	-	(24,268)
Temporary Sch M Differences	45,835	-	45,835
State Taxable Income	256,572	96,571	353,143
State Income Tax	20,136	7,322	27,459
Federal Taxable Income	236,436	89,249	325,684
Fed Income Tax	82,752	31,237	113,989
Deferred Taxes	18,301	-	18,301
Federal Tax Credits	-	-	-
Total Income Tax	121,190	38,559	159,749

PGE Exhibit 201
General Rate Case - 2018 Test Year
Capital Structure / Revenue Sensitive Costs
(000s)

Capital Structure:	**Amount**	**Share**	**Cost**	**Weighted**
Common Equity	N/A	50.00%	9.750%	4.875%
Preferred	N/A	0.00%	0.00%	0.000%
Long-Term Debt	N/A	50.00%	5.170%	2.585%
Total	N/A	100.00%		**7.460%**

Revenue Sensitive Costs:	
Revenues	100.0000%
OPUC Fees	0.3750%
Franchise Fees	2.5455%
O&M Uncollectibles	0.3700%
State Taxable Income	96.7095%
State Tax @ 7.212%	7.3328%
Federal Taxable Inc.	89.3768%
Federal Tax @ 35%	31.2819%
Total Income Taxes	**38.6146%**
Total Rev. Sensitive Costs	**41.9051%**
Utility Operating Income	58.0949%
Net To Gross Factor	**1.721321**
RSC Gross-Up Factor	1.0340

State Income Tax:

	Appor	Rate	Weighted
Montana	2.91%	6.75%	0.197%
Washington	0.00%	0.00%	0.000%
California	1.34%	8.84%	0.119%
Oregon	95.62%	7.60%	7.267%
State			7.582%
Composite Tax Rate:			**39.928%**

Check:	Fed Tax	35.00%
	State Tax	7.582%
	Tax Shield	-2.65%
	Composite	39.928%

Working Cash Factor	3.628%

PGE Exhibit 202
Other Revenue Detail
2014 - 2018 Test Year

Account	Description	2014 Actuals	2015 Actuals	2016 Actuals	2017 Budget	2018 Test Year
4470003	SalesfrResale-IntertiePGEtoPGE	(3,069,994)	(4,816,292)	(5,936,823)	(5,934,000)	(5,934,000)
4500001	Forefeited Discounts	(3,092,995)	(3,019,107)	(2,994,617)	(2,900,000)	(2,900,000)
4510001	Miscellaneous Service Revenues	(1,716,285)	(1,796,073)	(1,852,377)	(1,905,392)	(2,338,315)
4530001	Sales of Water & Water Power	27,627	22,164	24,166	-	-
4540001	Rent From Electric Property	(1,302,935)	(1,043,393)	(1,025,319)	(1,216,905)	(1,217,728)
4540002	RentFrElecProperty-Joint Pole	(6,180,231)	(6,564,797)	(7,679,162)	(6,234,855)	(6,279,394)
4560001	Other Electric Revenues	(4,538,748)	(3,487,297)	(3,648,451)	(2,971,527)	(2,973,166)
4560002	OthElecRev-RegulatoryDeferRev	-	-	-	-	-
4560003	OthElecRev-FishWildlifeRecrOps	(15,168)	(19,493)	(12,386)	-	(16,002)
4560004	OthElecRev-SSHG	(283,870)	(239,360)	(69,475)	(193,177)	(277,087)
4560005	OthElecRev-Utility Non-Kwh	(1,566)	(2,657)	(2,478)	-	-
4560012	OthElecRev-Steam Sales	(2,494,638)	(2,555,480)	(1,480,085)	(1,684,211)	(1,684,211)
4561001	TransRevOthers-Non-Intertie	(2,344,157)	(2,971,892)	(2,899,444)	(3,034,800)	(3,110,945)
4561002	TransRevOthers-Intertie	(5,683,073)	(5,285,337)	(5,080,702)	(5,044,000)	(5,044,000)
5660002	TransOp-MiscExp-IntertieWhePGE	3,069,994	4,816,292	5,936,823	5,934,000	5,934,000
Total		(27,626,038)	(26,962,722)	(26,720,329)	(25,184,867)	(25,840,848)

PGE Exhibit 203
Depreciation Detail ($000s)
2014 - 2017 Test Year

Property Group	(1) 2014 Actuals	(2) 2015 Actuals	(3) 2016 Actuals	(4) 2017 Forecast	(5) 2017 Forecast used for 2018 Test Year
Boardman	26,816	29,642	30,023	30,363	30,363
Colstrip	5,041	5,308	5,161	9,546	9,546
Beaver	3,668	4,644	5,573	7,483	7,483
Biglow Canyon	35,015	33,490	32,095	32,830	32,830
Carty			6,696	13,489	13,489
Coyote Springs	4,792	5,136	4,919	4,743	4,743
DSG	548	332	340	344	344
Port Westward	6,520	8,647	8,668	8,645	8,645
Port Westward 2	21	8,160	8,042	10,019	10,019
Solar		42	79	429	429
Tucannon	718	17,316	16,761	18,090	18,090
Hydro	11,847	15,806	18,319	20,995	20,995
Transmission	9,819	9,078	10,025	12,744	12,744
Distribution	118,604	97,611	101,051	107,446	107,446
General Plant	25,919	33,915	35,430	38,884	38,884
Total	**249,328**	**269,127**	**283,182**	**316,050**	**316,050**
Remove Boardman Decommissioning	(3,395)	(5,877)	(5,877)	(5,877)	(5,877)
Asset retirement depreciation - 4031001				7,325	7,325
Retail Adjustment				(74)	(74)
Adjusted Total	**245,933**	**263,250**	**277,305**	**317,424**	**317,424**

Notes:

(1) 2014 Boardman depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study.
2014 depreciation excludes coal car depreciation of $261 and vehicle depreciation of $4,214.

(2) 2015 Boardman depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study with additional 15% ownership of non-coal handling assets, bringing PGE total share to 80%.
2015 depreciation excludes coal car depreciation of $261 and vehicle depreciation of $3,516 or $3,637

(3) 2016 Boardman depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study with additional 10% ownership and retention program, bringing PGE total share to 90%.
2016 depreciation excludes coal car depreciation of $318 and vehicle depreciation of $4,781.
2016 Sunway becomes part of base business

(4) 2017 Boardman forecasted depreciation includes effects of the Schedule 145 Tariff update, which incorporates the site specific decomissioning study.
2017 forecasted depreciation excludes coal car depreciation of $266 and vehicle depreciation of $4,304.

PGE Exhibit 204
Amortization Detail
2014 - 2018 Test Year
($000)

	FERC		(1)	(2)	(3)	(4)	(5)
Item	**Account**	**AWO**	**2014 Actuals**	**2015 Actuals**	**2016 Actuals**	**2017 Forecast**	**2017 Forecast used for 2018 Test Year**
Software Amortization (Intangible)	404.0		22,237	30,053	35,668	46,999	46,999
Other Intangible Plant (Includes Hydro Relicensing)	404.0		3,163	8,312	8,430	9,294	9,294
Trojan Decommissioning	407.0	7000000045	3,500	3,500	3,500	3,500	3,500
Trojan Spent fuel Settlement	407.0	3000000786	0	(16,800)	(16,340)	(17,312)	0
Independant Evaluator Deferral	407.3		20	547	35	0	0
Colstrip Common FERC Adjustment	407.3	7000000107	322	322	322	107	107
Schedule 110 EE Asset Balancing Acccount	407.3	7000000124	921	902	884	942	942
AMI Project Office Costs	407.3		0	0	0	0	0
Fit Pilot Program	407.3	7000002001	5,051	6,248	7,975	7,740	7,740
Regulatory Deferral Amortz	407.3	7000010741	15,978	18,959	155	0	0
Residual Balance	407.3		0	0	0	0	0
Regulatory Deferral (capital Deferral)	407.4	7000010741	13	0	0	0	0
2011 Local 408/MCBIT Deferral	407.4	3000000135	(180)	168	515	(440)	(200)
Int Income PES Note	407.4	7000000319	0	0	0	0	0
ISFSI Tax Credits-Used	407.4	7000000324	0	(5,290)	(300)	0	0
SunWay 3	407.4	7000000727	(45)	(45)	(45)	0	0
			50,979	46,875	40,798	50,831	68,383
Allocated to retail							(47)
Total Amortization			**50,979**	**46,875**	**40,798**	**50,831**	**68,336**

PGE Exhibit 205
Income Tax Summary
(000s)

Income Tax Expense	UE 294 2016 Test Year	2018 Test Year
Book Revenues	1,891,229	1,909,173
Book Expenses (including Depreciation)	1,483,716	1,406,707
Interest Deduction	120,306	118,756
Book Taxable Income	287,206	383,709
Production Deduction	-	9,000
Permanent Sch. M	(24,911)	(24,268)
Temporary Sch. M	97,277	45,835
Tax Taxable Income	214,841	353,143
Current State Taxes	15,495	27,459
State Tax Credits	(992)	-
Net State Income Tax	14,503	27,459
Federal Taxable Income	200,338	325,684
Current Federal Taxes	70,118	113,989
Federal Tax Credits	(49,150)	-
ITC Amortization	-	-
Deferred Taxes	38,607	18,301
Total Income Tax	74,078	159,749
Effective Tax Rate	25.79%	41.63%
Change in Taxes		85,671

Analysis of Tax Change:

Effective Tax Rate Change	15.84%
Book Taxable Income (UE 294)	287,206
Increase in Taxes Due to Higher Effective Rate	45,494
Change in Book Taxable Income (2017 vs UE 294)	96,503
2017 Effective Tax Rate	41.63%
Increase in Taxes Due to Higher Book Taxable Income	40,177
Sum of Tax Impacts	85,671

PGE Exhibit 206
Taxes Other Than Income
2014 - 2018 Test Year

Item	FERC Account	AWO	2014 Actual	2015 Actual	2016 Actual	2017 Budget	2018 Forecast
Payroll Taxes	408.1	Note 1	13,592,277	13,719,102	13,522,625	16,333,882	16,109,015
Property Taxes - Oregon	408.1	4081001	45,345,336	47,797,482	51,759,568	55,796,028	52,680,261
Property Taxes - Washington	408.1	4081002	51,839	2,201,144	1,640,162	2,059,752	2,059,752
Property Taxes - Montana	408.1	4081003	4,507,881	5,401,265	5,752,457	6,058,752	6,003,312
Franchise Fees	408.1	4081010, 4081011	41,634,096	43,406,579	43,125,386	43,546,507	47,939,369
Foreign Insurance Excise Tax	408.1	4081012	19,184	9,984	9,485	-	-
Misc. Tax & Lic Fees - Oregon	408.1	4081013	1,368,136	1,667,103	1,995,850	1,971,706	1,971,706
Misc. Tax & Lic Fees - Montana	408.1	4081014	327,767	441,288	407,253	432,504	462,504
Total Taxes Other Than Income			106,846,515	114,643,947	118,212,785	126,199,131	127,225,919

Note 1: Payroll Tax accounts include 4081004, 4081005, 4081006, 4081007, 4081008 and 4081009

PGE Exhibit 207
Rate Base (000s)
Based on Ending 12/31/17 Balance

		12/31/2017 Balance
	Plant in Service	9,879,272
Less:	Accumulated Depreciation/Amortization	(4,735,925)
	Accumulated Deferred Taxes	(634,410)
	Accumulated Deferred ITC	-
Net Utility Plant		4,508,938
Operating Materials and Fuel Stocks		80,737
Deferred Debits		
	Colstrip Common FERC Adj	-
	Glass Insulators	4,770
	Dispatchable Standby Generation	10,856
	UE 197 Generation Maintenance Deferral	684
	CET	3,923
	IT	1,737
Deferred Credits		
	Injuries & Damages	(9,137)
	Customer Deposits	(12,281)
	Incentive Adjustment (UE 283)	(8,500)
	Major Maint. Accruals (Coyote & PW1&2)	(1,107)
	Post Retirement Liabilities	(43,329)
	Misc. Other	(70)
Working Capital		56,833
Rate Base		4,594,052

PGE Exhibit 208
Rate Base Comparison
UE 294 vs. 2018 Test Year
(000s)

	UE 294 Test Year	Working Cash Requirements	Thermal Plant Maint. Accruals	Plant Additions/ Depr/Amort	Accum. Def. Taxes (bonus depr., etc.)	Misc. Other	YE 2017 Rate base
Plant in Service	9,164,479			714,793			9,879,272
Accumulated Depr/Amort	(4,225,065)			(510,860)			(4,735,925)
Accumulated Deferred Taxes/ITC	(590,561)				(43,849)		(634,410)
Net Utility Plant	4,348,853	-	-	203,933	(43,849)	-	4,508,938
Other Rate Base	34,801		550			(7,069)	28,282
Working Cash	56,518	314	-	-		-	56,833
Rate Base	4,440,173	314	550	203,933	(43,849)	(7,069)	4,594,052

PGE Exhibit 209
Unbundled Results of Operations Summary
2016 Results at Reasonable Return
Dollars in $000s

	Production	Transmission	Distribution	Ancillary	Metering	Billing	Consumer	Total
Operating Revenues								
Sales to Consumers (Rev. Req.)	1,090,691	28,486	635,813	4,859	8,430	63,013	52,039	1,883,332
Sales for Resale	-	-	-	-	-	-	-	-
Other Operating Revenues	2,214	14,079	14,463	(4,859)	(3)	(11)	(43)	25,841
Total Operating Revenues	1,092,906	42,566	650,277	-	8,427	63,002	51,996	1,909,173
Operation & Maintenance								
Net Variable Power Cost	353,586	-	-	-	-	-	-	353,586
Total Fixed O&M	162,949	10,089	121,198	-	-	-	-	294,235
Other O&M	57,596	3,943	94,139	-	1,731	53,148	43,824	254,382
Total Operation & Maintenance	574,131	14,032	215,337	-	1,731	53,148	43,824	902,203
Depreciation & Amortization	190,489	10,025	158,735	-	3,808	9,236	4,985	377,278
Other Taxes / Franchise Fee	54,002	2,645	69,762	-	350	198	269	127,226
Income Taxes	85,256	5,011	67,460	-	788	198	1,036	159,749
Total Oper. Expenses & Taxes	903,878	31,713	511,294	-	6,678	62,780	50,114	1,566,457
Utility Operating Income	189,028	10,853	138,983	-	1,748	222	1,883	342,716
Rate of Return	7.46%	7.46%	7.46%	N/A	7.46%	7.46%	7.46%	7.46%
Return on Equity	9.75%	9.75%	9.75%	N/A	9.75%	9.75%	9.75%	9.75%
Average Rate Base								
Utility Plant in Service	5,199,280	339,986	4,154,559	-	43,464	86,928	55,055	9,879,272
Accumulated Depreciation	2,300,913	161,963	2,154,246	-	16,243	76,573	25,988	4,735,925
Accumulated Def. Income Taxes	454,001	37,479	127,862	-	4,112	9,679	1,277	634,410
Accumulated Def. Inv. Tax Credit	-	-	-	-	-	-	-	-
Net Utility Plant	2,444,366	140,544	1,872,451	-	23,109	677	27,790	4,508,938
Operating Materials & Fuel	61,604	576	18,556	-	-	-	-	80,737
Misc Deferred Debits	10,871	4,814	1,316	-	609	1,575	1,678	20,863
Misc. Deferred Credits	(15,748)	(1,610)	(47,831)	-	(522)	(1,556)	(6,051)	(73,318)
Working Cash	32,794	1,151	18,550	-	242	2,278	1,818	56,833
Total Average Rate Base	2,533,887	145,476	1,863,043	-	23,438	2,974	25,235	4,594,052