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June 6, 2018

Via Electronic Filing and Federal Express

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
2018 Request for a General Rate Revision
Docket No. UE 335

Dear Filing Center:

Please find enclosed the Opening Rate Case Testimony and Exhibits of Bradley G. Mullins (AWEC/200-206) and Dr. Marc M. Hellman (AWEC/300-309) on behalf of the Alliance of Western Energy Consumers ("AWEC") in the above-referenced docket.

Pursuant to OAR 860-001-0170(2), and per the Commission's request, AWEC is also submitting an original and four (4) hard copies of its testimony and exhibits via Federal Express. The confidential portions of Mr. Mullins' and Dr. Hellman's testimony and exhibits are being handled in accordance with Order No. 18-047.

Thank you for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Haley M. Thomas
Haley M. Thomas

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **confidential portions of the Opening Rate Case Testimony and Exhibits of Bradley G. Mullins and Dr. Marc M. Hellman** upon the parties shown below by mailing copies via First Class U.S. Mail, postage prepaid, and by sharing copies via the Huddle workspace in this docket.

Dated at Portland, Oregon, this 6th day of June, 2018

Sincerely,

/s/ Haley M. Thomas
Haley M. Thomas

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**BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON
UE 335**

In the Matter of)

PORTLAND GENERAL ELECTRIC)
COMPANY,)

Request for a General Rate Revision.)
_____)

**OPENING TESTIMONY OF BRADLEY G. MULLINS
ON BEHALF OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS
(REDACTED VERSION)**

June 6, 2018

TABLE OF CONTENTS

I.	Introduction	1
II.	Tax Cuts and Jobs Act.....	3
	a. Impact on Federal Income Tax Expense	4
	b. Composite Income Tax Rate Corrections	6
	c. Excess Tax Reserves	7
	d. The Interim Period Deferral	12
III.	Capital Expenditure Forecast	14
	a. Rate Base Measurement Date.....	16
	b. Field Voice Communications / Spectrum Projects.....	18
	c. Project Specific Adjustments	20
	d. Non-discrete Capital Additions	25
IV.	Accumulated Deferred Income Taxes	26
	a. Production Tax Credit Carryforwards	28
	b. Accrued Vacation	31
	c. Management Stock Incentive Plan	32
	d. Boardman Severance	32
	e. Provision for Injury and Damages.....	33
V.	Miscellaneous Revenue Requirement Issues	34
	a. Depreciation Reserves	34
	b. Trojan Decommissioning Trust.....	34
	c. Customer Touchpoints R&D Tax Credit.....	36
	d. UE 283 Incentives Adjustment.....	38
	e. Dispatchable Generation Regulatory Asset.....	38
	f. Boardman Severance Payments	40
VI.	Permanent Direct Access Program.....	41
	a. Permanent Direct Access Program and PGE's Proposed Changes	42
	b. Transition Period	44
	c. Program Cap	45
	d. Cost of Freed-up Capacity.....	46
VII.	Other Rate Case Issues	49
	a. Major Storm Balancing Account.....	49
	b. Customer Touchpoints Deferral	51
	c. Renewable Adjustment Clause.....	52

EXHIBIT LIST

AWEC/201 – Revenue Requirement Calculations

AWEC/202 – Impact of Tax Cuts and Jobs Act on Filing

AWEC/203 – Interim Period Deferral

AWEC/204 – Notice of Internal Use Software Regulations

AWEC/205 – Responses to Data Requests

Confidential AWEC/206 – Confidential Attachments to Data Responses

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 1750 SW Harbor Way, Ste 450, Portland, Oregon 97201.

Q. ARE YOU THE SAME WITNESS WHO FILED OPENING POWER COST TESTIMONY IN THIS DOCKET ON MAY 24, 2018?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR OPENING TESTIMONY.

A. I testify regarding my initial review of PGE's revenue requirement. In my review, I recommend a revenue requirement reduction of \$28,440,143, relative to the rates that recently went into effect on January 1, 2018 in Docket No. UE 319 (the "2017 GRC"). My analysis is in contrast to the revenue increase of \$85,908,262, or 4.8%, PGE reported in its initial filing. If one considers the tax savings from the reduction of the federal corporate income tax rate, however, it is apparent that the actual magnitude of the cost increases PGE proposes to pass onto ratepayers is much greater than 4.8%. Absent the beneficial impacts associated with that legislation, the magnitude of the increase is really 9.7% in a year with no new power plant additions. In addition to revenue requirement issues, I also testify regarding PGE's permanent direct access program, as well as a few other miscellaneous rate case issues.

Q. WHAT WAS THE SCOPE OF YOUR REVIEW OF PGE'S REVENUE REQUIREMENT?

A. I initially focused on tax expense, PGE's capital forecast, and other miscellaneous revenue requirement issues. Dr. Marc Hellman will also be providing testimony on behalf the Alliance of Western Energy Consumers ("AWEC") discussing primarily labor-related issues. My revenue requirement analysis incorporates the impact of Dr. Hellman's recommendations.

1 **Q. HAVE YOU PREPARED A SUMMARY OF AWEC'S ADJUSTMENTS?**

2 A. Yes. Table 1 below summarizes AWEC's initial revenue requirement adjustments. This does
3 not account for the adjustments I propose to PGE's 2019 power cost forecast in AWEC/100.

TABLE 1
Contested Revenue Requirement Adjustments
Deficiency / (Sufficiency) (\$000)

PGE Initial Filing, Deficiency		85,812
AWEC Adjustments:		
A1	Cost of Capital	(797)
<u><i>Tax Cuts And Jobs Act</i></u>		
A2	Composite Tax Rate Correction	(1,247)
A3	EDFIT Correction	(1,564)
A4	EDFIT Alternative Method	111
A5	Interim Period Deferral Amortization	(47,912)
<u><i>Capital Expenditures</i></u>		
A6	Rate Base Measurement Date	(11,584)
A7	Field Voice Communications / Spectrum	(3,715)
A8	Project Specific Adjustments	(179)
A9	Non-Discrete Capital Additions	(2,721)
<u><i>Accumulated Deferred Taxes</i></u>		
A10	PTC Carry Forwards	(7,182)
A11	Accrued Vacation	(500)
A12	Stock Incentive Plan	(362)
A13	Boardman Severance	(287)
A14	Injuries and Damages	(252)
<u><i>Other Revenue Requirement Issues</i></u>		
A15	Depreciation Reserve	(2,046)
A16	Trojan NDT Amortization	(725)
A17	Touchpoints R&D Tax Credit	(3,322)
A18	UE 283 Incentives Adjustment	(518)
A19	Dispatchable Generation Regulatory Asset	(1,221)
A20	Boardman Severance	(547)
A21	Level III Storm Escalation	(93)
<u><i>Impact of adjustments Sponsored by Dr. Hellman</i></u>		
A22	Employee Costs	(27,587)
Total Adjustments		(114,252)
Adjusted Revenue Requirement (Sufficiency)		(28,440)

Calculations underlying the revenue requirement adjustments in Table 1, including the rate base and operating income impacts, can be found in Exhibit AWEC/201. Brief summaries of the adjustments are as follows:

1. **Tax Cuts and Jobs Act.** I have identified several corrections associated with PGE's implementation of the Tax Cuts and Jobs Act in revenue requirement, including amortization of excess tax expenses reflected in revenue requirement deferred over the Interim Period of January 1, 2018 through December 31, 2018.
2. **Capital Expenditures.** I propose several changes to PGE's capital budget, including the adoption of an October 31, 2018 rate base measurement date and a project-level review of major projects.
3. **Accumulated Deferred Income Taxes.** I propose to remove several book-tax difference items from accumulated deferred income taxes reflected in rate base, including production tax credits.
4. **Other Revenue Requirement Issues.** I make a number of other corrections and adjustments to the revenue requirement calculation, including a provision for an R&D tax credit associated with the Customer Touchpoints system.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO PGE'S PERMANENT DIRECT ACCESS PROGRAM?

A. For PGE's permanent direct access program, I oppose PGE's proposal to extend the period for transition charges from five years to ten. I also recommend eliminating the current enrollment cap. Finally, I recommend establishing a credit for the freed-up value of capacity in the transition adjustment calculation in periods when PGE is capacity-short.

II. TAX CUTS AND JOBS ACT

Q. PLEASE PROVIDE SOME BACKGROUND ON THE TAX CUTS AND JOBS ACT.

A. The Tax Cuts and Jobs Act ("TCJA"), HR 1 of the 115th Congress, was signed into law on December 22, 2017. Among other things, the TCJA resulted in a reduction to the Federal corporate income tax rate from 35% to 21%.

1 **Q. HOW DOES THE TCJA AFFECT THE CALCULATION OF REVENUE**
2 **REQUIREMENT?**

3 A. The TCJA impacts revenue requirement in at least four ways. First, federal income tax
4 expense included in the results of operations table must be stated at the lower, 21% rate.
5 Second, balances associated with ADIT must be revalued at the new rate, including
6 consideration of previously over-deferred amounts, often referred to as Excess Deferred
7 Federal Income Taxes (“EDFIT”). Third, the tax expenses over-collected in rates over the
8 period January 1, 2018 through December 31, 2018 (the “Interim Period”) must be deferred
9 and amortized to results. Fourth, the conversion factor used in the calculation of the revenue
10 deficiency or surplus must be updated to reflect the TCJA.

11 **Q. HAS PGE CONSIDERED THESE IMPACTS?**

12 A. PGE’s filing did not consider the revenue requirement impacts of the Interim Period tax.
13 While PGE did consider the other elements necessary to implement the TCJA, I have identified
14 a number of corrections and issues associated with those elements. I discuss those in the
15 following sub-sections.

16 **a. Impact on Federal Income Tax Expense**

17 **Q. HOW DOES THE LOWER TAX RATE IMPACT TAX EXPENSES INCLUDED IN**
18 **REVENUE REQUIREMENT?**

19 A. Using the forecasting assumptions in PGE’s initial filing, the impact on federal income tax
20 expense of the new 21% tax rate is \$75,569,264. This part of the TCJA represents one of the
21 more straightforward impacts of the legislation on ratepayers. It may be calculated by
22 comparing the income tax expense reflected in forecasted results, to the income tax expense
23 calculated using the 35% tax rate that had been in effect prior to January 1, 2018. Importantly,
24 income tax expense included in a utility’s results of operations does not reflect the actual taxes

1 the utility pays (i.e., current taxes). Instead, income tax expense includes a provision for
2 current taxes, as well as deferred taxes. Thus, the impact of the lower tax rate may generally
3 be calculated by comparing the current and deferred tax amounts calculated using the
4 respective tax rates before and after the effective date, although one must also use the
5 composite tax rate of the utility, taking into consideration the impacts of state and local income
6 taxes.

7 **Q. WHAT COMPOSITE TAX RATE WAS INCLUDED IN PGE'S FILING?**

8 A. Considering state and local income taxes, PGE calculated a 27.5% composite income tax rate.
9 PGE's state income taxes are apportioned between the three states of Oregon, Montana, and
10 California. PGE also includes an amount apportioned to the City of Portland income taxes,
11 which are also included in income tax expense. Multnomah County income taxes are not
12 included in income tax expense because those are recovered through Schedule 106. In
13 contrast, had a 35.0% tax rate been used, the composite income tax rate, using PGE's
14 calculation, would have been 40.1%.

15 **Q. WHAT WAS THE REVENUE REQUIREMENT EFFECT OF THE TCJA TAX RATE?**

16 A. I've performed this calculation in Exhibit AWEC/202. After considering the excess deferred
17 federal income taxes of \$7,010,362, which will be discussed further below, PGE's filing really
18 represents a rate increase to customers of \$173,613,520, if the TCJA had not been
19 implemented. Thus, from the perspective of evaluating the reasonableness of the Company's
20 request for higher rates – the fifth in six years – the rate increase here is more appropriately
21 viewed as a 9.7% rate increase. Given the passage of the TCJA, customers should be seeing
22 rate reductions, not rate increases.

b. Composite Income Tax Rate Corrections

Q. DID YOU IDENTIFY ANY ISSUES WITH PGE'S COMPOSITE TAX RATE WHEN REVIEWING ITS INCOME TAX EXPENSE CALCULATIONS?

A. Yes. In the course of my review, I identified a number of corrections to PGE's composite income tax rate calculations. I have calculated a lower composite income tax rate of 26.86%, in contrast to the 27.15% composite income tax rate PGE assumed in its filing. My calculation of the composite tax rate may be found on Page 2 of Exhibit AWEC/201.

Q. WHERE CAN PGE'S CALCULATION OF ITS COMPOSITE INCOME TAX RATE BE FOUND?

A. PGE's calculation of its composite income tax rate may be found in the workpaper titled "Blended Statutory Tax Rate 2019 GRC." That workpaper details the historical apportionment of taxable income between Oregon, Montana, and California, as well as to the City of Portland. It also considers the offsetting impacts of deducting state and local taxes when calculating federal income tax expense, as well as the impacts of deducting local taxes when calculating state tax expense.

Q. WHAT CORRECTIONS HAVE YOU IDENTIFIED?

A. The first issue I have identified is that PGE did not use the actual historical apportionment between the three states—Oregon, Montana, and California—where PGE has property, employees, or sales. Different states use different formulas for determining apportionment, so it is necessary to consider the historical apportionment when determining the composite rate. From what I can tell in the workpaper, PGE increased the historical apportionment factors, without any explanation, in order to force the calculation to tie to 27.15%.

Second, PGE did not consider the benefit of deducting Multnomah County income taxes on its state and federal tax returns. Schedule 106 only considers the taxes paid to

1 Multnomah County, and does not consider the tax savings associated with deducting those
2 taxes when calculating state and federal income taxes.

3 Finally, PGE did not consider that the initial \$1,000,000 of Oregon taxable income is
4 taxed at a lower 6.5% tax rate, which shields approximately \$10,000 in state tax expense.

5 **Q. WHAT IS THE IMPACT OF THESE CORRECTIONS?**

6 A. Applying the lower composite tax rate of 26.84%, as well as the graduated corporate income
7 tax rate, produces a reduction of \$783,640 of post-tax revenues, which corresponds to a
8 \$1,247,145 reduction to pre-tax revenue requirement.

9 **c. Excess Tax Reserves**

10 **Q. WHAT ARE EXCESS DEFERRED FEDERAL INCOME TAXES?**

11 A. The TCJA codifies several normalization provisions surrounding the treatment of EDFIT,
12 which simplifies the treatment of the balance sheet impacts of the tax law change for public
13 utilities. Similar provisions were put into place when the Tax Reform Act of 1986 was
14 enacted.^{1/}

15 Effectively, EDFIT represent a financial gain to the utility, and absent the TCJA
16 normalization provisions surrounding EDFIT, a utility might have claimed that it was entitled
17 to retain those benefits. Or, perhaps ratepayers might have claimed that they should receive
18 those gains through a single lump-sum payment. The TCJA, however, simplifies the
19 ratemaking treatment surrounding the tax changes by prescribing the specific methods that
20 must be used by regulators to account for the EDFIT benefits associated with plant balances,
21 avoiding some controversy over the way that those amounts get returned to ratepayers.

^{1/} See, e.g., PLR 200743030.

1 Under Generally Accepted Accounting Principles (“GAAP”), the general rule is that
2 when a change in the tax rate is enacted into law, the effects of the change must be reported in
3 the period that includes the “enactment date.”^{2/} The normalization requirements for EDFIT in
4 IRC § 168(i)(9), however, provide an exception to that general rule for public utilities.

5 For business enterprises other than a public utility, the change in tax rate results in
6 material balance sheet impacts. For a non-utility business enterprise, deferred tax liabilities
7 and assets must be revalued at the new tax rate. Most utilities have net deferred tax liability
8 balances, which represent funds in the utility’s possession being held in reserve to pay for taxes
9 the utility must pay in the future. Thus, if the tax rate declines, the tax liability balance
10 declines, resulting in the recognition of a gain, similar to the gain that occurs when the
11 principal balance of a loan is forgiven. For non-utilities, this gain flows through the income
12 statement in the current period, in one lump-sum.

13 For public utilities, however, the treatment is different. When implementing the
14 normalization requirements of IRC § 168(i)(9)—a rare instance where the Internal Revenue
15 Service may exercise authority over the specific ratemaking methodology that state regulatory
16 commissions use to establish public service rates—the balance sheet gains associated with the
17 change in tax rate must remain on the public utility’s balance sheet and be considered in rate
18 base as an excess tax reserve, i.e., EDFIT. Further, rather than recording those benefits in one
19 lump-sum, as required under GAAP, this ratemaking requires the utility to recognize the
20 financial gains associated with the lower tax rate over an extended period of time.

^{2/} See Financial Accounting Standards Board (“FASB”), Statement of Financial Accounting Standards No. (“SFAS”) 109, Accounting for Income Taxes ¶ 27; See also FASB Accounting Standards Codification (“ASC”) 740-25-47.

1 The amortization schedule is generally intended to correspond to the period over which
2 the book-tax differences underlying EDFIT are expected to reverse, and two general methods
3 are available to amortize the excess reserves to results—the Average Rate Assumption
4 Methodology (“ARAM”) and an Alternative Method.^{3/} The ARAM methodology is
5 computationally detailed and requires the utility to amortize the EDFIT reserve by plant
6 vintage, ratably in proportion to the reversal of the book-tax differences underlying the EDFIT
7 reserve. Provided the utility possesses the vintage data necessary to perform the ARAM
8 method, the utility must use the ARAM when establishing rates. If the vintage data is not
9 available, the utility must use the Alternative Method. Under the Alternative Method, EDFIT
10 is reversed based on the weighted average life or composite rate used to compute depreciation
11 for, or ratably over the remaining regulatory life of the property.

12 **Q. DO THE IRS NORMALIZATION REQUIREMENTS APPLY TO ALL DEFERRED**
13 **TAX BALANCES?**

14 A. No. The IRS normalization requirements apply only to deferred tax balances associated with
15 the use of accelerated depreciation—both the Modified Accelerated Cost Recovery System
16 (“MACRS”) and bonus depreciation—in IRC § 168k. Accordingly, normalization accounting
17 methods outlined in the TCJA only apply to deferred tax balances associated with utility plant.
18 Those deferred tax balances are often referred to as being *protected*.

19 With respect to the other deferred tax balances, those are often referred to as
20 *unprotected*, since state Commissions, through the use of regulatory accounting, have greater
21 leeway in determining how the gains on those EDFIT balances get returned to ratepayers.

^{3/} The IRS has historically referred to the “Reverse South Georgia Method,” although I used a generic term, Alternative Method, rather than referring to a specific geographic area of the United States.

1 **Q. DID PGE CONSIDER EDFIT IN ITS FILING?**

2 A. Yes. In its operating results PGE did include \$7,010,362 in reversal in income tax expense.
3 PGE's filing, however, does not identify the balances associated with the excess tax reserve
4 accounts, or the amortization schedule.

5 **Q. DID PGE PROVIDE THE DATA NECESSARY TO SUPPORT ITS CALCULATION?**

6 A. No. While I conducted several rounds of discovery to determine the appropriate EDFIT, PGE
7 has not yet provided sufficient information to review its calculation of EDFIT. PGE alleges
8 that it has used the ARAM methodology. Notwithstanding, PGE could not provide any
9 support for its calculation of the ARAM other than the values that were hard-coded into its
10 PowerTax and Tax Provision modules. In response to AWEC Data Request 017, for example,
11 PGE stated that it could not provide the calculations based on property vintage because those
12 amounts were "imbedded in thousands of system calculations."^{4/} I have reviewed this level of
13 data for other utilities, and because having that data is a prerequisite of using the ARAM, it is
14 impossible to consider the reasonableness of PGE's calculation without it.

15 **Q. PLEASE SUMMARIZE THE DISCOVERY YOU CONDUCTED.**

16 A. In AWEC Data Request 17, PGE was requested to provide calculations underlying its EDFIT
17 calculations as of December 31, 2017. In that response, PGE claims to have used the ARAM
18 and provided two attachments, which were two hard-coded outputs tables from the power tax
19 model used to calculate PGE's tax provision. Attachment A contained all EDFIT balances,
20 and Attachment B contained the reversal amount, but not the vintage level data necessary to
21 support the ARAM calculation. Further, in Attachment B, PGE reported \$8,115,311 of EDFIT
22 reversal, in contrast to the \$7,010,362 included in its filing.

^{4/} Exhibit AWEC/205 at 8.

1 **Q. DID PGE CLARIFY WHY THE EDFIT REPORTED IN AWEC DATA REQUEST 17**
2 **WAS DIFFERENT THAN THE AMOUNT INCLUDED IN ITS FILING?**

3 A. Yes. In AWEC Data Request 45, PGE clarified that the \$8,115,311 of EDFIT reversal
4 reported in Data Request 17 was a more recent estimate. This update has been incorporated
5 into Table 1 and Exhibit AWEC/201. The revenue requirement impact is a reduction to
6 revenue requirement of \$ [REDACTED].

7 **Q. DOES PGE HAVE THE NECESSARY VINTAGE ACCOUNT DATA TO PERFORM**
8 **THE ARAM?**

9 A. No. Based on the way PGE performs its depreciation study—using the equal life group
10 approach—the accumulated book depreciation is not tracked by vintage. Rather, the
11 accumulated depreciation amount by vintage is implied by the shape of the survivor curve, and
12 allocated to the respective vintages. PGE confirmed in response to AWEC Data Request 46,
13 subpart d that “Book depreciation is *allocated* to the vintage Tax Class records using a similar
14 method to the plant depreciation module depreciation calculation.”^{5/}

15 **Q. HAVE YOU QUANTIFIED THE IMPACT OF USING THE COMPOSITE**
16 **DEPRECIATION RATES?**

17 A. Yes. I had intended to perform this calculation by FERC account. When asked for the FERC-
18 level data in AWEC Data Request 46, however, PGE was unable to produce the underlying
19 data.^{6/} Notwithstanding, PGE’s composite depreciation rate is 3.53%, per UM 1809/
20 Stipulating Parties/102 Page 5.

21 For the protected EDFIT balance, I used the year-ending EDFIT balance related to
22 property accounts reported in PGE’s response to AWEC Data Request 10 of \$754,070,950.^{7/}

^{5/} Exhibit AWEC/205 at 14 (PGE Resp. to AWEC DR 046) (emphasis added).

^{6/} Id.

^{7/} Id. at 4-7 (PGE Resp. to ICNU DR 010 Attach. A)

1 From that value, the EDFIT balance of \$245,611,407 was calculated and, after applying the
2 composite rate, an EDFIT amortization amount of \$8,670,083. This calculation may be seen
3 on Page 3 of AWEC/201.

4 To calculate the revenue requirement impact, I also assumed one year's worth of
5 accumulated EDFIT amortization, resulting in an offsetting increase to rate base. PGE did not
6 consider the declining EDFIT balance in its filing. After these adjustments I calculate an
7 increase of \$110,638 with respect to the EDFIT calculation.

8 **d. The Interim Period Deferral**

9 **Q. DID PGE CONSIDER THE INTERIM PERIOD TAX SAVINGS OVER THE PERIOD**
10 **JANUARY 1, 2018 THROUGH DECEMBER 31, 2018 IN ITS RATE FILING?**

11 A No. PGE will recognize significant savings over the Interim Period, in connection with the
12 TCJA. The Company filed a deferral application on December 29, 2017 to ensure this savings
13 is captured for the benefit of customers.^{8/} However, no determination has been made yet
14 regarding when this savings will be returned. Because this savings can now be calculated with
15 reasonable accuracy, I recommend that it begin to be passed back to customers at the start of
16 the rate-effective period for this case.

17 **Q. HOW HAVE YOU CALCULATED THE DEFERRAL FOR INTERIM PERIOD TAX**
18 **SAVINGS?**

19 A. In response to AWEC Data Request 126, PGE provided the final revenue requirement model
20 used to establish rates in Docket UE 319. Using that model, I calculated the tax expense
21 savings associated with the lower tax rate by changing the marginal tax rate in the model. My
22 calculation may be found in Exhibit AWEC/203. In addition, it is also necessary to consider

^{8/} Docket No. UM 1920.

the EDFIT amortization that will accumulate in the Interim Period in an amount equal to that described above. The results of those calculations are as follows:

TABLE 2
Interim Period Tax Savings \$

Tax Expense Savings (Pre-Tax)		70,791,000
EDFIT Amortization (Post-Tax)	8,670,083	
Conversion Factor	70.63%	
EDFIT Amortization (Pre-Tax)		12,275,256
Total Interim Period Savings		83,066,256

Q. HOW SHOULD THESE VALUES BE RETURNED TO RATEPAYERS?

A. I recommend that the utility's typical general rate case cycle be a primary consideration when establishing the amortization period, with a target of returning the interim period savings over two rate case cycles. This treatment will promote rate stability and make it easier for PGE to forego its next rate case. Since PGE has been filing annual rate cases, I recommend using a two-year amortization period.

Q. DO YOU RECOMMEND THAT THE INTERIM PERIOD DEFERRAL BE INCLUDED IN RATE BASE?

A. No. I recommend that the amortization be tracked outside of rate base and included in an account that accrues interest at PGE's pre-tax cost of capital. Further, I recommend adopting a levelized amortization schedule that brings the balance to zero over the two-year period. This amortization treatment is similar to the treatment of Trojan decommissioning costs and the calculation may be found in Exhibit AWEC/201, Page 4. As detailed there, I calculate monthly, pre-tax amortization of \$3,854,600, and annual amortization of \$46,255,200.

1 **Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF YOUR**
2 **RECOMMENDATION?**

3 A. The revenue requirement impact of the Interim Period deferral is a reduction of \$47,911,701,
4 the pre-tax amortization amount adjusted for revenue sensitive costs.

5 **III. CAPITAL EXPENDITURE FORECAST**

6 **Q. PLEASE SUMMARIZE YOUR REVIEW OF PGE'S BUDGET.**

7 A. Another major driver of PGE's rate request is related to its budgeted capital expenditures. The
8 problem with using these budgets, however, is that they are difficult, if not impossible, to
9 independently verify. My review of PGE's budget consisted of four parts. First, I considered
10 the date that PGE proposes to measure rate base. Second, I discuss an issue associated with the
11 Field Voice Communications project, which was included in PGE's capital attestation in UE
12 319. Third, I performed a project-by project review of discrete projects with a capital budget
13 exceeding \$10,000,000. Fourth, I reviewed non-discrete capital projects, as well as smaller
14 capital projects in comparison to historical capital spending levels.

15 **Q. HAS THE COMMISSION HISTORICALLY ALLOWED UTILITIES TO USE**
16 **BUDGETED EXPENDITURES FOR RATEMAKING PURPOSES?**

17 A. In Oregon, there are no specific statutes or regulations specifying the appropriate test year to be
18 used in a utility rate filing. In fact, the Company appears to have used some form of a future
19 test year, relying in part on budgeted expenditures, for ratemaking purposes since at least
20 1974.^{9/} Nevertheless, I am not aware that the Commission has ever expressly required the
21 Company to use a future test year, or even endorsed the Company's decision to do so in every
22 general rate case. Indeed, the Commission has previously recognized that it has allowed

^{9/} See American Can Co. v. Lobdell, 55 Or.App 451, 462, 638 P.2d 1152, 1159 (1982)

1 utilities to use future test years, historical test years, or a combination of the two,^{10/} and when it
2 did affirmatively endorse the Company's use of a future test year, it did so recognizing that the
3 Company "will undergo major expense changes which will not be felt until the second half of
4 [the test year], and setting rates for the future cannot be accomplished in any equitable manner
5 without considering the expenses."^{11/}

6 **Q. WHAT IS YOUR VIEW ON USING BUDGETED EXPENDITURES?**

7 A. My view is that using a historical test period is fairer to ratepayers. Notwithstanding, where
8 the use of budgets is allowed, the Commission may appropriately exercise significant
9 discretion when establishing those budgets.

10 **Q. WHAT AMOUNT OF FORECAST EXPENDITURES HAS PGE PROPOSED?**

11 A. The capital project data was provided in response AWEC Data Request 26, Confidential
12 Attachment A, where PGE forecast capital expenditures of \$673,320,026 in calendar year
13 2018.^{12/} PGE feeds its capital forecast into its system planner model, which calculates monthly
14 plant balances into the future taking into consideration the effects of depreciation and
15 retirements. Based upon my review, however, the capital project data was not entered into the
16 system planning model correctly.

17 **Q. WHAT ERROR DID YOU IDENTIFY IN THE SYSTEM PLANNER MODEL?**

18 A. In OPUC Data Request 128, Attachment D, PGE detailed monthly plant additions entered into
19 the System Planner model by function. While the total amount of annual capital was the same

^{10/} In the Matter of the Revised Tariff Schedules Applicable to Electric Service, OPUC Docket UE 111, Order No. 00-091 (Feb. 14, 2000) (citing In the Matter of the Application of U S WEST Communications, Inc., for an Increase in Revenues, Order No. 97-171 (noting that the Commission used a combination of historical and future data for the test year)); see OAR 860-022-0019(1)(D), renumbered from OAR 860-013-0075.

^{11/} Re Portland Gen. Elec. Co., 8 P.U.R.4th 393, 399-400 (Dec. 23, 1974).

^{12/} PGE's total forecast capital expenditures were provided in unredacted form in its response to Staff DR 128 Attachment D.

between the two data sources, the timing of those additions was different. Table 3, below, details the difference between the monthly data between the two sources. Other input errors could be observed with respect to the functionalization of expenditures in the System Planner model as well.

TABLE 3
Monthly Plant Additions \$
Variance System Planner vs. Project Data

	System Planner	Project Data AWEC DR 26	Variance
Jan 2018	17,435,114	19,269,778	(1,834,664)
Feb 2018	30,568,463	32,421,604	(1,853,141)
Mar 2018	27,495,093	28,879,281	(1,384,188)
Apr 2018	233,150,081	210,375,887	22,774,194
May 2018	24,843,873	27,007,373	(2,163,499)
Jun 2018	48,212,868	54,414,283	(6,201,415)
Jul 2018	27,124,832	34,343,828	(7,218,996)
Aug 2018	22,173,359	29,029,823	(6,856,465)
Sep 2018	42,140,318	40,342,048	1,798,270
Oct 2018	26,376,047	33,890,645	(7,514,598)
Nov 2018	27,953,937	35,142,648	(7,188,710)
Dec 2018	145,846,041	128,202,829	17,643,212
Annual	673,320,026	673,320,026	(0)

a. Rate Base Measurement Date

Q. WHAT RATE BASE MEASUREMENT DATE DOES PGE PROPOSE?

A. PGE proposes using a rate base measurement period of December 31, 2019.

Q. DO YOU AGREE WITH THIS MEASUREMENT DATE?

A. No. In order to have adequate ability to review and confirm the used and usefulness of the capital, I recommend establishing a rate base measurement date of October 31, 2018. This date is appropriate because it will correspond to the update cycle in the annual update tariff, as well as the approximate timing of when PGE typically updates its load forecast.

1 **Q. WHAT DID THE COMMISSION SAY IN ITS ORDER IN DOCKET UE 319 ABOUT**
2 **CAPITAL EXPENDITURES?**

3 A. Quoting its order in Avista's 2017 general rate case, the Commission stated that "parties
4 wishing to include plant not-yet-in-service as part of the proposed revenue requirement in
5 future rate cases ... [must] be prepared to explain such proposals with particularity and to
6 justify, via clear and convincing evidence, the circumstances providing the rationale for their
7 inclusion in their general rate case application."^{13/} My understanding of the Commission's
8 directive in this order was to echo parties' frustrations with Oregon utilities' capital forecasting
9 practices that can lead to the establishment of a capital budget that utilities can then fill with
10 whatever capital projects they choose, regardless of whether those projects have been reviewed
11 and found prudent. My recommendation to measure rate base as of October 1, 2018 helps
12 address this concern.

13 **Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?**

14 A. I relied on PGE's response to Staff Data Request 128, Attachment D, to calculate the impact of
15 this adjustment. I adjusted rate base by eliminating the incremental net plant in PGE's forecast
16 beyond October 31, 2018. Further, I estimated the impact on depreciation expense, based on
17 the incremental plant balances that were removed. Removing the projects forecast beyond
18 October 31, 2018 results in a \$173,799,978 reduction to gross plant, a \$61,721,833 increase to
19 depreciation reserves (calculated by taking 2/12ths of the 2018 depreciation and amortization
20 expense). I did not have the data to quantify the impacts of this adjustment on EDFIT or
21 depreciation expense, although those should be considered. The result of my analysis is a
22 \$11,583,802 reduction to revenue requirement.

^{13/} Docket No. UE 319, Order 17-511 at 13 (Dec. 18, 2017).

b. Field Voice Communications / Spectrum Projects

Q. DO YOU HAVE AN EXAMPLE TO ILLUSTRATE WHY A DECEMBER 31, 2018 RATE BASE MEASUREMENT DATE IS PROBLEMATIC?

A. Yes. The Field Voice Communications project was identified in the 2018 GRC and was originally expected to be placed into service in December 2017. In addition, acquisition of spectrum was also considered in conjunction with this project. Based on my workpapers from UE 319, the total capital forecast in the 2017 GRC for this collection of projects was \$ [REDACTED]^{14/}, with \$46,828,573 attributable to the Field Voice Communications project and \$6,046,386 attributable to spectrum acquisition.

Q. DID PGE FILE AN ATTESTATION THAT THE FIELD VOICE COMMUNICATIONS AND SPECTRUM PROJECTS HAD BEEN PLACED INTO SERVICE?

A. Yes. PGE filed an attestation on December 29, 2017 in UE 319, stating that the Field Voice Communications and Spectrum projects had been placed into service and were being used for their intended purposes.

Q. WHAT AMOUNT OF CAPITAL WAS PLACED INTO SERVICE FOR THESE PROJECTS?

A. While some capital was transferred to plant with respect to Field Voice Communications and Spectrum projects in 2017, the amount actually transferred to plant represented only a small fraction (32%) of the capital that PGE had forecast in the 2017 GRC, and which was included in rates that went into effect on January 1, 2018. As can be noted in the attachment to PGE's response to AWEC Data Request 106, only \$16,926,397 was transferred to plant with respect to these projects in 2018. For the Field Voice Communications project (P35938), the transfers to plant were \$8,996,015, only about 19.2% of the amount forecast in the rate case. The

^{14/} AWEC confirmed with PGE that it could use this figure in Mr. Mullins' UE 335 testimony.

1 Spectrum project was placed into service with total capital of \$5,938,311 for the 700mhz phase
2 (P36005) and \$1,992,070 for the 200mhz phase (P36354). Thus, while I have no reason to
3 doubt that PGE placed a portion of these projects into service, as attested, PGE's total capital
4 budget for these projects, and the amount included in rates on January 1, 2018, was overstated
5 by \$35,948,562. Parties had no meaningful opportunity to contest or review those amounts.

6 **Q. DID PGE ALSO INCLUDE THE FIELD VOICE COMMUNICATIONS PROJECTS IN**
7 **THIS CASE?**

8 A. Yes. The Field Voice Communications project represents a major portion of PGE's capital
9 forecast in this case, even though the project was already included in rates in the 2017 GRC.
10 In this case, PGE proposes to include \$33,449,021 in its budget for the Field Voice
11 Communications project. This is the approximate amount that had been included in rates on
12 January 1, 2018 but never actually placed into service.

13 **Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE FIELD VOICE**
14 **COMMUNICATIONS AND SPECTRUM PROJECTS?**

15 A. The circumstances surrounding the Field Voice Communications project further supports the
16 use of a rate base measurement period that allows for some review by the parties, as I have
17 recommended above.

18 Since PGE provided the attestation, however, I further recommend a disallowance in
19 the current case equal to the revenue requirement PGE will collect over the period January 1,
20 2018 through December 31, 2018, for the property that was included in rates but never actually
21 placed into service. Using the \$35,948,562 rate base amount described above, the impact of
22 this recommendation is a \$3,715,452 reduction to revenue requirement.

1 **c. Project Specific Adjustments**

2 **Q. PLEASE SUMMARIZE YOUR REVIEW OF MAJOR PROJECTS.**

3 A. I performed a project-specific review for major, discrete projects. My project-specific review
4 did not extend to non-discrete projects, such as blanket capital authorizations. Since the blanket
5 projects do not represent any particular project, it is not possible to review those on a project-
6 by-project basis. Accordingly, I reviewed each discrete project with a total capital budget
7 exceeding \$10,000,000. For smaller projects, I considered those as non-discrete, since due to
8 the large volume of projects, it is not possible or practicable to perform a project-by-project
9 review of those items. The projects I reviewed are:

- 10 • P35619 CET Install Oracle CC&B/MDM Systems
- 11 • P35679 Construct Marquam Project
- 12 • P35938 Field Voice Communications System
- 13 • P35329 Blue Lake/Gresham - System Upgrades
- 14 • P35980 PCB Transformer Replacement
- 15 • P36394 Vintage Vehicle Replacement II
- 16 • P22449 Colstrip Capital Project

17 **Q. DO YOU CONTEST THE PRUDENCE OF ANY FORECAST INVESTMENT?**

18 A. While I do not contest the prudence of any project, I have identified a number of
19 inconsistencies between the capital forecast and the underlying documentation. In addition, I
20 also consider the vehicle replacement program as a discrete project, and propose to use a
21 budget that is more in line with historical expenditures associated with vehicle replacement.

22 **Q. WHAT DID YOU DISCOVER WITH RESPECT TO YOUR REVIEW OF PROJECT**
23 **CET INSTALL ORACLE CC&B/MDM SYSTEMS (CUSTOMER TOUCHPOINTS)?**

24 A. Project P35619 represents the Customer Touchpoints projects and was extraordinarily
25 expensive. In AWEC Data Request 107, I conducted discovery with respect to this project.
26 Based on that discovery, it appears that the Customer Touchpoints project has been severely

1 over budget. PGE indicates that it currently expects the project to cost \$153,942,650, which is
2 significantly higher than the initial estimates for this project of \$ [REDACTED], noted in the
3 project justification forms. Further, that amount is much higher than the \$ [REDACTED]
4 identified in the project data provided in response to AWEC Data Requests 26.

5 **Q. HOW MUCH CAPITAL HAS BEEN SPENT WITH RESPECT TO THE CUSTOMER**
6 **TOUCHPOINTS PROJECT?**

7 A. According to Attachment B to PGE's response to AWEC Data Request 107, \$129,001,910 had
8 been spent through April of 2018.

9 **Q. HAS THE CUSTOMER TOUCHPOINTS PROJECT BEEN PLACED INTO**
10 **SERVICE?**

11 A. Yes. Both applications underlying the Customer Touchpoints projects went live on May 14,
12 2018.

13 **Q. DO YOU CONTEST THE AMOUNT OF CAPITAL PGE HAS INCLUDED FOR THE**
14 **CUSTOMER TOUCHPOINTS PROJECT?**

15 A. No. However, I recommend that PGE be limited to recovery plant additions identified in
16 PGE's initial filing, even though it currently estimates that it will likely further exceed its
17 budget on the Customer Touchpoints project. Based on PGE's Response to AWEC Data
18 Request 116, there are legitimate questions about some activities late in the development
19 process leading to these budget overages. Because PGE has not specifically requested the
20 budget overages in this case, I have not reviewed those amounts for the purpose of preparing
21 this testimony.

1 **Q. WHAT HAVE YOU DISCOVERED WITH RESPECT TO YOUR REVIEW OF THE**
2 **MARQUAM PROJECT?**

3 A. The Marquam Project represents a series of infrastructure improvements around the south
4 waterfront. I conducted discovery with respect to this project in AWEC Data Request 108,
5 where PGE describes the project as “a new 115kV state-of-the-art substation and two feeders.”

6 **Q. WHEN IS THE MARQUAM PROJECT EXPECTED TO BE PLACED INTO**
7 **SERVICE?**

8 A. The majority of the capital for this project was expected to be placed into service in April of
9 2018. Based on the attachment provided with AWEC Data Request 108, the majority of the
10 capital was actually transferred to plant in April. This leads me to believe that the project is on
11 schedule and within budget. Thus, I do not oppose using PGE’s budget for the Marquam
12 project in rate base.

13 **Q. PLEASE SUMMARIZE YOUR REVIEW OF THE FIELD VOICE**
14 **COMMUNICATIONS PROJECT.**

15 A. I conducted discovery with respect to the Field Voice Communications project in AWEC Data
16 Request 131. Based on the adjustment related to this project discussed above, I am not
17 proposing any additional adjustments based upon my review of that discovery.

18 **Q. PLEASE SUMMARIZE YOUR REVIEW OF THE BLUE LAKE/GRESHAM -**
19 **SYSTEM UPGRADES PROJECT.**

20 A. The majority of this project was expected to be placed into service in December 2018, and for
21 that reason, was not considered in my analysis based upon the rate base measurement date
22 identified above. Notwithstanding, an initial phase of this project was budgeted to go into
23 service in the spring of 2018, and I have not identified any reason to contest those amounts.

Q. PLEASE SUMMARIZE YOUR REVIEW OF THE VINTAGE VEHICLE REPLACEMENT PROGRAM.

A. In reviewing PGE's vintage vehicle replacement program, I reviewed actual spending on vehicles over the three-year period 2015 through 2017 to evaluate the reasonableness of PGE's capital budget. I have observed that the capital budgets for this capital category have varied materially year to year, and have actually declined in recent years. Table 4 details the historical rate of spending for this project based on the data provided in response to AWEC Data Request 106.

TABLE 4
Historical Spending on Vintage Vehicle Replacement \$

2015	2016	2017	Avg	2018 Forecast	Adj.
12,257,743	8,332,634	7,678,839	9,423,072		(2,080,674)

Based on this historical pattern, my recommendation is to use the three-year average for budgetary purposes. After prorating for the shortened 10-month forecast period, the impact of this recommendation is a \$179,206 reduction to revenue requirement.

Q. PLEASE SUMMARIZE YOUR REVIEW OF THE PCB TRANSFORMER REPLACEMENT PROJECT.

A. I conducted discovery with respect to the PCB Transformer Replacement project in AWEC Data Request 129. As noted in that response, PGE has only replaced 2,683 out of 6,400 transformers identified with respect to the project. Based on PGE's response, I do not contest the budget for this project, at this time, since there are still a large number of transformers that need to be replaced.

1 **Q. PLEASE SUMMARIZE YOUR REVIEW OF THE COLSTRIP CAPITAL PROJECT.**

2 A. PGE forecasts \$ [REDACTED] of capital with respect to the Colstrip Capital project in AWEC
3 Data Request 133. This amount represents ongoing capital maintenance of the facility which is
4 managed by Talen Energy. Given the approximate 296 MW of capacity PGE receives from
5 Colstrip, the magnitude of that ongoing capital investment is significant. At the current rate of
6 ongoing capital maintenance at the Colstrip plant, ratepayers might be stuck with hundreds of
7 millions of dollars in incremental stranded costs at the end of Colstrip's waning useful life.
8 Accordingly, I viewed it to be relatively important to have a clear understanding of the
9 economics of these ongoing capital investments from the perspective of ratepayers.

10 **Q. DID PGE PERFORM ANY ECONOMIC ANALYSIS WITH RESPECT TO THE**
11 **ONGOING CAPITAL MAINTENANCE AT COLSTRIP?**

12 A. No. In its response AWEC Data Request 133, PGE stated "PGE's operating agreement with
13 Talen allows for Talen to determine annually what capital work is required to operate the plant
14 safely and reliably within its environmental permitting requirements through its planned
15 operating lifetime."

16 **Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE COLSTRIP CAPITAL**
17 **PROJECTS?**

18 A. While I do not oppose PGE's capital budget for Colstrip at this time, I am concerned that PGE
19 is doing very little to consider the economics of these ongoing capital maintenance
20 investments. In its rebuttal testimony, PGE should perform such a review to demonstrate that
21 the \$ [REDACTED] rate of investment at Colstrip represents an efficient use of ratepayer money.

d. Non-discrete Capital Additions

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF NON-DISCRETE CAPITAL ADDITIONS.

A. For those projects which could not be independently verified, I looked to historical spending levels by function to determine a reasonable amount of spending by function in the forecast period. When making this determination, in relation to historical levels, the discrete major projects were removed from the historical data.

Q. WHAT WAS THE RESULT OF YOUR ANALYSIS?

A. Table 4, below, summarizes the results of my analysis for non-discrete capital additions.

TABLE 4
Non-Discrete Capital Forecast Analysis
Proposed Annual Expenditure Rate By Function \$
Source: AWEC Data Request 106

Function	2015	2016	2017	Average	2018 Forecast	Adjustment
Distribution	127,244,120	149,704,998	203,513,001	160,154,040	224,788,384	(21,275,383)
General	54,210,927	53,421,194	75,283,987	60,972,036	48,542,373	26,741,614
Other Prod.	22,504,082	37,359,459	34,069,444	31,310,995	23,790,548	10,278,897
Intangible	16,425,506	15,633,374	21,770,986	17,943,289	39,423,839	(17,652,853)
Hydro	11,795,877	20,436,592	8,417,303	13,549,924	27,886,892	(19,469,589)
Transmission	4,704,304	5,530,025	12,193,220	7,475,850	36,610,746	(24,417,526)
Steam Prod.	1,824,630	744,379	404,507	991,172	378,233	26,274
<i>Total</i>	<i>238,709,446</i>	<i>282,830,021</i>	<i>355,652,449</i>	<i>292,397,305</i>	<i>401,421,016</i>	<i>(45,768,567)</i>

As can be seen, PGE's forecast for non-discrete capital increases dramatically in 2018 relative to historical levels. The rate of capital expenditures on non-discrete capital has been accelerating, and between 2015 and 2018 (just a few short years), PGE's forecast would result in nearly doubling the rate of capital expenditures for non-discrete capital projects.

Q. WHAT DO YOU RECOMMEND?

A. I recommend using the 2017 rate of expenditures to establish the budgeted level of rate base in this matter. Under this approach, PGE would slow its rate of capital spending to be consistent

1 with the rate experienced in 2017, which is still higher than the 2015-2017 average. While I
2 believe there is merit in using the three-year average to determine the capital expenditure rate,
3 use of the 2017 rate is as an approach is reasonable given the overall circumstances in this
4 case. This adjustment is further prorated to reflect only ten months of non-discrete capital
5 additions, since the non-discrete capital additions beyond October 31, 2018 were removed in
6 my adjustment related to the rate base measurement date above.

7 **Q WHAT IS THE IMPACT OF YOUR ADJUSTMENT?**

8 A. After prorating, the impact is a reduction of \$38,140,472 in capital additions forecast over the
9 period January 1, 2018 through October 31, 2018.

10 **Q. DOES THIS ADJUSTMENT OVERLAP WITH DR. HELMAN'S ADJUSTMENT**
11 **WITH RESPECT TO LABOR?**

12 A. I assume that the capital portion of Dr. Hellman's adjustment is offsetting to this capital
13 adjustment, and thus offsets this rate base reduction by \$11,814,081. It is also necessary to
14 exclude incremental depreciation, depreciation reserves, and deferred taxes. I expect those
15 impacts to be relatively small, and have not considered those for this round of testimony. After
16 adjusting for Dr. Hellman's recommendations, the result is a \$26,326,392 reduction to rate
17 base and a corresponding \$2,720,956 reduction to revenue requirement.

18 **IV. ACCUMULATED DEFERRED INCOME TAXES**

19 **Q. WHAT ARE ACCUMULATED DEFERRED INCOME TAXES?**

20 A. Deferred tax assets and liabilities are, where appropriate, reflected in rate base valuation as
21 Accumulated Deferred Income Taxes ("ADIT"). In revenue requirement, ADIT is considered
22 a source—or use—of "no-cost capital." If a utility recognizes a deduction for tax accounting
23 purposes earlier than the expense would otherwise be recognized for ratemaking purpose, the

1 utility is allowed to retain the cash benefits of the early deduction, treating it as a source of
2 financing. Depreciation expense is the most common example. For tax purposes, a utility is
3 often provided with the ability to depreciate property using *liberalized*, accelerated
4 depreciation methodologies. For regulatory purposes, however, depreciation expense is
5 calculated based largely on straight-line methodologies—albeit calculated in complex
6 depreciations studies—which typically assume longer lives. Thus, a utility may claim tax
7 benefits associated with the cost of utility property that is, in most instances, earlier than
8 reflected in the tax expenses uses for ratemaking. A well-known example of this timing
9 difference is bonus depreciation, which a utility may claim for tax purposes, but must
10 depreciate the eligible facility for regulatory purposes on a straight-line basis. To account for
11 this timing difference, the cash benefit received by the utility as a result of the different
12 depreciable lives is treated as a source of no-cost capital, and deducted from rate base through
13 ADIT.

14 **Q. PLEASE PROVIDE AN OVERVIEW OF YOUR ADJUSTMENTS RELATED TO**
15 **ADIT.**

16 A. The Exhibit PGE/200 workpaper titled “2019 Deferred Tax Detail” details all of the deferred
17 tax amounts PGE proposes to include in revenue requirement in this matter, although in
18 response to AWEC Data Request 10, Attachment A, PGE updated the information in that
19 workpaper.^{15/} I contest several ADIT items.

^{15/} Exhibit AWEC/205 at 4-7 (PGE Resp. to ICNU DR 010).

1 **a. Production Tax Credit Carryforwards**

2 **Q. WHAT ARE PRODUCTION TAX CREDITS CARRYFORWARDS?**

3 A. Internal Revenue Code (“IRC”) § 45, establishes the availability of production tax credits for
4 generation from certain renewable sources of power supply.^{16/} Production tax credits are
5 considered to be a general business credit, the utilization of which are governed by IRC § 38.
6 Under that section, a general business credit may not reduce a business’s tax liability below
7 25% of its regular tax liability.^{17/} In addition, a general business credit may not reduce a
8 business’s tentative minimum tax below its tentative minimum tax, the tax computed for
9 purposes of the alternative minimum tax.^{18/} To the extent that a credit is not utilized in any
10 particular tax year, however, it may be carried forward to offset tax liability in future tax years
11 for a period of twenty years.^{19/}

12 **Q. WHAT AMOUNT OF PRODUCTION TAX CREDIT CARRYFORWARDS DOES THE**
13 **COMPANY PROPOSE IN RATE BASE IN THIS MATTER?**

14 A. According to the workpaper titled “2018 Deferred Tax Detail.xlsx” provided along with
15 Exhibit No. PGE/200, the Company proposes to include \$69,489,835 in ADIT for production
16 tax credit carryforwards. In UE 319, PGE forecast a production tax credit carryforward
17 balance of \$60,019,000. That is in contrast to the balance of \$49,582,793 included in PGE’s
18 tax provision for December 31, 2017.

^{16/} IRC § 45

^{17/} IRC § 38

^{18/} Id.

^{19/} Id.

1 **Q. WHY DO YOU PROPOSE TO REMOVE PRODUCTION TAX CREDITS FROM**
2 **ADIT IN THIS MATTER?**

3 A. I discuss three general reasons why it is not appropriate to include production tax credit
4 carryforwards in ADIT in this matter. First, as detailed above, PGE has historically overstated
5 the production tax credit carry forward balances in prior rate cases, relative to the amounts that
6 have actually been included on its tax provision. Second, these carryforwards represent
7 significant balances that were not considered in the request for proposal processes where the
8 underlying renewable resources were selected. Third, a production tax credit carryforward is
9 created by the Company's inability to generate sufficient taxable income in any given tax year,
10 not a timing difference in the recognition of costs and revenues between tax and regulatory
11 accounting methodologies.

12 **Q. WHAT COMPANY RESOURCES GENERATE PRODUCTION TAX CREDITS?**

13 A. Production tax credits are primarily produced by the Biglow and Tucannon River wind
14 facilities, although the Company generates a small amount of production tax credits from the
15 Oak Grove solar project. In addition, the production tax credits generated from Phase 1 of the
16 Biglow wind facility begin to phase out later this year, followed by the phasing out of credits
17 for Biglow Phases 2 and 3 in 2019 and 2020, respectively. As that happens, these large
18 deferred tax asset balances will decline. Although if PGE proceeds with building a new
19 renewable resource, we will likely see the carryforward balances growing to even higher
20 levels.

21 **Q. WERE THESE RESOURCES SELECTED BASED ON PGE'S REPRESENTATION**
22 **THAT THE PRODUCTION TAX CREDITS WOULD BE FULLY UTILIZED?**

23 A. Yes. For instance, in justifying the prudence for Tucannon, PGE noted that the top three
24 factors it analyzed in the request for proposals that ultimately led to the selection of Tucannon

1 were “capacity, transmission costs and risks, and the ability to use production tax credits.”^{20/}

2 To my knowledge, PGE did not consider that it would be unable to utilize the credits generated
3 from these facilities, when considering whether to make the investments.

4 **Q. ARE THE TAX CREDIT CARRYFORWARDS TIED TO TIMING DIFFERENCES**
5 **BETWEEN TAX AND REGULATORY ACCOUNTING?**

6 A. No. A production tax credit carryforward is not created as a result of any difference between
7 tax and regulatory accounting. It is driven by the ability of the Company to generate sufficient
8 taxable income in a particular tax year to utilize the credits. If the Company’s revenues were
9 lower than expected due to unfavorable market conditions, for example, such a scenario could
10 reduce the taxable income of the Company, resulting in the creation of production tax credit
11 carryforwards. Plus, production tax credits are not covered under the IRS normalization rules,
12 and for that reason there is no statutory requirement to include those balances in rate base.

13 **Q. DOES THE COMPANY HAVE AN INCENTIVE TO UTILIZE PRODUCTION TAX**
14 **CREDIT CARRYFORWARDS ON ITS TAX RETURN?**

15 A. No. If production tax credit carryforwards continue to be reflected in rate base, the Company
16 has little incentive to utilize those assets because it earns a return on these tax assets.

17 **Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF REMOVING**
18 **PRODUCTION TAX CREDIT CARRYFORWARDS FROM ADIT?**

19 A. Removing production tax credit carryforwards from ADIT results in a revenue requirement
20 reduction of \$7,182,100 reduction to revenue requirement.

21 **Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?**

22 A. Yes. If the Commission disagrees with my recommendation above, then at a minimum, it
23 should reduce PGE’s assumed carryforward balance to recognize the Company’s tendency to

^{20/} Docket No. UE 283, PGE/400 at 7:17-19.

1 over-forecast that amount in rates. I recommend that PGE's production tax credit carryforward
2 balance be assumed to equal the \$49,582,793 it included in its tax provision for December 31,
3 2017. Reducing PGE's assumed carryforward balance will also recognize the anticipated
4 reduction to this balance in the near term as production tax credits from Biglow 1 begin rolling
5 off.

6 **b. Accrued Vacation**

7 **Q. WHAT AMOUNT OF ADIT HAS PGE INCLUDED IN REVENUE REQUIREMENT**
8 **RELATED TO ACCRUED VACATION?**

9 A. PGE included ADIT associated with accrued vacation in the amount of \$4,842,278.

10 **Q. IS THE ADIT ASSOCIATED WITH ACCRUED VACATION APPROPRIATELY**
11 **INCLUDED IN RATE BASE?**

12 A. No. ADIT related to accrued vacation arises due to a timing difference of when those costs are
13 incurred for GAAP purposes and when they are deductible for tax purposes. For GAAP
14 purposes, an amount is deducted against operating revenues when an employee earns the
15 vacation days. For tax purposes, those amounts are only deducted when paid, i.e., when the
16 employee actually uses the accrued vacation days. Since ratepayers do not receive a financing
17 benefit as a result of this timing difference through a reduction in rate base, it is not appropriate
18 for ratepayers to incur the deferred tax consequences resulting from such timing difference.

19 **Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT RELATED TO ACCRUED**
20 **VACATION?**

21 A. Removing the \$4,842,278 ADIT amount from rate base results in a reduction of \$500,472
22 reduction to revenue requirement.

1 **c. Management Stock Incentive Plan**

2 **Q. WHAT AMOUNT OF ADIT HAS PGE PROPOSED TO INCLUDE RELATED TO ITS**
3 **MANAGEMENT STOCK INCENTIVE PLAN?**

4 A. PGE has proposed to include ADIT of \$3,502,315 related to its management stock incentive
5 plan.

6 **Q. WHAT DO THESE ADIT AMOUNTS REPRESENT?**

7 A. PGE provided an overview of these amounts in response to AWEC Data Request 100.^{21/}
8 According to PGE these amounts “represent[] the timing difference of when the costs of stock
9 incentive plans are recorded for book versus tax. For book purposes these costs are expensed,
10 straight line, over the vesting period. For tax purposes, the costs are deducted on the vesting
11 date. The difference in timing between when the expense is recognized for book and tax
12 purposes, creates a temporary difference that results in a deferred tax asset or liability.”

13 **Q. ARE THESE AMOUNTS APPROPRIATELY CONSIDERED FOR RATEMAKING?**

14 A. No. Management stock incentive plans are typically not considered for ratemaking, since they
15 are often directly tied to earnings, which benefit shareholders.

16 **Q. WHAT IS THE IMPACT OF REMOVING THOSE AMOUNTS?**

17 A. Removing the ADIT associated with the management stock incentive plan results in a
18 \$361,981 reduction to revenue requirement.

19 **d. Boardman Severance**

20 **Q. WHAT AMOUNT OF ADIT HAS PGE INCLUDED RELATED TO BOARDMAN**
21 **SEVERANCE PAYMENTS?**

22 A. PGE includes \$2,774,733 of ADIT associated with Boardman Severance payments.

^{21/} Exhibit AWEC/205 at 16 (PGE Resp. to AWEC DR 100).

1 **Q. WHAT DOES THIS AMOUNT REPRESENT?**

2 A. This amount is tied to the tax timing of the Boardman severance payments, which are currently
3 being collected through Schedule 145. In response to AWEC Data Request 99, PGE
4 confirmed that the forecasted severance payments related to the cessation of coal-fired
5 operations at Boardman are being collected through PGE Schedule 145 and are not included in
6 the UE 335 revenue requirement.

7 **Q. IS THIS AMOUNT APPROPRIATELY CONSIDERED IN REVENUE**
8 **REQUIREMENT?**

9 A. No. Since the severance payments are not being considered in revenue requirement, the
10 amounts should also be excluded from ADIT. In addition, the way that the severance expense
11 is being booked in PGE's financial statements, which gives rise to the ADIT, has no bearing on
12 the way PGE considers those costs in rates.

13 **Q. WHAT IS THE IMPACT OF THIS ADJUSTMENT?**

14 A. Removing the Boardman Severance ADIT amount results in a \$286,782 reduction to revenue
15 requirement.

16 **e. Provision for Injury and Damages**

17 **Q. WHAT AMOUNT OF ADIT HAS PGE CONSIDERED WITH RESPECT TO ITS**
18 **PROVISION FOR INJURIES AND DAMAGES?**

19 A. PGE's rate base includes an ADIT item in the amount of \$2,438,685 related to its provision for
20 injuries and damages. For tax purposes, the injury and damages amounts are recorded when it
21 becomes probable that actual liability will result. For tax purposes the injuries and damages
22 amounts are deductible when paid.

1 **Q. IS ADIT RELATED TO INJURIES AND DAMAGES APPROPRIATELY**
2 **CONSIDERED IN REVENUE REQUIREMENT?**

3 A. No. In the case of injuries and damages, the regulatory treatment follows the tax treatment, in
4 that the cost is recognized based on the timing of when PGE actually makes the liability
5 payment and does not correspond to the timing used for book purposes.

6 **Q. WHAT IS THE IMPACT OF REMOVING THIS ADIT ITEM?**

7 A. Eliminating this ADIT item results in a \$252,050 reduction to revenue requirement.

8 **V. MISCELLANEOUS REVENUE REQUIREMENT ISSUES**

9 **a. Depreciation Reserves**

10 **Q. WHAT HAVE YOU DISCOVERED WITH RESPECT TO DEPRECIATION**
11 **RESERVES?**

12 A. In response to AWEC Data Request No. 002, PGE confirmed that its depreciation reserves
13 were understated by \$19,800,000 due to a calculation error. Applying this correction reduces
14 revenue requirement by \$2,046,423.

15 **b. Trojan Decommissioning Trust**

16 **Q. WHAT AMOUNT OF AMORTIZATION DOES PGE REPORT FOR THE TROJAN**
17 **NUCLEAR DECOMMISSIONING TRUST BALANCES.**

18 A. In PGE's initial filing it assumed \$2,500,000 of amortization associated with Trojan Nuclear
19 Decommissioning Trust ("NDT") balances.

20 **Q. HOW DID PGE CALCULATE THAT AMOUNT OF NDT AMORTIZATION?**

21 A. In response to AWEC Data Request 120, PGE described the methodology that it used to
22 calculate that level of amortization. PGE states that balances, expected rate of return on trust
23 assets, cost estimates, and other parameters were established in a model designed to bring the
24 balance of the trust down to zero by 2034.

1 **Q. DOES THE \$2,500,000 OF AMORTIZATION BRING THE BALANCE DOWN TO**
2 **ZERO BY 2034?**

3 A. Based on the level of amortization PGE proposes, the balance will decline to well below zero
4 by 2034. In its response to AWEC Data Request 120, PGE confirmed this fact, and noted that
5 the actual amount of amortization necessary to bring the balance down to zero is \$1,800,000.^{22/}

6 **Q. WHY DOES PGE PROPOSE A HIGHER AMOUNT OF AMORTIZATION?**

7 A. PGE's justification for the higher amount of amortization is that it is "currently in the process
8 of renewing our Nuclear Regulatory Commission license at Trojan for an additional 40 years,
9 which will add considerable uncertainty associated with the spent nuclear fuel at the Trojan
10 site"^{23/}

11 **Q. DO YOU AGREE WITH PGE'S PROPOSAL?**

12 A. No. If the life is extended for an additional 40 years, that would spread the decommissioning
13 cost over a longer period, which would justify a lower level of amortization. In addition, the
14 current balances will be subject to interest over a longer period, reducing the ratepayer expense
15 associated with the decommissioning expense.

16 **Q. WHAT IS YOUR RECOMMENDATION?**

17 A. I recommend that the Trojan NDT amortization of \$1,800,000 be used in establishing revenue
18 requirement, resulting in a \$725,069 reduction to revenue requirement.

^{22/} Exhibit AWEC/205 at 29 (PGE Resp. to AWEC DR 120)

^{23/} Id.

1 **c. Customer Touchpoints R&D Tax Credit**

2 **Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO PGES ABILITY TO**
3 **CLAIM AN R&D TAX CREDIT FOR THE TOUCHPOINTS SYSTEM.**

4 A. Under IRC § 41(d)(4)(E), internal use software of a utility may generally not be claimed
5 toward an R&D tax credit. The cost of developing software for an accounting system, for
6 example, has traditionally not been considered a qualified research expenditure and thus
7 eligible towards the credit.

8 On October 4, 2016, however, the IRS published new regulations that clarify and
9 provide exceptions to the general rules surrounding internal use software. Under the new
10 regulations, software developed to enable a taxpayer to interact with third parties or allow third
11 parties to initiate functions or review data on the taxpayer's system are eligible and may be
12 claimed as a qualified research expenditure.

13 For utilities, this means that a fairly broad range of utility applications, which were
14 formerly considered to be internal use software, may now be eligible qualified research
15 expenditures. Costs associated with building EIM-related applications, which interface with
16 the California Independent System Operator, for example, would likely be eligible under this
17 regulation. Further, applications such as the Touchpoints projects, which allow third-party
18 ratepayers to review billing data on the utility's system, and provide functions that allow the
19 utility to interact with ratepayer load will also partially qualify for the credit. In Exhibit
20 AWEC/204, I have attached the Federal Register notice which provides an outline the new
21 internal use software regulation.

22 For applications that contain elements that are considered internal use software and
23 other elements which are outwardly facing, only the portion of the software which are

1 outwardly facing may be claimed toward the credit. The regulations, however, provide a safe
2 harbor applicable to dual use software, where 25% of the expenditures may be considered
3 toward the credit, provided that at least 10% of the project was related to outward facing
4 functionality.

5 **Q. DID PGE INCLUDE ANY R&D TAX CREDITS IN ITS FILING?**

6 A. No. Based on my understanding of the complexity involved in the Touchpoints project and the
7 nature of the interaction with ratepayers, however, I believe a portion of the project costs will
8 qualify for the R&D tax credit under the safe harbor provision. Thus, I believe PGE will be
9 able to claim 25% of the cost of the Touchpoints project as contract research expenditures
10 when calculating its R&D tax credit. Given that the project costs \$130,571,018, it must
11 contain elements which are highly technical, requiring innovative solutions to address the
12 specific needs of PGE's system and its customers.

13 **Q. WHAT DO YOU RECOMMEND?**

14 A. I recommend that PGE engage its tax provider to conduct an R&D tax credit study to review
15 all of the software projects that PGE has placed into service since the new regulations were
16 issued to determine if those projects are eligible to be claimed towards the 25% Safe Harbor.

17 In this proceeding I propose including a R&D tax credit amount for the Touchpoints
18 project, based on the calculation provided in Exhibit AWEC/201, Page 5. Based on that
19 workpaper I calculate a credit equal to \$2,346,688, which equates to a revenue requirement
20 reduction of \$3,322,482. The revenue requirement adjustment is larger than the credit amount
21 because it is stated on a post-tax basis, and similar to production tax credits, must be grossed
22 up using the conversion factor to determine the pre-tax revenue requirement value.

d. UE 283 Incentives Adjustment

Q. PLEASE DESCRIBE THE INCENTIVES ADJUSTMENT TO RATE BASE THAT WAS STIPULATED IN DOCKET UE 283.

A. In Docket UE 283, it was determined that PGE had improperly capitalized past incentives expenditures, which are traditionally not considered for ratemaking in Oregon. To resolve that issue, PGE agreed to a \$10,000,000 reduction to rate base, which was to be amortized, as a benefit, to results over a 20-year period.

Q. DID PGE CONSIDER THAT AMORTIZATION IN THIS CASE?

A. No. PGE reduced rate base for this settlement adjustment, but did not consider the corresponding \$500,000 of annual amortization. PGE confirmed this error in response to AWEC Data Request 121.

Q. WHAT IS THE IMPACT OF THIS CORRECTION?

A. Incorporating the amortization of the incentives adjustment into revenue requirement results in a \$507,906 reduction to revenue requirement, after considering revenue sensitive costs.

e. Dispatchable Generation Regulatory Asset

Q. WHAT REGULATORY ASSET HAS PGE INCLUDED WITH RESPECT TO DISPATCHABLE GENERATION?

A. PGE included a regulatory asset in rate base in the amount of \$11,818,000 associated with dispatchable generation. In AWEC Data Request 122, PGE was requested to provide further clarification of what this amount represents. PGE responded that PGE's Dispatchable Standby Generation ("DSG") program pays participating customers owning large, diesel-powered generators for fuel and routine maintenance costs in exchange for access to generator output during times when the PGE grid needs extra power.^{24/}

^{24/} Exhibit AWEC/205 at 31 (PGE Resp. to AWEC DR 122).

1 **Q. DID YOU REQUEST THAT PGE IDENTIFY THE ORDER WHERE THIS**
2 **PURPORTED REGULATORY ASSET WAS APPROVED?**

3 A. Yes. In AWEC Data Request 122, PGE suggested that this regulatory asset was approved in
4 Docket No UE 115, PGE's 2001 GRC, on page 11 of Order 01-777.

5 **Q. DID YOU REVIEW THAT ORDER?**

6 A. Yes. However, I have not identified anywhere in that order where a regulatory asset associated
7 with dispatchable generation as described by PGE was approved.

8 **Q. DID YOU REVIEW PGE'S CALCULATION UNDERLYING THE REGULATORY**
9 **ASSET BALANCE?**

10 A. Yes. PGE provided Confidential Attachment A to AWEC Data Request 122.^{25/} That
11 workpaper, however, contained only hard coded outputs from the System Planner model and
12 did not provide any meaningful information that could be used to determine how the regulatory
13 asset balance was calculated.

14 **Q. WHAT IS YOUR RECOMMENDATION?**

15 A. I have identified no evidence that a regulatory asset associated with dispatchable standby
16 generation is appropriately in rate base. Further, PGE has been unable to identify what
17 historical costs have been included in this asset. Accordingly, I recommend that the
18 dispatchable generation regulatory asset be removed from rate base.

19 **Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?**

20 A. Removing the dispatchable generation regulatory asset results in a \$11,818,000 reduction to
21 rate base, and a corresponding, \$1,221,446 reduction to revenue requirement.

^{25/} Id.

1 **f. Boardman Severance Payments**

2 **Q. WHAT ISSUE HAVE YOU IDENTIFIED WITH RESPECT TO BOARDMAN**
3 **SEVERANCE PAYMENTS?**

4 A. In response to AWEC Data Request 01, PGE's workpaper showed that it is increasing the
5 depreciation reserves for the amount of amortization through the Schedule 145 that is
6 attributable to Boardman severance payments. PGE has been undertaking this practice since
7 the severance amount of \$2,266,836 per year was included in annual adjustments to the reserve
8 balance in July 2015. By October 31, 2018, the accumulated balance of these funds is
9 \$5,289,276.

10 **Q. WHY IS PGE MAKING THIS ADJUSTMENT?**

11 A. If I understand correctly, PGE includes the amortization of Schedule 145 revenues attributable
12 to decommissioning costs in its accumulated reserve balance. Unlike the decommissioning
13 expense, however, PGE is not allowed to include the severance accrual in the plant balance for
14 accounting purposes, and thus, is removing those balances from the reserve balance.

15 **Q. WHERE ARE THE BALANCES RELATED TO SEVERANCE PAYMENTS BEING**
16 **TRACKED?**

17 A. Order 11-242 in Docket No. UE 230 did not describe whether a carrying charge should accrue
18 on the revenues collected to cover incremental decommissioning expenses through Schedule
19 145, or whether those balances should be tracked as an offset to rate base. By including the
20 incremental reserve accumulation associated with the decommissioning revenues in the net
21 plant balance, it was my understanding that the funds collected under Schedule 145 were being
22 considered in rate base. Since PGE is applying an adjustment to remove the amounts collected
23 for severance payments, however, the portion of the Schedule 145 revenues attributable to the

1 severance payments are not being considered in net plant and ratepayers are not receiving any
2 carrying charge on those balances.

3 **Q. WHAT DO YOU RECOMMEND?**

4 A. I recommend that PGE establish a separate reserve sub-account to house the accumulated
5 Boardman severance revenues, and apply that account as an offset to rate base.

6 **Q. WHAT IS THE REVENUE REQUIREMENT IMPACT OF THIS**
7 **RECOMMENDATION?**

8 A. Reclassifying the accumulated severance payment reserves into rate base results in a \$546,671
9 reduction to revenue requirement.

10 **VI. PERMANENT DIRECT ACCESS PROGRAM**

11 **Q. PLEASE SUMMARIZE YOUR TESTIMONY ON PGE'S DIRECT ACCESS**
12 **PROGRAM.**

13 A. Beginning on Exhibit PGE/1300, Page 36, Line 7, PGE describes a number of changes to its
14 Permanent Direct Access program (also known as its long-term opt-out program). Just like
15 Oregon's Renewable Portfolio Standard ("RPS") and energy efficiency policies, direct access
16 plays an important role in Oregon's state energy policy. The specific changes PGE has
17 proposed, however, would have the effect of invalidating the permanent direct access program,
18 and therefore, should not be adopted. Unlike the program of other electric utilities in the state,
19 PGE's permanent direct access program has been successful, and for that reason, it is not
20 necessary to make sweeping changes at this time. In terms of an overall ratemaking policy, my
21 view is that a primary focus should be to provide departing ratepayers with an appropriate price
22 signal, while protecting non-participating customers. If a customer can depart from the
23 utility's system to free-up capacity on the growing utility's system, that should be viewed as a

1 positive, particularly when the departing customer may procure power with preferred
2 environmental attributes.

3 **Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.**

4 A. My recommendation has three elements. First, I recommend that the existing cap on PGE's
5 permanent direct access program be eliminated. Second, I recommend that the Commission
6 decline to approve the 10-year transition adjustment period proposed by PGE. Third, I
7 recommend that the calculation of the transition adjustment be modified to consider the value
8 of freed-up capacity when PGE is in a capacity-short position.

9 **a. Permanent Direct Access Program and PGE's Proposed Changes**

10 **Q. PLEASE PROVIDE SOME BACKGROUND ON PGE'S PERMANENT DIRECT**
11 **ACCESS PROGRAM.**

12 A. PGE's permanent direct access program has been in place since 2002.^{26/} While it has
13 undergone some modifications since then, its basic structure remains the same. Customers
14 with loads of at least one average MW ("aMW") have the option to leave the Company's cost
15 of service rates permanently by paying five years of transition charges, which represent the
16 fixed generation costs stranded by the customer's departure, minus the value of energy freed-
17 up also by that departure. Customers may also return to cost-of-service rates by providing at
18 least three years' notice. Prior to development of PGE's long-term opt-out program, direct
19 access, and the Legislature's goal expressed in statute to develop a working competitive
20 electricity market, was entirely unsuccessful.

21 PGE's long-term opt-out program has benefitted customers and Oregon's energy policy
22 in a number of ways. It has provided an additional option to the Company's largest customers

^{26/} See PGE Adv. 02-17.

1 who are the most sophisticated about their energy use and, therefore, have the means to operate
2 successfully on the open market, all while protecting non-participating customers from undue
3 cost-shifts. It has furthered state energy policy, as many direct access customers pursue
4 corporate sustainability goals and purchase renewable energy above and beyond what they
5 would be required to purchase under Oregon's RPS. It has also benefitted the state
6 economically by providing a low-cost alternative to Oregon's energy-intensive industries that
7 operate in competitive global markets.

8 **Q. HOW DOES PGE PROPOSE TO MODIFY ITS PERMANENT DIRECT ACCESS**
9 **PROGRAM IN THIS CASE?**

10 A. PGE proposes one major change to this program and another that targets energy service
11 suppliers ("ESSs"). Specifically, it proposes to extend the period over which it collects
12 transition charges (or credits) from customers from five years to ten.^{27/} It also proposes that
13 ESSs be decertified with the Commission to operate in Oregon if they fail to schedule with a
14 certain degree of accuracy.^{28/} While my testimony focuses primarily on the transition period, I
15 would note here that PGE has failed to provide any evidence that an ESSs' failure to schedule
16 accurately, even if it does occur, impacts its ability to reliably serve its load or harms its
17 customers in any way. Like anyone, ESSs are subject to imbalance charges if they inaccurately
18 schedule to ensure PGE is made whole.

^{27/} PGE/1300 at 40.

^{28/} Id.

1 **b. Transition Period**

2 **Q. WHAT IS THE BASIS FOR PGE’S PROPOSAL TO CALCULATE TRANSITION**
3 **CHARGES OVER TEN YEARS?**

4 A. The sole basis for this change appears to be PGE’s desire to align its program with that of
5 PacifiCorp’s, which includes ten years’ worth of transition payments over a five-year period.^{29/}

6 PGE does present a one-page exhibit (PGE/1308) that purports to show the impact of a
7 departing direct access customer on its system over a ten-year period, but this can hardly be
8 said to provide evidence that a ten-year transition period is reasonable. This exhibit fails to
9 account for load growth that offsets load lost from a departing customer; fails to consider the
10 value PGE receives from freed-up energy and freed-up capacity as a consequence of the
11 departing customer; and fails to provide any support for a finding that ten years’ worth of
12 transition charges is any more or less reasonable than any other number of years. In fact, one
13 could simply extend the period PGE’s exhibit covers out forever and it would be just as valid
14 as the ten-year view it has chosen to provide.

15 **Q. IS PGE RIGHT TO RELY ON PACIFICORP FOR A TEN-YEAR TRANSITION**
16 **CHARGE?**

17 A. No. PacifiCorp is a multi-state utility and its circumstances are unique from PGE’s. One of
18 the reasons why the Commission adopted a ten-year transition period for PacifiCorp had to do
19 with the multi-state protocol (“MSP”), which governs cost allocations between five of
20 PacifiCorp’s regulatory jurisdictions, including Oregon. Under Section X of the 2010
21 Protocol, direct access loads were required to be included when allocating costs to Oregon.
22 Thus, much of the cost-shifting at issue in PacifiCorp’s case was unavoidable due to the
23 structure of the MSP agreement that was in effect at the time. The same is not true for PGE.

^{29/} Id.

1 **Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE TRANSITION PERIOD?**

2 A. Absent a compelling reason to change the transition period, the status quo should be
3 maintained as it has proven to be the only workable and successful direct access program the
4 Commission has adopted. As noted above, while PGE seems to imply that its current long-
5 term opt-out program with five years of transition charges results in undue cost-shifting to non-
6 participating customers, it has failed to produce any credible evidence to support this claim.
7 The Commission should not fix what is not broken without an evidentiary basis demonstrating
8 harm from this program, particularly considering the clear benefits this program provides to
9 participating customers and to the state.

10 **c. Program Cap**

11 **Q. WHAT DOES PGE PROPOSE WITH RESPECT TO A CAP ON DIRECT ACCESS**
12 **PARTICIPATION?**

13 A. The current program contains a 300 aMW cap on the amount of load that may participate in the
14 permanent direct access program. PGE's filing does not address this cap, indicating that it
15 proposes no change to it. With approximately 240 aMW of capacity enrolled in the program,
16 however, only about 60 aMW of additional load is eligible to participate.

17 **Q. HAS THE CAP BEEN PROBLEMATIC FOR SCHEDULE 90 CUSTOMERS?**

18 A. Yes. Based on the way that the cap was designed, customers on Schedule 90 have been
19 ineligible to participate in the direct access program because the customers' load exceeds the
20 total remaining cap level.

21 **Q. WHAT DO YOU PROPOSE?**

22 A. I propose eliminating the cap altogether. As the new load direct access program the
23 Commission is currently considering in AR 614 demonstrates, a cap can be useful to ensure
24 that unanticipated impacts do not occur from a new and untested program. PGE's long-term

1 opt-out program, however, is not new and untested – it has been in place for nearly 16 years.
2 In that time, no party has ever offered evidence demonstrating negative impacts from this
3 program, either to participating customers, non-participating customers, or state policies the
4 Commission is charged with promoting. Indeed, as noted above, this program furthers such
5 policies by helping to implement a competitive market and driving additional renewables
6 development.

7 **Q. DO YOU EXPECT THAT LARGE NUMBERS OF CUSTOMERS WILL LEAVE FOR**
8 **DIRECT ACCESS WITHOUT A CAP IN PLACE?**

9 A. There is no reason to believe so. The same 300 aMW cap has been in place since the inception
10 of PGE's permanent direct access program and it has not been reached yet. Eliminating the
11 cap will simply provide all large non-residential customers with equal access to this program.

12 **d. Cost of Freed-up Capacity**

13 **Q. HOW DOES PGE CALCULATE THE TRANSITION ADJUSTMENT PAYMENTS**
14 **CURRENTLY?**

15 A. PGE uses a market-minus approach to calculate transition adjustments. Using this approach
16 the transition adjustment payments are calculated based on the difference between the total
17 amount of embedded production costs allocable to the departing customer, less the value of the
18 energy freed-up by the departing customer. The value of the freed-up energy is assumed to
19 equal the market prices input into PGE's MONET model. Under PGE's current approach, the
20 non-power cost portion of the transition adjustment is updated on a year-to-year basis through
21 the transition period, while the value of the freed-up energy is held static.

1 **Q. DO DEPARTING DIRECT ACCESS CUSTOMERS PROVIDE BENEFITS BEYOND**
2 **THE VALUE OF FREED-UP ENERGY?**

3 A. Yes. In addition to freeing up energy, which can be sold into the market, or used to serve other
4 customers, departing customers free up capacity and enable the utility to avoid constructing
5 new generation resources.

6 **Q. DOSE PGE'S CALCULATION CONSIDER THE VALUE OF FREED-UP**
7 **CAPACITY?**

8 A. No.

9 **Q. DO OTHER UTILITIES CONSIDER THE VALUE OF FREED-UP CAPACITY**
10 **WHEN CALCULATING TRANSITION ADJUSTMENTS?**

11 A. Yes. In the case of Microsoft's decision to permanently opt-out of the cost of service rates for
12 Puget Sound Energy ("Puget"), freed-up capacity costs were considered in the transition
13 adjustment calculation.^{30/} In fact, in all years after the fourth year of the analysis used to
14 calculate the impact of Microsoft's departure, that departure provided a net benefit to
15 remaining customers as a result of this freed-up capacity. The reason was because, after this
16 fourth year, Puget was projected to be in a capacity-short position due to the retirement of
17 Colstrip Units 1 and 2.

18 **Q. WILL A CREDIT FOR FREED-UP CAPACITY SEND AN APPROPRIATE PRICE**
19 **SIGNAL TO DEPARTING CUSTOMERS?**

20 A. Yes. Similar to the justification for the marginal generation cost study, which is designed to
21 provide a long-term price signal associated with the energy and capacity that customers
22 acquire, it is appropriate to include the value of freed-up capacity in the calculation of the
23 transition adjustment. If generation costs were allocated between demand and energy based on
24 short-term fixed and variable costs—as done in the market minus calculation—much fewer

^{30/} WUTC Docket UE-161123, Exh. JAP-1T at 4:1-6:13 (Oct. 7, 2016).

1 costs would be allocated to high load factor rate classes. The marginal cost study, however,
2 focuses on the long-term cost of demand and energy, recognizing that many costs which are
3 fixed in the short term can be considered variable when viewed in the long term.

4 **Q. HOW SHOULD THE VALUE OF FREED-UP CAPACITY BE CALCULATED?**

5 A. The value of freed up capacity should be calculated based on the marginal cost of capacity
6 assumed in PGE's generation marginal cost study. In PGE's initial filing, the marginal cost of
7 capacity was \$106.42/kW-yr, which should be applied as a credit, based on the demand of the
8 departing customer, in the transition adjustment calculation.

9 **Q. HOW SHOULD PGE IDENTIFY WHEN CUSTOMERS RECEIVE A CREDIT FOR**
10 **FREED-UP CAPACITY?**

11 A. I recommend that PGE modify Schedule 129 to include a demarcation similar to its resource
12 sufficiency/deficiency date in Schedule 201 for qualifying facilities. This demarcation would
13 identify the date on which the Company is anticipated to be capacity short, which would be
14 based on its most recent Integrated Resource Plan ("IRP"). Also like Schedule 201, PGE
15 would be able to update its capacity short demarcation date immediately following
16 acknowledgement of its most recent IRP. Customers who elect PGE's long-term opt-out
17 program within five years of the demarcation date would receive capacity credits in the years
18 that PGE is capacity short. Notably, this method also ensures that PGE will include direct
19 access as a capacity resource in its long-term planning, thereby reducing costs for all customers
20 (and potentially providing incremental environmental benefits) as future capacity additions are
21 avoided.

VII. OTHER RATE CASE ISSUES

a. Major Storm Balancing Account

Q. WHAT HAS PGE PROPOSED WITH RESPECT TO LEVEL III STORM COSTS.

A. As described at PGE/800 beginning on Page 13, PGE discusses its proposal to convert the level III storm accrual into a balancing account.

Q. DO YOU AGREE WITH PGE'S PROPOSAL?

A. No. PGE has not established the need for a balancing account. I recommend that the current method for Level III storm costs be retained.

Q. WHAT IS THE CURRENT RATEMAKING MECHANISM USED FOR LEVEL III STORMS?

A. The current mechanism was established through Order 10-478 in Docket No. UE 215. That method provides PGE with recovery of Level III storm costs using a 10-year rolling average, adjusted for the time value of money. The use of this method has the effect of smoothing the utility's recovery for major storms over time, rather than subjecting ratepayers to rate increases in years with a large magnitude of storm costs.

Q. DOES THE CURRENT METHOD PROVIDE PGE WITH THE OPPORTUNITY TO RECOVER LEVEL III STORM COSTS?

A. Yes. The use of a 10-year rolling average is a long-term method of deferred accounting. If the utility incurs relatively high Level III storm costs in any particular year, it is provided with the opportunity to recover those costs through an increase in the rolling average. As time progresses, the year with relatively high Level III storm costs will remain in the average calculation and provide the utility with full recovery for the costs incurred in that year. Additionally, PGE receives the benefit of years in which its Level III storm costs are lower than the ten-year average.

1 **Q. IS IT APPROPRIATE TO INCLUDE A ROLLING ACCRUAL AND A BALANCING**
2 **ACCOUNT?**

3 A. No. If it was decided to change the methodology and begin using a balancing account, it
4 would not be appropriate to continue to use the 10-year rolling average to establish base rates.

5 **Q. DO YOU HAVE AN EXAMPLE TO DEMONSTRATE WHY IT IS NOT**
6 **APPROPRIATE TO USE BOTH METHODOLOGIES?**

7 A. In 2017, PGE incurred Level III storm costs of \$11,351,424. Using the rolling 10-year
8 method, PGE accrues \$2,600,000 per year. Thus, PGE would collect an additional \$8,751,424
9 through the balancing account. Notwithstanding, the accrual rate also increased by \$1,214,696
10 in 2018 to \$3,814,696. Thus, under PGE's approach, the balancing account would provide
11 PGE with the ability to collect the cost of the 2017 storms twice, once through the balancing
12 account and again through the 10-year average calculation. If a balancing account is to be
13 used, it is necessary to reset the initial collections to zero.

14 **Q. IS PGE COMPARABLE TO THE OTHER UTILITIES IT CITES AS HAVING**
15 **STORM TRACKERS?**

16 A. No. I have experience working on cases with Entergy Arkansas, and PGE's need for a storm
17 tracker is not the same as Entergy's. Entergy provides services in an area of the country that
18 has experienced major hurricanes and tornado outbreaks. The risks and costs involved with
19 Hurricane Katrina, for example, are not the same type of weather risk we experience in the
20 Northwest.

21 **Q. DO YOU AGREE WITH PGE'S CALCULATION OF THE 10-YEAR AVERAGE**
22 **LEVEL III STORM COSTS?**

23 A. I've noted one minor correction to the calculation. As noted in Exhibit PGE/801, PGE
24 escalates the Level III storm cost through the end of 2019 when calculating the average. I
25 recommend applying the inflation factor through the end of 2018 and eliminating the 2019

1 escalation. Removing the 2019 escalation results in a \$89,771 reduction to the accrual. Other
2 than this minor correction, I do not oppose PGE's calculation.

3 **b. Customer Touchpoints Deferral**

4 **Q. PLEASE SUMMARIZE THE DEFERRALS THAT PGE HAS REQUESTED WITH**
5 **RESPECT TO ITS O&M ON THE CUSTOMER TOUCHPOINTS PROJECT.**

6 A. In Exhibit PGE/900, Page 15, lines 3 through 10, PGE identifies incremental O&M expenses
7 associated with the Customer Touchpoints project between the "go-live" date and January 1,
8 2019, and requests that those costs be subject to deferral. Further, in its application filed in
9 Docket No. UM 1948 on May 11, 2018, PGE requested the ability to defer the incremental
10 capital and O&M costs associated with the Customer Touchpoints project between the go-live
11 date and January 1, 2019.

12 **Q. ARE THOSE AMOUNTS APPROPRIATELY DEFERRED?**

13 A. No. PGE recently concluded a rate case to establish rates for 2018, and its information
14 technology costs for 2018 were reviewed in that proceeding. In addition, it is questionable
15 whether it is permissible for the return on a capital expenditure to be subject to deferred
16 accounting. PGE is seeking to be relieved of any regulatory lag associated with this project,
17 which as AWEC and CUB's briefing in UM 1909 has shown, improperly alters the balance
18 inherent in ratemaking against customers, particularly with respect to depreciable capital assets
19 like the Touchpoints project.^{31/}

^{31/} Docket No. UM 1909, Joint Opening Brief of CUB, ICNU and NWIGU at 6-9 (Mar. 16, 2018).

1 **c. Renewable Adjustment Clause**

2 **Q. WHAT CHANGE DOES PGE PROPOSE TO MAKE TO SCHEDULE 122, ITS RAC?**

3 A. PGE proposes to add energy storage to the RAC. The RAC is an automatic adjustment clause
4 (“AAC”) authorized pursuant to ORS 469A.120(2) that allows for “timely recovery” of
5 prudently incurred costs to meet the RPS. Senate Bill (“SB”) 1547, passed in 2016, amended
6 this section to allow recovery of “associated energy storage” with renewable energy facilities
7 through the RAC.^{32/}

8 **Q. IS PGE’S PROPOSAL TO RECOVER ENERGY STORAGE COSTS THROUGH THE**
9 **RAC CONSISTENT WITH THE LANGUAGE IN SB 1547?**

10 A. While I am not a lawyer, I do not believe so. PGE’s proposed revisions to Schedule 122
11 simply add the words “energy storage” to the category of items recoverable under that AAC,
12 meaning that any energy storage project would be eligible for the RAC, regardless of whether
13 it was “associated” with a renewable energy project.

14 **Q. DOES PGE EXPLAIN ITS PROPOSAL TO RECOVER ALL ENERGY STORAGE**
15 **COSTS THROUGH THE RAC?**

16 A. Yes. PGE states that “[a]ny energy storage facility on the system controlled by PGE provides
17 integrating renewable energy resources as a primary system benefit.”^{33/} Thus, PGE’s position
18 appears to be that all energy storage is “associated” with renewable energy because it all helps
19 to integrate that renewable energy in some manner.

20 **Q. IS THIS A DEFENSIBLE POSITION?**

21 A. No. PGE’s apparent definition of the word “associated” in SB 1547 is far too overbroad. Its
22 response to AWEC Data Request 039 demonstrates this. In that request, PGE was asked

^{32/} SB 1547 § 11(2)(a).

^{33/} PGE/1300 at 33:12-14.

1 whether its various generating resources – Port Westward 1 and 2, Carty, Beaver, Coyote
2 Springs, and its hydro generation – also provide “integrating renewable energy resources as a
3 primary system benefit.” And PGE agreed that they do: “PGE considers load balancing to be a
4 primary system benefit of its resource portfolio as a whole, which includes the generating
5 facilities identified above.”^{34/} Thus, for PGE, every resource on its system is “associated” with
6 renewable energy, which is the same thing as saying that the word “associated” is superfluous
7 in the statute. I do not believe the Legislature intended this result.

8 **Q. WHAT DO YOU RECOMMEND?**

9 A. SB 1547 clearly allows for recovery of “associated energy storage” through the RAC. I
10 therefore recommend that PGE be allowed to revise Schedule 122 to include this exact phrase,
11 and not simply “energy storage” as it has proposed. What qualifies as “associated” energy
12 storage should be resolved at a later date – either when PGE seeks to include an energy storage
13 project in the RAC or in the Commission’s ongoing RPS rulemaking, AR 610 – where a better
14 record for decision-making can be developed.

15 **Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?**

16 A. Yes.

^{34/} Exhibit AWEC/205 at 10 (PGE Resp. to AWEC DR 039).

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
<hr/>)

EXHIBIT NO. AWEC/201

REVENUE REQUIREMENT CALCULATIONS

Portland General Electric Corporation

Electric Revenue Requirement Summary (\$000)

In Thousands

Line	Adj. No.	Description	Cumulative Results			Impact of Adjustments			
			Net Oper. Income	Rate Base	Rev. Req. Def. / (Suf.)	Pre-Tax Net Oper. Income	Net Oper. Income	Rate Base	Rev. Req. Def. / (Suf.)
1		PGE Initial Filing	294,550	4,856,160	85,812				
2	A1	Cost of Capital	294,550	4,856,160	85,015	-	-	-	(797)
<i>Tax Cuts And Jobs Act</i>									
3	A2	Composite Tax Rate Correction	295,334	4,856,160	83,768		784	-	(1,247)
4	A3	EDFIT Correction	296,439	4,856,160	82,204		1,105	-	(1,564)
5	A4	EDFIT Alternative Method	296,994	4,864,830	82,314		555	8,670	111
6	A5	Interim Period Deferral Amortization	330,834	4,864,830	34,403	46,255	33,840	-	(47,912)
<i>Capital Expenditures</i>									
7	A6	Rate Base Measurement Date	330,834	4,752,752	22,819	-	-	(112,078)	(11,584)
8	A7	Field Voice Communications / Spectrum	330,834	4,716,803	19,103	-	-	(35,949)	(3,715)
9	A8	Project Specific Adjustments	330,834	4,715,069	18,924	-	-	(1,733.90)	(179)
10	A9	Non-Discrete Capital Additions	330,834	4,688,743	16,203	-	-	(26,326)	(2,721)
<i>Accumulated Deferred Taxes</i>									
11	A10	PTC Carry Forwards	330,834	4,619,253	9,021	-	-	(69,490)	(7,182)
12	A11	Accrued Vacation	330,834	4,614,411	8,521	-	-	(4,842)	(500)
13	A12	Stock Incentive Plan	330,834	4,610,908	8,159	-	-	(3,502)	(362)
14	A13	Boardman Severance	330,834	4,608,134	7,872	-	-	(2,775)	(287)
15	A14	Injuries and Damages	330,834	4,605,695	7,620	-	-	(2,439)	(252)
<i>Other Revenue Requirement Issues</i>									
16	A15	Depreciation Reserve	330,834	4,585,895	5,573	-	-	(19,800)	(2,046)
17	A16	Trojan NDT Amortization	331,346	4,585,895	4,848	700	512	-	(725)
18	A17	Touchpoints R&D Tax Credit	333,693	4,585,895	1,526		2,347	-	(3,322)
19	A18	UE 283 Incentives Adjustment	334,058	4,585,895	1,008	500	366	-	(518)
20	A19	Dispatchable Generation Regulatory Asset	334,058	4,574,077	(214)	-	-	(11,818)	(1,221)
21	A20	Boardman Severance	334,058	4,568,788	(760)	-	-	(5,289)	(547)
22	A21	Level III Storm Escalation	334,124	4,568,788	(853)	90	66	-	(93)
<i>Impact of adjustments Sponsored by Dr. Helman</i>									
23	A22	Employee Costs	352,747	4,556,974	(28,440)	25,454	18,622	(11,814)	(27,587)
Total Adjustments:						<u>72,999</u>	<u>58,196</u>	<u>(299,186)</u>	<u>(114,252)</u>

**Portland General Electric Company
Blended Statutory Income Tax Rate
Tax Return Data Through 2016**

	Tax Rate	nt % (4-Year Average)	Apportioned Tax Rate
Federal Income Tax Rate	21.00%	100.0000%	21.0000%
<u>State/Local</u>			
Local			
Multnomah County Income Tax	1.45%	31.9268%	0.4629%
Portland City Income Tax	2.20%	0.7411%	0.0163%
Local Total	3.65%	32.6679%	0.4792%
Local Federal Offset			-0.1006%
Local Oregon Offset			-0.0345%
Local Offset			-0.1351%
Local net of federal and Oregon benefit			0.3441%
Oregon	7.60%	94.7394%	7.2002%
Oregon Offset			-1.5048%
Oregon net of federal benefit			5.6954%
Montana Income Tax	6.75%	2.7846%	0.1880%
Montana Offset			-0.0395%
Montana net of federal benefit			0.1485%
California Income Tax	8.84%	2.0006%	0.1769%
California Offset			-0.0371%
California net of federal benefit			0.1397%
Total State			5.9836%
Total State & Local			6.3277%
Blended Statutory Rate			27.3277%
Less Multnomah			-0.4629%
Composite Rate			26.8648%

State Tax Rate Calculation- Apportionment Factors					
	2013	2014	2015	2016	4-Year Average
Multnomah County	34.1897%	33.9376%	31.9390%	27.6407%	31.9268%
Portland	0.7128%	0.9737%	0.7882%	0.4897%	0.7411%
Oregon	95.3421%	94.3375%	94.6150%	94.6630%	94.7394%
Montana	3.0341%	2.8727%	2.6566%	2.5749%	2.7846%
California	1.4437%	1.9993%	1.9200%	2.6393%	2.0006%

Portland General Electric Corporation
EDFIT Calculation using Alternative Method

<u>Line</u>	<u>Description</u>	<u>Source</u>	<u>Value</u>
1	Property Related ADFIT	AWEC DR 10	754,070,950
2	Old Composite Tax Rate	Exhibit AWEC 202	39.81%
3	Book Tax Difference Amount	Line 1 / Line 2	1,894,409,624
4	New Composite Tax Rate	Page 2	26.84%
5	ADFIT After Remeasurement	Line 3 * Line 4	508,459,543
6	EDFIT Gain	Line 1 - Line 5	245,611,407
7	Composite Depreciation Rate	Depreciation Study	3.53%
8	EDFIT Amortization	Line 6 * Line 7	8,670,083
9	PGE EDFIT Amortization	AWEC DR 17	8,115,311
10	Delta (Post-Tax)	Line 8 - Line 9	554,772

Portland General Electric Company

Deferral Amortization for Excess Taxes Collected in Rates Over the Period January 1, 2018 through December 31, 2018
Dollars

Month	Beg Balance	Amortization	Interest Rate	Interest	Ending Balance
1/1/2019	83,066,256	(3,854,600)	0.75%	684,040	79,895,696
2/1/2019	79,895,696	(3,854,600)	0.75%	660,148	76,701,244
3/1/2019	76,701,244	(3,854,600)	0.75%	636,076	73,482,720
4/1/2019	73,482,720	(3,854,600)	0.75%	611,823	70,239,943
5/1/2019	70,239,943	(3,854,600)	0.75%	587,387	66,972,730
6/1/2019	66,972,730	(3,854,600)	0.75%	562,767	63,680,897
7/1/2019	63,680,897	(3,854,600)	0.75%	537,961	60,364,259
8/1/2019	60,364,259	(3,854,600)	0.75%	512,969	57,022,627
9/1/2019	57,022,627	(3,854,600)	0.75%	487,788	53,655,815
10/1/2019	53,655,815	(3,854,600)	0.75%	462,417	50,263,632
11/1/2019	50,263,632	(3,854,600)	0.75%	436,855	46,845,887
12/1/2019	46,845,887	(3,854,600)	0.75%	411,101	43,402,388
1/1/2020	43,402,388	(3,854,600)	0.75%	385,152	39,932,940
2/1/2020	39,932,940	(3,854,600)	0.75%	359,008	36,437,348
3/1/2020	36,437,348	(3,854,600)	0.75%	332,667	32,915,415
4/1/2020	32,915,415	(3,854,600)	0.75%	306,127	29,366,943
5/1/2020	29,366,943	(3,854,600)	0.75%	279,388	25,791,730
6/1/2020	25,791,730	(3,854,600)	0.75%	252,447	22,189,577
7/1/2020	22,189,577	(3,854,600)	0.75%	225,303	18,560,280
8/1/2020	18,560,280	(3,854,600)	0.75%	197,954	14,903,634
9/1/2020	14,903,634	(3,854,600)	0.75%	170,399	11,219,433
10/1/2020	11,219,433	(3,854,600)	0.75%	142,637	7,507,470
11/1/2020	7,507,470	(3,854,600)	0.75%	114,665	3,767,536
12/1/2020	3,767,536	(3,854,600)	0.75%	86,483	(581) <-Goal Seek to Zero
Annual Amortization (Pre-tax):		(46,255,200)			

Portland General Electric Company

*Deferral Amortization for Excess Taxes Collected in Rates Over the Period January 1, 2018 through December 31, 2018
Using the Alternative Simplified Credit Calculation*

<u>Line</u>	<u>Description</u>	<u>Source</u>	<u>Value</u>
1	Total Touchpoints Project Cost	AWEC DR 17	130,571,018
2	25% Internal Use Safe Harbor	Line 1 * 25%	32,642,755
3	Contract Labor QREs @65%	Line 2 * 65%	21,217,790
4	Historical Qualified Research Expenditures (QREs):		
5	2015	Note	-
6	2016		-
7	2017	\	-
8	3-year avg	(Σ Lines 5:7) / 3	-
9	50% of three year Avg	Line 8 * 50%	-
10	Excess QREs	Line 3 - Line 9	21,217,790
11	Apply Credit Rate of 14%	Line 10 * 14%	2,970,491
12	Credit After 280 C	Line 11 * (1-21%)	2,346,688

Note: For purposes of this analysis I have assumed no base period QREs, as I expect those amounts not to be material in the overall calculation

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
<hr/>)

EXHIBIT NO. AWEC/202

IMPACT OF TAX CUTS AND JOBS ACT ON FILING

2019 Results of Operations
Increase in Base Rates Needed for Reasonable Return
Dollars in (000s)

	PGE Initial Filing, without TCJA			PGE Initial Filing			
	Base Business 9.65%			Base Business 4.78%			
	2019 Results at 2018 Base Rates	Change for Reasonable Return	2019 Results After Change for Reasonable Return	2019 Results at 2018 Base Rates	Change for Reasonable Return	2019 Results After Change for Reasonable Return	Revenue Delta
	(1)	(2)	(3)	(1)	(2)	(3)	
Operating Revenues							
Sales to Consumers (Rev. Req.)	1,798,713	173,614	1,972,327	1,798,713	85,908	1,884,622	(87,705)
Sales for Resale	-	-	-	-	-	-	
Other Operating Revenues	25,327	-	25,327	25,327	-	25,327	
Total Operating Revenues	1,824,041	173,614	1,997,654	1,824,041	85,908	1,909,949	
Operation & Maintenance							
Net Variable Power Cost	375,309	-	375,309	375,309	-	375,309	
Operations O&M	317,758	-	317,758	317,758	-	317,758	
Support O&M	265,341	1,153	266,494	265,341	571	265,911	
Total Operation & Maintenance	958,407	1,153	959,561	958,407	571	958,978	
Depreciation & Amortization	372,496	-	372,496	372,496	-	372,496	
Other Taxes / Franchise Fee	136,361	4,406	140,766	136,361	2,180	138,541	
Income Taxes	102,140	67,294	169,435	62,226	22,571	84,797	
Total Oper. Expenses & Taxes	1,569,405	72,853	1,642,258	1,529,491	25,322	1,554,812	
Utility Operating Income	254,636	100,760	355,396	294,550	60,586	355,137	
Rate of Return	5.242%		7.312%	6.065%		7.312%	
Return on Equity	5.361%		9.500%	7.008%		9.500%	

* 2016 Rates per approved UE 294

Rate Base						
Plant in Service	10,221,818	-	10,221,818	10,221,818	-	10,221,818
Accumulated Depreciation	(4,761,822)	-	(4,761,822)	(4,761,822)	-	(4,761,822)
Accumulated Def. Income Taxes	(679,665)	-	(679,665)	(679,665)	-	(679,665)
Accumulated Def. Inv. Tax Credit	-	-	-	-	-	-
Net Utility Plant	4,780,331	-	4,780,331	4,780,331	-	4,780,331
Misc Deferred Debits	9,294	-	9,294	9,294	-	9,294
Operating Materials & Fuel	78,945	-	78,945	78,945	-	78,945
Misc. Deferred Credits	(74,554)	-	(74,554)	(74,554)	-	(74,554)
Working Cash	63,765	2,960	66,725	62,143	1,029	63,172
Total Rate Base	4,857,781	2,960	4,860,741	4,856,160	1,029	4,857,189
Income Tax Calculations						
Book Revenues	1,824,041	173,614	1,997,654	1,824,041	85,908	1,909,949
Book Expenses	1,467,265	5,559	1,472,823	1,467,265	2,751	1,470,015
Interest Rate Base @ Weighted Cost of Debt	124,435	76	124,511	124,394	26	124,420
Production Deduction	-	-	-	-	-	-
Permanent Sch M Differences	(22,619)	-	(22,619)	(22,619)	-	(22,619)
Temporary Sch M Differences	63,378	-	63,378	63,378	-	63,378
State Taxable Income	191,582	167,979	359,561	191,623	83,131	274,755
State Income Tax	14,917	13,080	27,997	14,921	6,473	21,394
Federal Taxable Income	176,664	154,899	331,564	176,703	76,658	253,361
Fed Income Tax	61,832	54,215	116,047	37,108	16,098	53,206
Deferred Taxes	25,390	-	25,390	17,208	-	17,208
Excess ADIT Reversal (ARAM)	-	-	-	(7,010)	-	(7,010)
Federal Tax Credits	-	-	-	-	-	-
Total Income Tax	102,140	67,294	169,435	62,226	22,571	84,797

General Rate Case - 2019 Test Year
Capital Structure / Revenue Sensitive Costs
(000s)

Capital Structure:	Amount	Share	Cost	Weighted
Common Equity	N/A	50.00%	9.500%	4.750%
Preferred	N/A	0.00%	0.00%	0.000%
Long-Term Debt	N/A	50.00%	5.123%	2.562%
Total	N/A	100.00%		7.312%

Revenue Sensitive Costs:	
Revenues	100.0000%
OPUC Fees	0.3211%
Franchise Fees	2.5376%
O&M Uncollectibles	0.3431%
State Taxable Income	96.7982%
State and Local Tax @ 7.7865%	7.5372%
Federal Taxable Inc.	89.2610%
Federal Tax @ 21.000%	31.241354949394500%
Total Income Taxes	38.7785%
Total Rev. Sensitive Costs	41.9803%
Utility Operating Income	58.0197%
Net To Gross Factor	1.723554

RSC Gross-Up Factor 1.0331

State and Local Income Tax:

	Appor	Rate	Weighted
Portland	0.76%	2.20%	0.015%
Montana	2.86%	6.75%	0.193%
California	2.06%	8.84%	0.182%
Oregon	97.32%	7.60%	7.396%
State and Local Tax Rate			7.786%

Less Local Benefit to Oregon:

Oregon Rate	7.6000%
Local Rate	-0.0167%
Oregon Benefit of Local Tax deduction	-0.0013%

Composite Tax Rate: **40.0612%**

Check:	Fed Tax	35.0000%
	State Tax	7.7865%
	Tax Shield	-2.7253%
	Composite	40.0612%

Income Tax Summary
(000s)

	UE 319 2018 Test Year	2019 Test Year
<u>Income Tax Expense</u>		
Book Revenues	1,840,038	1,997,654
Book Expenses (including Depreciation)	1,355,693	1,472,823
Interest Deduction	117,207	124,511
Book Taxable Income	367,138	400,320
Production Deduction	9,000	-
Permanent Sch. M	(24,268)	(22,619)
Temporary Sch. M	45,835	63,378
Taxable Income	336,571	359,561
Current State Taxes	26,202	27,997
State Tax Credits	-	-
Net State Income Tax	26,202	27,997
Federal Taxable Income	310,369	331,564
Current Federal Taxes	108,629	116,047
Federal Tax Credits	-	-
ITC Amortization	-	-
Deferred Taxes	18,301	25,390
Total Income Tax	153,133	169,435
Effective Tax Rate	41.71%	42.32%
Change in Taxes		16,302
<u>Analysis of Tax Change:</u>		
Effective Tax Rate Change		0.61%
Book Taxable Income (UE 294)		367,138
Decrease in Taxes Due to Lower Effective Rate		2,258
Change in Book Taxable Income (2019 vs UE 319)		33,182
2019 Effective Tax Rate		42.32%
Decrease in Taxes Due to Lower Book Taxable Income		14,044
Sum of Tax Impacts		16,302

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
<hr/>)

**EXHIBIT NO. AWEC/203
INTERIM PERIOD DEFERRAL**

**Portland General Electric Company
2018 Revenue Requirement - Base Business
(\$000)**

FINAL, WITH TAX CUTS AND JOBS ACT (EXCLUDES EDFIT)

							Rev Req		Percent
							Total Increase:	(54,931)	-3.08%
	At Current Rates	Nov. Load Forecast Delta	GRC Change for RROE	Proposed 2018	Non-NVPC Adjustments	NVPC Adjustments	Total Results		
	(1)	(2)	(3)	(4)	(5)	(6)	(7)		
1 Sales to Consumers	1,783,435	13,902	12,049	1,809,386	(48,747)	(18,233)	1,742,406		
2 Sales for Resale	-			-	-	-	-		
3 Other Revenues	25,841			25,841	1,000	-	26,841		
4 Total Operating Revenues	1,809,276		12,049	1,835,227	(47,747)	(18,233)	1,769,247		
5 Net Variable Power Costs	353,586			353,586	-	(17,587)	335,999		
6 Production O&M (excludes Trojan)	159,768			159,768	154	-	159,922		
7 Trojan O&M	84			84	-	-	84		
8 Transmission O&M	14,306			14,306	-	-	14,306		
9 Distribution O&M	120,162			120,162	4	-	120,165		
10 Customer & MBC O&M	75,298			75,298	(803)	-	74,495		
11 Uncollectibles Expense	6,599		96	6,695	(167)	(63)	5,978		
12 OPUC Fees	6,688		97	6,785	(157)	(59)	5,595		
13 A&G, Ins/Bene., & Gen. Plant	164,970			164,970	(11,805)	-	153,165		
14 Total Operating & Maintenance	901,459		193	901,652	(12,774)	(17,709)	869,708		
15 Depreciation	317,424			317,424	(15,760)	-	301,665		
16 Amortization	59,854			59,854	(1,399)	-	58,455		
17 Property Tax	60,743			60,743	-	-	60,743		
18 Payroll Tax	16,109			16,109	(31)	-	16,078		
19 Other Taxes	2,434			2,434	-	-	2,434		
20 Franchise Fees	45,397		661	46,057	(1,241)	(464)	44,352		
21 Utility Income Tax	81,702		6,734	88,436	(3,827)	(11)	84,787		
22 Total Operating Expenses & Taxes	1,485,122		7,588	1,492,710	(35,031)	(18,184)	1,438,223		
23 Utility Operating Income	324,154		18,363	342,517	(12,716)	(49)	331,024		
				342,517			331,024		

FINAL, WITH TAX CUTS AND JOBS ACT (EXCLUDES EDFIT)

				Rev Req		Percent	
				Total Increase:	(54,931)	-3.08%	
	At Current Rates	Nov. Load Forecast Delta	GRC Change for RROE	Proposed 2018	Non-NVPC Adjustments	NVPC Adjustments	Total Results
24 Average Rate Base							
25 Avg. Gross Plant	9,879,272			9,879,272	(62,746)	-	9,816,526
26 Avg. Accum. Deprec. / Amort	(4,735,925)			(4,735,925)	7,943	-	(4,727,981)
27 Avg. Accum. Def Tax	(634,410)			(634,410)	(27,861)	-	(662,272)
28 Avg. Accum. Def ITC	-			-	-	-	-
29 Avg. Net Utility Plant	4,508,938		-	4,508,938	(82,664)	-	4,426,274
30 Misc. Deferred Debits	20,863			20,863	(3,923)	-	16,940
31 Operating Materials & Fuel	80,737			80,737	-	-	80,737
32 Misc. Deferred Credits	(73,318)			(73,318)	-	-	(73,318)
33 Working Cash	53,882		275	54,157	(1,271)	(660)	52,180
34 Average Rate Base	4,591,101		275	4,591,377	(87,858)	(660)	4,502,813
35 Rate of Return	7.060%			7.460%		7.352%	7.352%
36 Implied Return on Equity	8.951%			9.750%		9.500%	9.500%
37 Effective Cost of Debt	5.170%		5.170%	5.170%	5.203%	5.203%	5.203%
38 Effective Cost of Preferred	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%		50.000%	50.000%	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.585%		2.585%	2.585%	2.602%	2.602%	2.602%
42 Weighted Cost of Preferred	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%		50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.392%		7.392%	7.392%	7.392%	7.392%	7.392%
45 Federal Tax Rate	21.000%		21.000%	21.000%	21.000%	21.000%	21.000%
46 Composite Tax Rate	26.840%		26.840%	26.840%	26.840%	26.840%	26.840%
47 Bad Debt Rate	0.370%		0.370%	0.370%	0.343%	0.343%	0.343%
48 Franchise Fee Rate	2.545%		2.545%	2.545%	2.545%	2.545%	2.545%
49 Working Cash Factor	3.628%		3.628%	3.628%	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.367		1.367	1.367	1.367	1.367	1.367
51 ROE Target	9.750%		9.750%	9.750%	9.500%	9.500%	9.500%
52 Grossed-Up COC	9.248%		9.248%	9.248%	9.094%	9.094%	9.094%
53 OPUC Fee Rate	0.3750%		0.375%	0.375%	0.321%	0.321%	0.321%

FINAL, WITH TAX CUTS AND JOBS ACT (EXCLUDES EDFIT)

							Rev Req	Percent
							Total Increase:	(54,931)
							-3.08%	
	At Current Rates	Nov. Load Forecast Delta	GRC Change for RROE	Proposed 2018	Non-NVPC Adjustments	NVPC Adjustments	Total Results	
Utility Income Taxes								
54 Book Revenues	1,809,276		25,951	1,835,227	(47,747)	(18,233)	1,769,247	
55 Book Expenses	1,403,420		854	1,404,274	(31,204)	(18,173)	1,353,436	
56 Interest Deduction	118,680		7	118,687	(2,286)	(17)	117,141	
57 Production Deduction	9,000			9,000	-		9,000	
58 Permanent Ms	(24,268)			(24,268)	-		(24,268)	
59 Deferred Ms	45,835			45,835	-		45,835	
60 Taxable Income	256,609		25,090	281,699	(14,258)	(43)	268,104	
61 Current State Tax	19,635		1,855	21,490	(1,054)	(3)	20,485	
62 State Tax Credits	-			-	-		-	
63 Net State Taxes	19,635		1,855	21,490	(1,054)	(3)	20,485	
64 Federal Taxable Income	236,974		23,235	260,209	(13,204)	(40)	247,619	
65 Current Federal Tax	49,765		4,879	54,644	(2,773)	(8)	52,000	
66 Federal Tax Credits	-			-	-		-	
67 ITC Amort	-		-	-	-		-	
68 Deferred Taxes	12,302		0	12,302	-	-	12,302	
69 Total Income Tax Expense	81,702		6,734	88,436	(3,827)	(11)	84,787	
70 Regulated Net Income	205,474			223,830			213,884	

FINAL, WITHOUT TAX CUTS AND JOBS ACT

	Rev Req	Percent
Total Increase:	15,860	0.89%

	At Current Rates	Nov. Load Forecast Delta	GRC Change for RROE	Proposed 2018	Non-NVPC Adjustments	NVPC Adjustments	Total Results	Revenue Delta
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1 Sales to Consumers	1,783,435	13,902	85,995	1,883,332	(51,893)	(18,242)	1,813,197	(70,791)
2 Sales for Resale	-			-	-	-	-	
3 Other Revenues	25,841			25,841	1,000	-	26,841	
4 Total Operating Revenues	1,809,276		85,995	1,909,173	(50,893)	(18,242)	1,840,038	
5 Net Variable Power Costs	353,586			353,586	-	(17,587)	335,999	
6 Production O&M (excludes Trojan)	159,768			159,768	154	-	159,922	
7 Trojan O&M	84			84	-	-	84	
8 Transmission O&M	14,306			14,306	-	-	14,306	
9 Distribution O&M	120,162			120,162	4	-	120,165	
10 Customer & MBC O&M	75,298			75,298	(803)	-	74,495	
11 Uncollectibles Expense	6,599		370	6,968	(178)	(63)	6,221	
12 OPUC Fees	6,688		375	7,062	(167)	(59)	5,822	
13 A&G, Ins/Bene., & Gen. Plant	164,970			164,970	(11,820)	-	153,150	
14 Total Operating & Maintenance	901,459		744	902,203	(12,810)	(17,709)	870,163	
15 Depreciation	317,424			317,424	(15,760)	-	301,665	
16 Amortization	59,854			59,854	(1,399)	-	58,455	
17 Property Tax	60,743			60,743	-	-	60,743	
18 Payroll Tax	16,109			16,109	(31)	-	16,078	
19 Other Taxes	2,434			2,434	-	-	2,434	
20 Franchise Fees	45,397		2,543	47,939	(1,321)	(464)	46,154	
21 Utility Income Tax	121,190		38,559	159,749	(6,901)	(21)	153,133	
22 Total Operating Expenses & Taxes	1,524,610		41,846	1,566,457	(38,221)	(18,194)	1,508,826	
23 Utility Operating Income	284,665		58,051	342,716	(12,672)	(49)	331,212	
				342,716			331,212	

FINAL, WITHOUT TAX CUTS AND JOBS ACT

							Rev Req		Percent
							Total Increase:	15,860	0.89%
	At Current Rates	Nov. Load Forecast Delta	GRC Change for RROE	Proposed 2018	Non-NVPC Adjustments	NVPC Adjustments	Total Results	Revenue Delta	
24 Average Rate Base									
25 Avg. Gross Plant	9,879,272			9,879,272	(62,746)	-	9,816,526		
26 Avg. Accum. Deprec. / Amort	(4,735,925)			(4,735,925)	7,943	-	(4,727,981)		
27 Avg. Accum. Def Tax	(634,410)			(634,410)	(27,861)	-	(662,272)		
28 Avg. Accum. Def ITC	-			-	-	-	-		
29 Avg. Net Utility Plant	4,508,938		-	4,508,938	(82,664)	-	4,426,274		
30 Misc. Deferred Debits	20,863			20,863	(3,923)	-	16,940		
31 Operating Materials & Fuel	80,737			80,737	-	-	80,737		
32 Misc. Deferred Credits	(73,318)			(73,318)	-	-	(73,318)		
33 Working Cash	55,314		1,518	56,833	(1,387)	(660)	54,742		
34 Average Rate Base	4,592,534		1,518	4,594,052	(87,974)	(660)	4,505,374		
35 Rate of Return	6.198%			7.460%		7.351%	7.351%		
36 Implied Return on Equity	7.227%			9.750%		9.500%	9.500%		
37 Effective Cost of Debt	5.170%		5.170%	5.170%	5.203%	5.203%	5.203%		
38 Effective Cost of Preferred	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%		
39 Debt Share of Cap Structure	50.000%		50.000%	50.000%	50.000%	50.000%	50.000%		
40 Preferred Share of Cap Structure	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%		
41 Weighted Cost of Debt	2.585%		2.585%	2.585%	2.602%	2.602%	2.602%		
42 Weighted Cost of Preferred	0.000%		0.000%	0.000%	0.000%	0.000%	0.000%		
43 Equity Share of Cap Structure	50.000%		50.000%	50.000%	50.000%	50.000%	50.000%		
44 State Tax Rate	7.582%		7.582%	7.582%	7.582%	7.582%	7.582%		
45 Federal Tax Rate	35.000%		35.000%	35.000%	35.000%	35.000%	35.000%		
46 Composite Tax Rate	39.928%		39.928%	39.928%	39.928%	39.928%	39.928%		
47 Bad Debt Rate	0.370%		0.370%	0.370%	0.343%	0.343%	0.343%		
48 Franchise Fee Rate	2.545%		2.545%	2.545%	2.545%	2.545%	2.545%		
49 Working Cash Factor	3.628%		3.628%	3.628%	3.628%	3.628%	3.628%		
50 Gross-Up Factor	1.665		1.665	1.665	1.665	1.665	1.665		
51 ROE Target	9.750%		9.750%	9.750%	9.500%	9.500%	9.500%		
52 Grossed-Up COC	10.700%		10.700%	10.700%	10.509%	10.509%	10.509%		
53 OPUC Fee Rate	0.3750%		0.375%	0.375%	0.321%	0.321%	0.321%		

FINAL, WITHOUT TAX CUTS AND JOBS ACT

	Rev Req	Percent
Total Increase:	15,860	0.89%

	At Current Rates	Nov. Load Forecast Delta	GRC Change for RROE	Proposed 2018	Non-NVPC Adjustments	NVPC Adjustments	Total Results	Revenue Delta
Utility Income Taxes								
54 Book Revenues	1,809,276		99,897	1,909,173	(50,893)	(18,242)	1,840,038	
55 Book Expenses	1,403,420		3,287	1,406,707	(31,320)	(18,173)	1,355,693	
56 Interest Deduction	118,717		39	118,756	(2,289)	(17)	117,207	
57 Production Deduction	9,000			9,000	-		9,000	
58 Permanent Ms	(24,268)			(24,268)	-		(24,268)	
59 Deferred Ms	45,835			45,835	-		45,835	
60 Taxable Income	256,572		96,571	353,143	(17,284)	(52)	336,571	
61 Current State Tax	20,136		7,322	27,459	(1,311)	(4)	26,202	
62 State Tax Credits	-			-	-		-	
63 Net State Taxes	20,136		7,322	27,459	(1,311)	(4)	26,202	
64 Federal Taxable Income	236,436		89,249	325,684	(15,974)	(48)	310,369	
65 Current Federal Tax	82,752		31,237	113,989	(5,591)	(17)	108,629	
66 Federal Tax Credits	-			-	-		-	
67 ITC Amort	-		-	-	-		-	
68 Deferred Taxes	18,301		0	18,301	-	-	18,301	
69 Total Income Tax Expense	121,190		38,559	159,749	(6,901)	(21)	153,133	
70 Regulated Net Income	165,948			223,960			214,005	

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
<hr/>)

EXHIBIT NO. AWEC/204

NOTICE OF INTERNAL USE SOFTWARE REGULATIONS

Dated: September 28, 2016.

Harriet Tregoning,
*Principal Deputy Assistant, Secretary for
 Community Planning and Development.*

[FR Doc. 2016-23986 Filed 10-3-16; 8:45 am]

BILLING CODE 4210-67-P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[TD 9786]

RIN 1545-BC70

Credit for Increasing Research Activities

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Final regulations.

SUMMARY: This document contains final regulations concerning the application of the credit for increasing research activities. These final regulations provide guidance on software that is developed by (or for the benefit of) the taxpayer primarily for internal use by the taxpayer (internal use software). These final regulations also include examples to illustrate the application of the process of experimentation requirement to software. These final regulations will affect taxpayers engaged in research activities involving software.

DATES: *Effective date:* These regulations are effective on October 4, 2016.

Applicability date: For date of applicability see § 1.41-4(e).

FOR FURTHER INFORMATION CONTACT:

Martha Garcia or Jennifer Records of the IRS Office of the Associate Chief Counsel (Passthroughs and Special Industries) at (202) 317-6853 (not a toll-free number).

SUPPLEMENTARY INFORMATION:

Background

This document contains final regulations that amend the Income Tax Regulations (26 CFR part 1) relating to the credit for increasing research activities (research credit) under section 41 of the Internal Revenue Code (Code). Section 41(d)(4)(E) provides that, except to the extent provided by regulations, research with respect to software that is developed by (or for the benefit of) the taxpayer primarily for internal use by the taxpayer is excluded from the definition of qualified research under section 41(d). Software that is developed for use in an activity that constitutes qualified research for purposes of section 41(d) and software

that is developed for use in a production process with respect to which the general credit eligibility requirements under section 41 are satisfied are internal use software, but are not excluded under section 41(d)(4)(E) from the definition of qualified research and are not subject to these regulations.

On January 20, 2015, the Treasury Department and the IRS published in the *Federal Register* (80 FR 2624, January 20, 2015) a notice of proposed rulemaking (REG-153656-03, 2015-5 IRB 566) under section 41 (the proposed regulations) relating to the research credit. Comments responding to the proposed regulations were received and a public hearing was held on April 17, 2015. After consideration of all of the comments received, these final regulations adopt the proposed regulations as revised by this Treasury decision.

Summary of Comments and Explanation of Provisions

I. Definition of Internal Use Software

The proposed regulations provided that software is developed by (or for the benefit of) the taxpayer primarily for internal use if the software is developed by the taxpayer for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business. General and administrative functions, as defined in the proposed regulations, are limited to (1) financial management functions, (2) human resource management functions, and (3) support services functions. Financial management functions are functions that involve the financial management of the taxpayer and the supporting recordkeeping. Human resource management functions are functions that manage the taxpayer's workforce. Support services functions are functions that support the day-to-day operations of the taxpayer, such as data processing or facilities services.

Commenters expressed concern that the list of general and administrative functions in the proposed regulations was overly broad and included functions that do not represent "back-office" functions. In particular, the commenters noted that inventory management, marketing, legal services, and government compliance services can provide significant benefits to third parties and may be developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system. Specifically, one commenter noted that many inventory management software applications are an integral part of a taxpayer's supply

chain management system and can be readily seen as part of the modern "front office." This commenter noted that modern inventory management software usually requires interaction with a number of third party vendors to ensure the correct flow of raw materials and a corresponding flow of finished goods. Additionally, the commenter added that inventory management is inherently customer facing because it provides the proper amount of inventory to customers at the point of sale at the right time. Another commenter added that marketing is an external-facing function by nature, and software that supports marketing is necessarily intended to interact with third parties.

The Treasury Department and the IRS understand that many modern software systems perform more than back-office functions. These software systems commonly provide benefits to vendors and include functions that are customer facing. Additionally, software with functions such as marketing or inventory management may not provide solely back-office functions, but may also contain functions that enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system. Recognizing such situations, the proposed regulations provided rules under § 1.41-4(c)(6)(iv)(C) (dual function rules) to evaluate whether software that has both back-office and front-office functions is developed primarily for internal use. The Treasury Department and the IRS continue to believe that functions such as inventory management, marketing, legal services, and government compliance services provide support to day-to-day operations of a taxpayer in carrying on business regardless of the taxpayer's industry and that the benefits that such functions may provide to third parties are collateral and secondary. In addition, the Treasury Department and the IRS believe the dual function rules in these final regulations sufficiently address these comments by allowing taxpayers to identify subsets of elements of dual function software that only enable a taxpayer to interact with third parties or allow third parties to initiate functions or review data. Accordingly, the list of general and administrative functions provided in the proposed regulations remains unchanged in the final regulations.

Another commenter referred to the tax software example in the preamble to the proposed regulations which notes that tax software developed by a company engaged in providing tax services to its customers is not used by the taxpayer in general and administrative functions

even though tax is listed under § 1.41–4(c)(6)(iii)(B)(1) of the proposed regulations, as a general and administrative function. The commenter requested that we make this concept more explicit by revising § 1.41–4(c)(6)(iii)(A) of the proposed regulations and providing additional examples. As discussed in the preamble to the proposed regulations, the list of general and administrative functions is intended to target the back-office functions that most taxpayers would have regardless of the taxpayer's industry, although the characterization of a function as back office will vary depending on the facts and circumstances of the taxpayer. Because § 1.41–4(c)(6)(v) of these final regulations makes clear that the determination of whether software is developed primarily for internal use depends on the intent of the taxpayer and the facts and circumstances at the beginning of software development, the Treasury Department and the IRS believe that additional clarifying language and examples are unnecessary.

II. Definition of Software Not Developed Primarily for Internal Use

The proposed regulations provided that software is not developed primarily for internal use only if it is developed to be commercially sold, leased, licensed, or otherwise marketed to third parties, or if it is developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system. After consideration of the comments described herein, these final regulations clarify that (1) software is not developed primarily for the taxpayer's internal use if it is not developed for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business; and (2) software that is developed to be commercially sold, leased, licensed, or otherwise marketed to third parties and software that is developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system are examples of software that is not developed primarily for the taxpayer's internal use.

A. Software Developed To Be Commercially Sold, Leased, Licensed or Otherwise Marketed to Third Parties

A commenter requested that § 1.41–4(c)(6)(iv)(A)(1) of the proposed regulations be revised to state that software is not developed primarily for the taxpayer's internal use if the software is developed to be

commercially sold, leased, licensed, hosted, or otherwise marketed to third parties. (Emphasis added.) The commenter also recommended additional language to further define “otherwise marketed” to include transactions where the taxpayer effectively provides the functionality of the software to a third party even if there is no transfer of a copy of the software itself to such third party. The Treasury Department and the IRS understand that a taxpayer may develop software where the full functionality of that software is provided to a third party even though there is no transfer of a copy of the software. The Treasury Department and the IRS believe the phrase “software that is developed to be commercially sold, leased, licensed or otherwise marketed to third parties” is sufficiently broad to encompass hosted software and other software where there is no transfer of a copy of the software. An example has been added to further illustrate this point (Example 9 of these final regulations).

B. Software Developed To Enable a Taxpayer To Interact With Third Parties or Allow Third Parties To Initiate Functions or Review Data on the Taxpayer's System

Several commenters requested clarification on the terms “interact,” “initiate,” or “review,” and recommended additional examples illustrating the terms. One commenter noted that a common example that should be clarified is whether a third party reviewing a Web site constitutes “interaction,” “initiate functions,” or “review data.” In response to these comments, the final regulations clarify that software that is developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system are examples of software that is not developed primarily for the taxpayer's internal use. In addition, these final regulations provide that the determination of whether software is internal use or developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system depends on the intent of the taxpayer and the facts and circumstances at the beginning of the software development. Accordingly, Example 3 of the proposed regulations, now designated as Example 4 in these final regulations, is revised to show that software developed with the intent of marketing via a Web site and not to allow third parties to review data on the taxpayer's system is developed for internal use because it was developed

for use in a general and administrative function.

III. Connectivity Software

In the proposed regulations, the Treasury Department and the IRS requested comments on the appropriate definition and treatment of connectivity software that allows multiple processes running on one or more machines to interact across a network, sometimes referred to as bridging software, integration software, or middleware. The Treasury Department and the IRS received very few responses to this request for comments. One of the commenters noted that the treatment of such software is challenging because of its multi-faceted purposes; it could fall within a category in which it is not sold, does not interact with a third party, and does not perform a general and administrative function. The other commenter recommended that the regulations provide a general rule for connectivity software that is tied to the intent of the taxpayer and the facts and circumstances at the beginning of the software development and that the regulations provide examples demonstrating the rule. In addition, with respect to this category of software, the Treasury Department and the IRS understand that with wide use and availability of enterprise resource planning (ERP) software, few companies actually engage in developing connectivity software. Connectivity software is often purchased or the need for it has diminished due to the use of ERP software.

After further consideration of business practices and the limited comments received, the Treasury Department and the IRS believe that a special rule for connectivity software is not needed. The final regulations clarify that software is not developed by (or for the benefit of) the taxpayer primarily for the taxpayer's internal use if the software is not developed for use in general and administrative functions. Accordingly, any software that is not developed to be used in a general and administrative function will not be considered to be developed for internal use. This is the case even if the software is not developed to be commercially sold, leased, licensed, or otherwise marketed to third parties, or is not developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system.

Furthermore, connectivity software should not be specifically identified or categorized differently from other types of software. Whether certain software is developed to be used primarily for

internal use should be based on the function the software provides, rather than the type of software. For example, connectivity software that is developed to connect a taxpayer's existing payroll software with financial budgeting software to allow an exchange of data between the two software modules would be considered to be developed for the taxpayer's internal use because the connectivity software's function is to be used in human resources and financial management functions. Accordingly, the Treasury Department and the IRS believe that the general rule in the final regulations to determine whether or not software is developed primarily for internal use already provides sufficient guidance for connectivity software. Whether software, including connectivity software, is developed for use in general and administrative functions depends upon the intent of the taxpayer and the facts and circumstances at the beginning of the software development.

IV. Intent of the Taxpayer and the Facts and Circumstances at the Beginning of the Software Development

The proposed regulations provided that whether software is or is not developed primarily for internal use depends upon the intent of the taxpayer and the facts and circumstances at the beginning of the software development. If a taxpayer originally develops software primarily for internal use but later makes improvements to the software with the intent to hold the improved software for commercial sale, lease, or license or to allow third parties to initiate functions or review data on the taxpayer's system, the improvements will be considered separate from the existing software and will not be considered developed primarily for internal use. Likewise, if a taxpayer originally develops software for commercial sale, lease, or license or to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system, but later makes improvements to the software with the intent to use the software in general and administrative functions, the improvements will be considered separate from the existing software and will be considered developed primarily for internal use. After consideration of the comments described below, these final regulations retain these rules without modification.

A commenter explained that it is common for a taxpayer to initiate a software development project with one purpose in mind and to later discover that other purposes should be considered and pursued. Commenters

also explained that it is common for a taxpayer to abandon its original intentions of how the software might be used. Commenters made several different recommendations, among them that the final regulations adopt a standard that allows facts at any point during the software development to be considered. Another suggested looking to the intended use of the software, and not just the improvements, as of the tax return filing date for the taxable year or the beginning of the taxable year in which the software development expenditures were incurred. One commenter further suggested that if the regulations require a determination at the beginning of the software development, the regulations should allow that determination to be rebutted with evidence about how the software is actually used when it is placed in service. Commenters also noted that taxpayers will likely have difficulty substantiating their intended use of the software at the beginning of the development process.

The Treasury Department and the IRS conclude that only a rule that generally requires that a determination be made at the beginning of software development is consistent with the intent and the purpose of section 41. Congress intended that the credit for increasing research activities would provide an incentive for greater private activity in research. That incentive nature of section 41 is promoted by taking into account a taxpayer's intent at the beginning of the software development; allowing any change in a taxpayer's intent throughout the development to support treatment as qualifying research of expenses incurred prior to that change would frustrate the purpose of the credit. Furthermore, allowing a taxpayer to redetermine the overall project's credit eligibility throughout the development which could span multiple years would provide uncertain and inconsistent treatment and impose an undue burden on both taxpayers and the IRS. Finally, the final regulations continue to provide a special rule for improvements to software that can be separately identified. This special rule would apply, for example, when a taxpayer completes a software development and then decides to improve that software by undertaking further development to the same software.

V. Dual Function Software and Safe Harbor

A. Presumption and Third Party Subset

The proposed regulations provided that software developed by (or for the

benefit of) the taxpayer both for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business and to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data (dual function software) is presumed to be developed primarily for a taxpayer's internal use. However, this presumption is inapplicable to the extent that a taxpayer can identify a subset of elements of dual function software that only enables a taxpayer to interact with third parties or allows third parties to initiate functions or review data on the taxpayer's system (third party subset). The proposed regulations provided that if the taxpayer can identify a third party subset, the portion of qualified research expenditures allocable to such third party subset of the dual function software may be eligible for the research credit, provided all the other applicable requirements are met.

The Treasury Department and the IRS received several comments on dual function software rules. One commenter recommended changes to clarify that the dual function software rules do not apply to software developed to be commercially sold, leased, licensed, or otherwise marketed to third parties, even if such software was also developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system.

The Treasury Department and the IRS believe such clarification is unnecessary as § 1.41-4(c)(6)(iv)(C)(1) of the proposed regulations clearly defines dual function software as software that is developed by the taxpayer both for use in general and administrative functions and to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data. Software that is developed to be commercially sold, leased, licensed, or otherwise marketed to third parties is not dual function software, even if such software was also developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system.

One commenter suggested that the "substantially all" and "shrink back" rules found in § 1.41-4(b)(2) can be easily applied to evaluate dual function software. If substantially all of the software is non-internal use, then all of the software should be considered non-internal use under the substantially all rule. Similarly, if substantially all of the software is internal use, then the software should be considered internal use. In the case where the software as

a whole does not meet the substantially all rule, then the taxpayer would apply the shrink back rule and the software would be divided into subcomponents based on functionality until the non-internal use portion and the internal use portion were appropriately separated. That commenter noted that these two rules have worked for many years with little difficulty in other areas of the research credit rules and could be used equally well to address the issue of dual function software. Another commenter encouraged the addition of a rule to cover cases in which a taxpayer's dual function subset's third party use or interaction exceeds 80 percent. The commenter stated that in this circumstance, the remaining internal use is de minimis and should be disregarded and the entire development should be treated as not developed for internal use.

The shrink back rule provides that the requirements of section 41(d) and § 1.41-4(a) are to be applied first at the level of the discrete business component, that is, the product, process, computer software, technique, formula, or invention to be held for sale, lease, or license, or used by the taxpayer in a trade or business of the taxpayer. If these requirements are not met at that level, then they apply at the most significant subset of elements of the product, process, computer software, technique, formula, or invention to be held for sale, lease, or license. This shrinking back of the product is to continue until either a subset of elements of the product that satisfies the requirements is reached, or the most basic element of the product is reached and such element fails to satisfy the test.

The Treasury Department and the IRS believe that the proposed rules already apply principles similar to the shrink back rule to allow taxpayers to identify a subset of elements of dual function software that only enables a taxpayer to interact with third parties or allows third parties to initiate functions or review data on the taxpayer's system. The substantially all test referenced by the commenter is similar to the general credit eligibility requirement in section 41(d)(1)(C), which provides that in order for activities to constitute qualified research, substantially all of the activities must constitute elements of a process of experimentation that relates to a qualified purpose. Under § 1.41-4(a)(6), this substantially all requirement is satisfied only if 80 percent or more of a taxpayer's research activities, for the development or improvement of a business component, measured on a cost or other consistently applied reasonable basis, constitute

elements of a process of experimentation. In contrast to the general requirement of section 41(d)(1) pertaining to qualifying research, section 41(d)(4)(E) does not apply the substantially all test when it excludes activities related to internal use software from qualifying research. Accordingly, the Treasury Department and the IRS believe the use of the substantially all test in these regulations is inappropriate, and the final regulations do not adopt the commenter's suggested approach.

Another commenter requested that the dual function rules be eliminated because the provisions are confusing and unnecessary and that trying to delineate elements of dual function software raises significant administrative issues. Similarly, another commenter noted that the concepts in the dual function rules can be confusing to taxpayers and will require additional recordkeeping by taxpayers. According to this commenter, most taxpayers do not differentiate their software applications by "third party interactions" or generally track such interactions. One commenter similarly stated that § 1.41-4(c)(6)(iv)(C) of the proposed regulations fails to take into account that software systems cannot always be broken into mutually exclusive subsets enabling only internal use or third party functionality.

Regarding the presumption that dual function software is developed for internal use, a commenter stated that such presumption is contrary to the intent of the statute. One commenter recommended that the presumption should be replaced with a primary purpose test, consistent with the statutory language that looks to whether software is developed "primarily" for internal use.

The Treasury Department and the IRS believe it is necessary to implement rules for dual function software as this type of software development is increasingly common in business practice. Rather than simply reiterating the "primarily" language in the statute, these regulations specifically identify the types of software functions that are considered to be primarily for internal use. A definition that specifically identifies the types of software functions that are considered to be primarily for internal use provides a clearer objective test that will provide consistency in application. The nature of software and its development has rapidly evolved over time, and the statute did not expressly address the treatment of dual function software. In conjunction with crafting a narrow definition of internal use, the Treasury

Department and the IRS believe that the dual function software rules in the proposed regulations strike an appropriate balance between the administrative burdens and compliance concerns relating to claiming the research credit for activities relating to software. Thus, these final regulations retain the dual function rules. These final regulations are applicable to taxable years beginning on or after the date of their publication in the **Federal Register**. Taxpayers have been aware of the proposed rules and have had the opportunity to begin maintaining the necessary documentation to establish their entitlement to research credits under these rules.

B. Safe Harbor

The proposed regulations provided taxpayers with a safe harbor to apply to dual function software if there remains a subset of elements of dual function software (dual function subset) after the third party subset has been identified. The safe harbor allows a taxpayer to include 25 percent of the qualified research expenditures of the dual function subset in computing the amount of the taxpayer's credit, provided that the taxpayer's research activities related to the dual function subset constitute qualified research and the use of the dual function subset by third parties or by the taxpayer to interact with third parties is reasonably anticipated to constitute at least 10 percent of the dual function subset's use.

Some commenters requested that the safe harbor be removed from the regulations. Specifically, one commenter stated that the burdens associated with the safe harbor may be greater than its benefits and noted the multiple steps that a taxpayer must take to determine if it meets the safe harbor. Another commenter noted that the safe harbor complicates the administration of the credit for both taxpayers and the IRS.

Another commenter noted that the safe harbor potentially penalizes the taxpayer with the inequitable result of allowing only 25 percent of the qualified research expenditures. According to the commenter, given that a taxpayer must document anticipated use, it should then follow that the portion of software treated as third party facing should mirror this analysis. In other words, the proportion anticipated to be third party facing should be the proportion of software that is not developed primarily for internal use.

After careful consideration, the final regulations do not adopt these comments. However, the safe harbor has

been modified to clarify that the safe harbor can be applied to the dual function software or the dual function subset after the application of § 1.41-4(c)(6)(vi)(B) of the final regulations. The safe harbor is not a requirement but an option available for taxpayers who cannot identify a third party subset, or after identification of a third party subset, still have a dual function subset. Without the safe harbor, dual function software or a dual function subset would be presumed to be internal use and the taxpayer would have to demonstrate that the research with respect to the dual function software or dual function subset meets the high threshold of innovation test in addition to the general eligibility requirements under section 41(d)(1). The safe harbor provides a benefit, not a detriment, to taxpayers, provided the dual function software or dual function subset's use by third parties is anticipated to be at least 10 percent of the total use. Taxpayers who consider it too burdensome to comply with the requirements of the safe harbor can choose not to rely upon it.

C. Time of Determination

Several commenters noted concerns with the time of determination for the application of the safe harbor. A commenter noted that determining the percentage of third party use based upon an estimate made at the beginning of software development imposes an undue administrative burden and may not be an accurate reflection of the actual use once the software is released. This commenter requested that the rule be eliminated or amended to provide that a taxpayer must estimate third party use once the software is deployed. Similarly, another commenter noted that it has not been their experience that taxpayers plot out the future expected use of their software at the time the development begins with such specificity, especially given that software development is an iterative development process where functionality and expected uses rapidly evolve. Lastly, another commenter requested that, similar to the provisions for improvements to existing software, there should be a mechanism to recharacterize software over time.

While the Treasury Department and the IRS understand commenters' concerns, the final regulations do not change the requirement that the time of determination occur at the beginning of the software development. As discussed herein, the Treasury Department and the IRS continue to believe that the rule requiring that a determination be made at the beginning of the software

development is most accurate and appropriate given Congress' intent that the research credit serve as an incentive to conduct qualifying research rather than an unanticipated reward for doing so.

D. Objective Reasonable Method

In the proposed regulations, the Treasury Department and the IRS invited comments on the administrability of measuring the reasonably anticipated use of software by taxpayers to interact with third parties and by third parties to initiate functions or review data based on reasonable methods (such as processing time, amount of data transfer, number of software user interface screens, number of third party initiated functions, and other objective, reasonable methods) and whether the regulations should include specific reasonable methods and examples.

A commenter recommended that due to the wide range of taxpayers that will be subject to these regulations, the final regulations should not provide overly detailed examples of "reasonable methods." This commenter noted that it should be clear that any examples of reasonable methods are for illustrative purposes only and any reasonable method may be acceptable. Another commenter recommended the adoption of the phrase "within each industry" to ensure that the application of the objective, reasonable method takes into account unique aspects of all taxpayers within given industries.

The Treasury Department and the IRS agree that it is unrealistic to impose one specific method that will be used to measure reasonably anticipated use due to the variety of industries that are subject to the final regulations. Therefore, the final regulations provide that any objective, reasonable method within the taxpayer's industry may be used for purposes of the safe harbor.

VI. Third Party Definition

The proposed regulations provided that the term "third party" means any corporation, trade or business, or other person that is not treated as a single taxpayer with the taxpayer pursuant to section 41(f). A commenter raised concerns and requested that the Treasury Department and the IRS reconsider whether it is appropriate to apply the controlled group standard under section 41(f). The commenter contended that this third party definition would potentially deny a research credit to some software for artificial reasons. The commenter further noted that if the regulations do not modify the third party definition,

taxpayers should at least have an opportunity to demonstrate that software provided to a member of the controlled group is not internal use software based on the facts and circumstances.

The Treasury Department and the IRS continue to believe that the use of the controlled group standard under section 41(f) is appropriate. A well established, objective standard is essential and using the standard in section 41(f) is consistent with the reference to section 41(f) in section 41(b)(2) relating to in-house research expenditures and in § 1.41-6(a)(3)(ii) relating to the definition of controlled group for purposes of aggregating expenditures.

The proposed regulations also provided that third parties do not include any persons that use the software to support the taxpayer's general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business, e.g., the taxpayer's own vendors. A commenter contended that excluding any person that uses a taxpayer's software to support a general and administrative function from the definition of third party creates confusion and blurs a well-conceived, objective measurement. This commenter believes the term third party suggests a person who is external to the organization or a person who is not an employee. The Treasury Department and the IRS note that the statute provides a higher standard for internal use software, in part, because the benefits of such software are intended primarily for the taxpayer developing it. Where a taxpayer develops software for internal use, any benefit to others, such as vendors or those who provide support services to the taxpayer, is collateral and secondary. Accordingly, the final regulations do not adopt these comments requesting a change to the definition of third party.

VII. High Threshold of Innovation—Significant Economic Risk

The proposed regulations provided that certain internal use software is eligible for the research credit if the software satisfies the high threshold of innovation test, the three parts of which are (1) software is innovative in that the software would result in a reduction in cost or improvement in speed or other measurable improvement, that is substantial and economically significant, if the development is or would have been successful; (2) software development involves significant economic risk in that the taxpayer commits substantial resources to the development and there is a substantial uncertainty, because of

technical risk, that such resources would be recovered within a reasonable period; and (3) software is not commercially available for use by the taxpayer in that the software cannot be purchased, leased, or licensed and used for the intended purpose without modifications that would satisfy the innovation and significant economic risk requirements. The proposed regulations further provided that substantial uncertainty exists if, at the beginning of the taxpayer's activities, the information available to the taxpayer does not establish the capability or method for developing or improving the software.

A. Design Uncertainty

Several commenters requested that the final regulations include design uncertainty in the definition of technical risk for purposes of meeting the significant economic risk test. Commenters noted that both sections 174 and 41 have long included the concept of design uncertainty. Commenters also raised concerns that the statute and regulations do not define the concepts of capability, methodology, and design uncertainty. Commenters further explained that these three types of uncertainties are inherently related to each other, and it is often difficult for taxpayers to clearly state or describe which type of uncertainty they face.

The use of the word "substantial" before "uncertainty" in the significant economic risk test for internal use software indicates a higher threshold of uncertainty than that required for business components that are not internal use software. While there may be design uncertainty in the development of internal use software, substantial uncertainty generally exists only when there is also uncertainty in regard to the capability or method of achieving the intended result. However, the Treasury Department and the IRS understand that it is difficult to delineate the types of technical uncertainties and attempting to do so may lead to unnecessary burdens on both taxpayers and the IRS.

Furthermore, the appropriate design uncertainty of internal use software may be inextricably linked to substantial uncertainty regarding capability or method. The focus of the significant economic risk test should be on the level of uncertainty that exists and not the types of uncertainty. For these reasons, the final regulations remove the reference to capability and method uncertainty. However, the Treasury Department and the IRS believe that internal use software research activities that involve only uncertainty related to

appropriate design, and not capability or methodology, would rarely qualify as having substantial uncertainty for purposes of the high threshold of innovation test.

B. Substantial Resources/Reasonable Time Period

A commenter requested that the final regulations provide further explanation or examples on what constitutes "substantial resources" or a "reasonable time period" for purposes of meeting the significant economic risk test. The Treasury Department and the IRS believe that whether the amount of resources committed is substantial or whether substantial resources would be recovered within a reasonable time period are factual determinations to be resolved based on the taxpayer's facts and circumstances and, therefore, further explanation or examples would be too specific and not helpful. Accordingly, the final regulations do not adopt these comments.

C. Application of High Threshold of Innovation Test

Another commenter requested deletion of the statement, "[i]t is not always necessary to have a revolutionary discovery or creation of new technologies such as a new programming language, operating system, architecture, or algorithm to satisfy the high threshold of innovation test." The commenter is concerned that the sentence can be read to imply that in some situations it will be necessary to have a revolutionary discovery to qualify internal use software for the research credit. The Treasury Department and the IRS did not intend the inclusion of this statement to have the interpretation suggested or taken by the commenter. Accordingly, the Treasury Department and the IRS agree that this statement should be removed from the final regulations because a revolutionary discovery is not required to meet the high threshold of innovation test.

Furthermore, the Treasury Department and the IRS are revising §§ 1.41–4(c)(6)(i) and (ii) of the proposed regulations to clarify that the internal use software rules under § 1.41–4(c)(6) do not apply to (1) software developed for use in an activity that constitutes qualified research, (2) software developed for use in a production process to which the requirements of section 41(d)(1) are met, and (3) a new or improved package of software and hardware developed together by the taxpayer as a single product. Accordingly, under the final regulations, the high threshold of

innovation test applies only to the software developed for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business and to dual function software.

VIII. Examples

A. Process of Experimentation

Section 1.41–4(a)(8) of the proposed regulations provided six new examples illustrating the application of the process of experimentation requirement to software under section 41(d)(1)(C).

One commenter noted that the examples appear to suggest a presumption that activities related to developing web design or ERP software do not meet the process of experimentation requirement. This commenter requested that the final regulations clearly state the reasons for such presumption. The proposed regulations and these final regulations do not establish a presumption against a particular type of software; rather these examples focus on the facts and circumstances surrounding activities to determine whether they involve a process of experimentation.

Another commenter requested that the final regulations include additional examples demonstrating fact patterns that do not initially qualify as a process of experimentation but where a change in facts introduces technical uncertainty that requires a process of experimentation. The final regulations could provide examples describing a particular change in facts that would introduce technical uncertainty and require a process of experimentation; however, because the examples are very factual and would differ based on a taxpayer's business, we do not think more examples would provide the clarification that the commenter is seeking. Accordingly, the final regulations do not include additional examples to address this comment.

i. Example 6

Section 1.41–4(a)(8), Example 6, of the proposed regulations analyzed whether activities related to selecting a commercial software vendor with object-oriented functions and selecting and incorporating the specific functions into new software developed by X involved conducting a process of experimentation.

One commenter noted that the use of certain terms in Example 6, such as "develop," "evaluate," and "determine" suggest that the process of experimentation criteria may be met and recommended changes to clearly show that a purchase, installation, and

selection from pre-determined categories do not meet a process of experimentation. We disagree with the commenter because the use or nonuse of certain terms is not an implication that the process of experimentation criteria has or has not been met. This example is intended to show that the process of experimentation requirement is not met regardless of the terms used. Accordingly, the final regulations do not adopt this comment.

ii. Example 7

Section 1.41–4(a)(8), Example 7, of the proposed regulations analyzed whether when developing software, activities relating to X's decision to use a separate server to distribute the workload across each of the web servers and X's decision that a round robin workload distribution algorithm is appropriate for its needs involved conducting a process of experimentation.

Two commenters recommended removing Example 7. One commenter believed that the example did not provide any clarification. The other commenter stated that the example shows a failure to meet the technical uncertainty requirement under section 174, rather than a process of experimentation. While the Treasury Department and the IRS agree with the commenter that activities under section 174 must be for the purpose of discovering information that would eliminate uncertainties, Example 7 is intended to demonstrate the process of experimentation requirement under section 41(d). The example shows a taxpayer's failure to meet the process of experimentation requirement under section 41(d)(1) because the use of a technique or design, such as a round robin workload distribution algorithm, does not qualify where the taxpayer did not conduct a process of evaluating alternatives intended to eliminate uncertainty regarding the development of software. Accordingly, the final regulations do not adopt these comments.

iii. Example 8

Section 1.41–4(a)(8), Example 8, of the proposed regulations analyzed whether X's activities relating to design and systematic testing and evaluation of several different algorithms in the development of load balancing software involved conducting a process of experimentation.

One commenter recommended that all references to the terms "dynamic" and "highly volatile" be removed because the commenter believes the terms provide no additional value and that

they suggest that the nature of X's business environment has some bearing on the performance of qualified research. The Treasury Department and the IRS disagree and the final regulations do not adopt the commenter's recommendation because we believe the nature of a taxpayer's business environment can be a valuable indicator of circumstances that may result in the necessary uncertainty required for a process of experimentation.

Another commenter requested that for both Example 8 and Example 10, the Treasury Department and the IRS provide clarification by applying the high threshold of innovation test once the software is determined to be internal use software. Additionally, this commenter requested that the final regulations provide an additional example addressing this process. The Treasury Department and the IRS note that the examples are added to illustrate only the application of a process of experimentation to software research. They are not meant to address the high threshold of innovation test; those examples were provided under § 1.41–4(c)(6)(vi) of the proposed regulations. Furthermore, a comprehensive example that applies the rules contained in § 1.41–4(c)(6) would require more developed facts and layers of analysis and would be better suited for a different type of published guidance than these final regulations. Accordingly, the final regulations do not adopt these comments.

iv. Example 9

Section 1.41–4(a)(8), Example 9, of the proposed regulations analyzed whether X's activities relating to the installation of an ERP system involved a process of experimentation.

Two commenters requested deletion of the phrase "routine programming" in Example 9 because the term is subjective, immeasurable, and inconsistent with *Suder v. Commissioner*, T.C. Memo 2014–201. One commenter also stated that taxpayers may confront uncertainty about the appropriate design of the configuration of an ERP system, and the example does not address this technical uncertainty. The Treasury Department and the IRS did not intend to illustrate in this example the types of uncertainty that must be eliminated to satisfy the process of experimentation requirement under section 41(d)(1). Rather, this example demonstrates a taxpayer's failure to meet the process of experimentation requirement under section 41(d)(1) because X did not conduct a process of evaluating

alternatives in order to eliminate uncertainty regarding the development of the ERP software. Accordingly, the Treasury Department and the IRS believe further clarification of these examples is unnecessary. Furthermore, the Tax Court's decision in *Suder* is not inconsistent with Example 9 because in *Suder* the court did not address whether "routine programming" could meet the process of experimentation requirement.

B. Internal Use Software

The proposed regulations provided examples illustrating the provisions contained in § 1.41–4(c)(6) of the proposed regulations.

i. Example 3

Section 1.41–4(c)(6)(vi), Example 3, of the proposed regulations analyzed whether software that is developed for a Web site that provides general information about the taxpayer's business, and which does not enable a taxpayer to interact with third parties or allow third parties to initiate functions or review data, is internal use software.

One commenter disagreed with the characterization of the facts in Example 3 which illustrates a support services function. The commenter believes that the software is dual function software that is developed to allow a third party to review data and to be used in marketing. The Treasury Department and the IRS disagree with the commenter's characterization of Example 3. The example demonstrates that the software is intended to serve marketing purposes and thus is developed to be used in general and administrative functions. Changes were made to clarify this example which is designated as Example 4 of the final regulations.

ii. Example 6

Section 1.41–4(c)(6)(vi), Example 6, of the proposed regulations analyzed the definition of third parties, specifically whether software that is developed to allow its users to upload and modify photographs at no charge allows third parties to initiate functions on the taxpayer's system.

A commenter believed the example is an important example that comes to the correct conclusion, but the commenter believed it is not a particularly good fact pattern to illustrate the third party interaction exclusion. Specifically, the commenter requested changes to the conclusion of the example to show that the advertising software is developed for use in a marketing function to an unrelated third party.

The purpose of the example is to illustrate the third party definition and

to demonstrate whether the software is developed to allow third parties to initiate functions or review data. The example is not meant to address which, if any, general and administrative function applies to the software. Accordingly, the final regulations do not adopt this comment. However, other changes were made to clarify Example 6 of the proposed regulations, which is designated as Example 8 of the final regulations.

IX. Effective/Applicability Date

Some commenters requested that the final regulations apply retroactively back to 1986, while one commenter requested that the final regulations apply retroactively back to 2004 to give software development equal treatment with all other types of qualified research as defined under TD 9104 (69 FR 22). After further consideration, the effective date in the proposed regulations is generally retained with slight modifications. These final regulations are prospective and apply to taxable years beginning on or after the date of publication of this Treasury decision in the **Federal Register**.

Retroactive application of these final regulations may provide an unfair advantage to taxpayers whose prior taxable years are not closed by the statute of limitations. Furthermore, retroactively determining whether taxpayers engaged in research activities does not further the purpose of section 41 which is to encourage taxpayers to engage in qualifying research activities within the United States and would impose a significant administrative burden on the IRS.

Section 41(d)(4)(E) provides that, except to the extent provided by regulations, research with respect to computer software that is developed by (or for the benefit of) the taxpayer primarily for internal use by the taxpayer is excluded from the definition of qualified research under section 41(d). The nature of software and its development has rapidly evolved over time. Recognizing the evolving nature of software technology and its role in business practices, these final regulations more narrowly define internal use software than the rules that apply for prior periods. These final regulations are not, and should not be viewed as, an interpretation of prior regulatory guidance. Software not developed for internal use under these final regulations, such as software developed to enable a taxpayer to interact with third parties, may or may not have been internal use software under prior law.

The proposed regulations provided that the 2004 ANPRM (published in the **Federal Register** (69 FR 43)) is withdrawn effective for taxable years beginning on or after January 20, 2015, the date the proposed regulations were published in the **Federal Register** (80 FR 2624). For taxable years ending before January 20, 2015, taxpayers may choose to follow either all of the internal use software provisions of § 1.41-4(c)(6) in the final regulations published on January 3, 2001 in the **Federal Register** (TD 8930; 66 FR 280) or all of the internal use software provisions of § 1.41-4(c)(6) contained in the proposed regulations (REG-112991-01) published on December 26, 2001 in the **Federal Register** (66 FR 66362). In addition, the IRS will not challenge return positions consistent with all of paragraph (c)(6) of these final regulations or all of paragraph (c)(6) of the proposed regulations for any taxable year that both ends on or after January 20, 2015, the date the proposed regulations were published in the **Federal Register** (80 FR 2624), and begins before October 4, 2016.

X. Duty of Consistency

Some commenters noted the administrative difficulties of applying the duty of consistency rule under section 41(c)(6)(A) and requested guidance on how to comply with the consistency rule.

The duty of consistency is a statutory requirement and existing regulations under §§ 1.41-3(d) and 1.41-9(c) provide sufficient guidance for taxpayers to follow. In computing the research credit, qualified research expenses and gross receipts must be determined on a basis consistent with the definition of qualified research expenses and gross receipts for the credit year. These final regulations do not modify this existing law. Section 1.41-3(d) provides that in computing the credit for increasing research activities, qualified research expenses and gross receipts taken into account in computing a taxpayer's fixed-base percentage and a taxpayer's base amount must be determined on a basis consistent with the definition of qualified research expenses and gross receipts for the credit year, without regard to the law in effect for the taxable years taken into account in computing the fixed-base percentage or the base amount. Section 1.41-3(d) also provides examples illustrating the requirement. Current section 1.41-9(c) contains similar rules. Accordingly, the final regulations do not adopt the commenters' suggestions concerning the duty of consistency.

Special Analyses

Certain IRS regulations, including this one, are exempt from the requirements of Executive Order 12866, as supplemented and reaffirmed by Executive Order 13563. Therefore, a regulatory impact assessment is not required. It also has been determined that section 553(b) of the Administrative Procedure Act (5 U.S.C. chapter 5) does not apply to these regulations, and because the regulations do not impose a collection of information on small entities, the Regulatory Flexibility Act (5 U.S.C. chapter 6) does not apply. Pursuant to section 7805(f) of the Code, the notice of proposed rulemaking was submitted to the Chief Counsel for Advocacy of the Small Business Administration for comment on its impact on small business, and no comments were received.

Drafting Information

The principal author of these regulations is Martha M. Garcia, Office of the Associate Chief Counsel (Passthroughs and Special Industries), IRS. However, other personnel from the Treasury Department and the IRS participated in their development.

List of Subjects in 26 CFR Part 1

Income taxes, Reporting and recordkeeping requirements.

Adoption of Amendments to the Regulations

Accordingly, 26 CFR part 1 is amended as follows:

PART 1—INCOME TAXES

■ **Paragraph 1.** The authority citation for part 1 is amended by adding an entry in numerical order to read in part as follows:

Authority: 26 U.S.C. 7805 * * *

* * * * *
Section 1.41-4 also issued under 26 U.S.C. 41(d)(4)(E).

* * * * *

■ **Par. 2.** Section 1.41-0 is amended by:

■ 1. Revising the entry in the table of contents for § 1.41-4(c)(6).

■ 2. Adding entries in the table of contents for § 1.41-4(c)(6)(i) through (viii).

The revision and additions read as follows:

§ 1.41-0. Table of contents.

* * * * *

§ 1.41-4. Qualified research for expenditures paid or incurred in taxable years ending on or after December 31, 2003.

* * * * *

(c) * * *

- (6) Internal use software.
- (i) General rule.
- (ii) Inapplicability of the high threshold of innovation test.
- (iii) Software developed primarily for internal use.
- (iv) Software not developed primarily for internal use.
- (v) Time and manner of determination.
- (vi) Software developed for both internal use and to enable interaction with third parties (dual function software).
- (vii) High threshold of innovation test.
- (viii) Illustrations.

* * * * *

■ Par. 3. Section 1.41–4 is amended by:

■ 1. Adding *Example 5* through *Example 10* at the end of paragraph (a)(8).

■ 2. Revising paragraphs (c)(6) and (e).
The additions and revisions read as follows:

§ 1.41–4 Qualified research for expenditures paid or incurred in taxable years ending on or after December 31, 2003.

(a) * * *

(8) * * *

Example 5. (i) *Facts.* X, a retail and distribution company, wants to upgrade its warehouse management software. X evaluates several of the alternative warehouse management software products available from vendors in the marketplace to determine which product will best serve X's technical requirements. X selects vendor V's software.

(ii) *Conclusion.* X's activities to select the software are not qualified research under section 41(d)(1) and paragraph (a)(5) of this section. X did not conduct a process of evaluating alternatives in order to eliminate uncertainty regarding the development of a business component. X's evaluation of products available from vendors is not a process of experimentation.

Example 6. (i) *Facts.* X wants to develop a new web application to allow customers to purchase its products online. X, after reviewing commercial software offered by various vendors, purchases a commercial software package of object-oriented functions from vendor Z that X can use in its web application (for example, a shopping cart). X evaluates the various object-oriented functions included in vendor Z's software package to determine which functions it can use. X then incorporates the selected software functions in its new web application software.

(ii) *Conclusion.* X's activities related to selecting the commercial software vendor with the object-oriented functions it wanted, and then selecting which functions to use, are not qualified research under section 41(d)(1) and paragraph (a)(5) of this section. In addition, incorporating the selected object-oriented functions into the new web application software being developed by X did not involve conducting a process of evaluating alternatives in order to eliminate

uncertainty regarding the development of software. X's evaluation of products available from vendors and selection of software functions are not a process of experimentation.

Example 7. (i) *Facts.* In order to be more responsive to user online requests, X wants to develop software to balance the incoming processing requests across multiple web servers that run the same set of software applications. Without evaluating or testing any alternatives, X decides that a separate server will be used to distribute the workload across each of the web servers and that a round robin workload distribution algorithm is appropriate for its needs.

(ii) *Conclusion.* X's activities to develop the software are activities relating to the development of a separate business component under section 41(d)(2)(A). X's activities to develop the load distribution function are not qualified research under section 41(d)(1) and paragraph (a)(5) of this section. X did not conduct a process of evaluating different load distribution alternatives in order to eliminate uncertainty regarding the development of software. X's selection of a separate server and a round robin distribution algorithm is not a process of experimentation.

Example 8. (i) *Facts.* X must develop load balancing software across a server cluster supporting multiple web applications. X's web applications have high concurrency demands because of a dynamic, highly volatile environment. X is uncertain of the appropriate design of the load balancing algorithm, given that the existing evolutionary algorithms did not meet the demands of their highly volatile web environment. Therefore, X designs and systematically tests and evaluates several different algorithms that perform the load distribution functions.

(ii) *Conclusion.* X's activities to develop software are activities to develop a separate business component under section 41(d)(2)(A). X's activities involving the design, evaluation, and systematic testing of several new load balancing algorithms meet the requirements as set forth in paragraph (a)(5) of this section. X's activities constitute elements of a process of experimentation because X identified uncertainties related to the development of a business component, identified alternatives intended to eliminate those uncertainties, and evaluated one or more alternatives to achieve a result where the appropriate design was uncertain at the beginning of X's research activities.

Example 9. (i) *Facts.* X, a multinational manufacturer, wants to install an enterprise resource planning (ERP) system that runs off a single database so that X can track orders more easily, and coordinate manufacturing, inventory, and shipping among many different locations at the same time. In order to successfully install and implement ERP software, X evaluates its business needs and the technical requirements of the software, such as processing power, memory, storage, and network resources. X devotes the majority of its resources in implementing the ERP system to evaluating the available templates, reports, and other standard programs and choosing among these

alternatives in configuring the system to match its business process and reengineering its business process to match the available alternatives in the ERP system. X also performs some data transfer from its old system, involving routine programming and one-to-one mapping of data to be exchanged between each system.

(ii) *Conclusion.* X's activities related to the ERP software including the data transfer are not qualified research under section 41(d)(1) and paragraph (a)(5) of this section. X did not conduct a process of evaluating alternatives in order to eliminate uncertainty regarding the development of software. X's activities in choosing between available templates, reports, and other standard programs and conducting data transfer are not elements of a process of experimentation.

Example 10. (i) *Facts.* Same facts as *Example 9* except that X determines that it must interface part of its legacy software with the new ERP software because the ERP software does not provide a particular function that X requires for its business. As a result, X must develop an interface between its legacy software and the ERP software, and X evaluates several data exchange software applications and chooses one of the available alternatives. X is uncertain as to how to keep the data synchronized between the legacy and ERP systems. Thus, X engages in systematic trial and error testing of several newly designed data caching algorithms to eliminate synchronization problems.

(ii) *Conclusion.* Substantially all of X's activities with respect to this ERP project do not satisfy the requirements for a process of experimentation. However, when the shrinking-back rule is applied, a subset of X's activities do satisfy the requirements for a process of experimentation. X's activities to develop the data caching software and keeping the data on the legacy and ERP systems synchronized meet the requirements of qualified research as set forth in paragraph (a)(2) of this section. Substantially all of X's activities to develop the specialized data caching and synchronization software constitute elements of a process of experimentation because X identified uncertainties related to the development of a business component, identified alternatives intended to eliminate those uncertainties, and evaluated alternatives to achieve a result where the appropriate design of that result was uncertain as of the beginning of the taxpayer's research activities.

* * * * *

(c) * * *

(6) *Internal use software*—(i) *General rule.* Research with respect to software that is developed by (or for the benefit of) the taxpayer primarily for the taxpayer's internal use is eligible for the research credit only if—

(A) The research with respect to the software satisfies the requirements of section 41(d)(1);

(B) The research with respect to the software is not otherwise excluded under section 41(d)(4) (other than section 41(d)(4)(E)); and

(C) The software satisfies the high threshold of innovation test of paragraph (c)(6)(vii) of this section.

(ii) *Inapplicability of the high threshold of innovation test.* This paragraph (c)(6) does not apply to the following:

(A) Software developed by (or for the benefit of) the taxpayer primarily for internal use by the taxpayer for use in an activity that constitutes qualified research (other than the development of the internal use software itself);

(B) Software developed by (or for the benefit of) the taxpayer primarily for internal use by the taxpayer for use in a production process to which the requirements of section 41(d)(1) are met; and

(C) A new or improved package of software and hardware developed together by the taxpayer as a single product (or to the costs to modify an acquired software and hardware package), of which the software is an integral part, that is used directly by the taxpayer in providing services in its trade or business. In these cases, eligibility for the research credit is to be determined by examining the combined hardware-software product as a single product.

(iii) *Software developed primarily for internal use—(A) In general.* Except as otherwise provided in paragraph (c)(6)(vi) of this section, software is developed by (or for the benefit of) the taxpayer primarily for the taxpayer's internal use if the software is developed for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business. Software that the taxpayer develops primarily for a related party's internal use will be considered internal use software. A related party is any corporation, trade or business, or other person that is treated as a single taxpayer with the taxpayer pursuant to section 41(f).

(B) *General and administrative functions.* General and administrative functions are:

(1) *Financial management.* Financial management functions are functions that involve the financial management of the taxpayer and the supporting recordkeeping. Financial management functions include, but are not limited to, functions such as accounts payable, accounts receivable, inventory management, budgeting, cash management, cost accounting, disbursements, economic analysis and forecasting, financial reporting, finance, fixed asset accounting, general ledger bookkeeping, internal audit, management accounting, risk

management, strategic business planning, and tax.

(2) *Human resources management.* Human resources management functions are functions that manage the taxpayer's workforce. Human resources management functions include, but are not limited to, functions such as recruiting, hiring, training, assigning personnel, and maintaining personnel records, payroll, and benefits.

(3) *Support services.* Support services are other functions that support the day-to-day operations of the taxpayer. Support services include, but are not limited to, functions such as data processing, facility services (for example, grounds keeping, housekeeping, janitorial, and logistics), graphic services, marketing, legal services, government compliance services, printing and publication services, and security services (for example, video surveillance and physical asset protection from fire and theft).

(iv) *Software not developed primarily for internal use.* Software is not developed primarily for the taxpayer's internal use if it is not developed for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business, such as—

(A) Software developed to be commercially sold, leased, licensed, or otherwise marketed to third parties; or

(B) Software developed to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system.

(v) *Time and manner of determination.* For purposes of paragraphs (c)(6)(iii) and (iv) of this section, whether software is developed primarily for internal use or not developed primarily for internal use depends on the intent of the taxpayer and the facts and circumstances at the beginning of the software development. For example, software will not be considered internal use software solely because it is used internally for purposes of testing prior to commercial sale, lease, or license. If a taxpayer originally develops software primarily for internal use, but later makes improvements to the software with the intent to hold the improved software to be sold, leased, licensed, or otherwise marketed to third parties, or to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system using the improved software, the improvements will be considered separate from the existing software and will not be considered developed primarily for

internal use. Alternatively, if a taxpayer originally develops software to be sold, leased, licensed, or otherwise marketed to third parties, or to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system, but later makes improvements to the software with the intent to use the software in general and administrative functions, the improvements will be considered separate from the existing software and will be considered developed primarily for internal use.

(vi) *Software developed for both internal use and to enable interaction with third parties (dual function software)—(A) Presumption of development primarily for internal use.* Unless paragraph (c)(6)(vi)(B) or (C) of this section applies, software developed by (or for the benefit of) the taxpayer both for use in general and administrative functions that facilitate or support the conduct of the taxpayer's trade or business and to enable a taxpayer to interact with third parties or to allow third parties to initiate functions or review data on the taxpayer's system (dual function software) is presumed to be developed primarily for a taxpayer's internal use.

(B) *Identification of a subset of elements of software that only enables interaction with third parties.* To the extent that a taxpayer can identify a subset of elements of dual function software that only enables a taxpayer to interact with third parties or allows third parties to initiate functions or review data (third party subset), the presumption under paragraph (c)(6)(vi)(A) of this section does not apply to such third party subset, and such third party subset is not developed primarily for internal use as described under paragraph (c)(6)(iv)(B) of this section.

(C) *Safe harbor for expenditures related to software developed for both internal use and to enable interaction with third parties.* If, after the application of paragraph (c)(6)(vi)(B) of this section, there remains dual function software or a subset of elements of dual function software (dual function subset), a taxpayer may include 25 percent of the qualified research expenditures of such dual function software or dual function subset in computing the amount of the taxpayer's credit. This paragraph (c)(6)(vi)(C) applies only if the taxpayer's research activities related to the development or improvement of the dual function software or dual function subset constitute qualified research under section 41(d), without regard to section 41(d)(4)(E), and the dual function software or dual function

subset's use by third parties or by the taxpayer to interact with third parties is reasonably anticipated to constitute at least 10 percent of the dual function software or the dual function subset's use. An objective, reasonable method within the taxpayer's industry must be used to estimate the dual function software or dual function subset's use by third parties or by the taxpayer to interact with third parties. An objective, reasonable method may include, but is not limited to, processing time, amount of data transfer, and number of software user interface screens.

(D) *Time and manner of determination.* A taxpayer must apply this paragraph (c)(6)(vi) based on the intent of the taxpayer and the facts and circumstances at the beginning of the software development.

(E) *Third party.* For purposes of paragraphs (c)(6)(iv), (v), and (vi) of this section, the term *third party* means any corporation, trade or business, or other person that is not treated as a single taxpayer with the taxpayer pursuant to section 41(f). Additionally, for purposes of paragraph (c)(6)(iv)(B) of this section, third parties do not include any persons that use the software to support the general and administrative functions of the taxpayer.

(vii) *High threshold of innovation test—(A) In general.* Software satisfies this paragraph (c)(6)(vii) only if the taxpayer can establish that—

- (1) The software is innovative;
- (2) The software development involves significant economic risk; and
- (3) The software is not commercially available for use by the taxpayer in that the software cannot be purchased, leased, or licensed and used for the intended purpose without modifications that would satisfy the requirements of paragraphs (c)(6)(vii)(A)(1) and (2) of this section.

(B) *Innovative.* Software is innovative if the software would result in a reduction in cost or improvement in speed or other measurable improvement, that is substantial and economically significant, if the development is or would have been successful. This is a measurable objective standard, not a determination of the unique or novel nature of the software or the software development process.

(C) *Significant economic risk.* The software development involves significant economic risk if the taxpayer commits substantial resources to the development and if there is substantial uncertainty, because of technical risk, that such resources would be recovered within a reasonable period. The term "substantial uncertainty" requires a

higher level of uncertainty and technical risk than that required for business components that are not internal use software. This standard does not require technical uncertainty regarding whether the final result can ever be achieved, but rather whether the final result can be achieved within a timeframe that will allow the substantial resources committed to the development to be recovered within a reasonable period. Technical risk arises from uncertainty that is technological in nature, as defined in paragraph (a)(4) of this section, and substantial uncertainty must exist at the beginning of the taxpayer's activities.

(D) *Application of high threshold of innovation test.* The high threshold of innovation test of paragraph (c)(6)(vii) of this section takes into account only the results anticipated to be attributable to the development of new or improved software at the beginning of the software development independent of the effect of any modifications to related hardware or other software. The implementation of existing technology by itself is not evidence of innovation, but the use of existing technology in new ways could be evidence of a high threshold of innovation if it resolves substantial uncertainty as defined in paragraph (c)(6)(vii)(C) of this section.

(viii) *Illustrations.* The following examples illustrate provisions contained in this paragraph (c)(6). No inference should be drawn from these examples concerning the application of section 41(d)(1) and paragraph (a) of this section to these facts.

Example 1. Computer hardware and software developed as a single product—(i) Facts. X is a telecommunications company that developed high technology telephone switching hardware. In addition, X developed software that interfaces directly with the hardware to initiate and terminate a call, along with other functions. X designed and developed the hardware and software together.

(ii) *Conclusion.* The telecommunications software that interfaces directly with the hardware is part of a package of software and hardware developed together by the taxpayer that is used by the taxpayer in providing services in its trade or business. Accordingly, this paragraph (c)(6) does not apply to the software that interfaces directly with the hardware as described in paragraph (c)(6)(ii)(C) of this section, and eligibility for the research credit is determined by examining the combined software-hardware product as a single product.

Example 2. Internal use software; financial management—(i) Facts. X, a manufacturer, self-insures its liabilities for employee health benefits. X develops its own software to administer its self-insurance reserves related to employee health benefits. At the beginning of the development, X does not intend to

develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The software is developed for use in a general and administrative function because reserve valuation is a financial management function under paragraph (c)(6)(iii)(B)(1) of this section. Accordingly, the software is internal use software because it is developed for use in a general and administrative function.

Example 3. Internal use software; human resources management—(i) Facts. X, a manufacturer, develops a software module that interacts with X's existing payroll software to allow X's employees to print pay stubs and make certain changes related to payroll deductions over the internet. At the beginning of the development, X does not intend to develop the software module for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The employee access software module is developed for use in a general and administrative function because employee access software is a human resources management function under paragraph (c)(6)(iii)(B)(2) of this section. Accordingly, the software module is internal use software because it is developed for use in a general and administrative function.

Example 4. Internal use software; support services—(i) Facts. X, a restaurant, develops software for a Web site that provides information, such as items served, price, location, phone number, and hours of operation for purposes of advertising. At the beginning of the development, X does not intend to develop the Web site software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system. X intends to use the software for marketing by allowing third parties to review general information on X's Web site.

(ii) *Conclusion.* The software is developed for use in a general and administrative function because the software was developed to be used by X for marketing which is a support services function under paragraph (c)(6)(iii)(B)(3) of this section. Accordingly, the software is internal use software because it is developed for use in a general and administrative function.

Example 5. Internal use software—(i) Facts. X, a multinational manufacturer with different business and financial systems in each of its divisions, undertakes a software development project aimed at integrating the majority of the functional areas of its major software systems (Existing Software) into a single enterprise resource management system supporting centralized financial systems, human resources, inventory, and sales. X purchases software (New Software) upon which to base its enterprise-wide system. X has to develop software (Developed Software) that transfers data from

X's legacy financial, human resources, inventory, and sales systems to the New Software. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The financial systems, human resource systems, inventory and sales systems are general and administrative functions under paragraph (c)(6)(iii)(B) of this section. Accordingly, the Developed Software is internal use software because it is developed for use in general and administrative functions.

Example 6. Internal use software; definition of third party—(i) Facts. X develops software to interact electronically with its vendors to improve X's inventory management. X develops the software to enable X to interact with vendors and to allow vendors to initiate functions or review data on the taxpayer's system. X defines the electronic messages that will be exchanged between X and the vendors. X's software allows a vendor to request X's current inventory of the vendor's product, and allows a vendor to send a message to X which informs X that the vendor has just made a new shipment of the vendor's product to replenish X's inventory. At the beginning of development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties.

(ii) *Conclusion.* Under paragraph (c)(6)(vi)(E) of this section, X's vendors are not third parties for purposes of paragraph (c)(6)(iv) of this section. While X's software was developed to allow vendors to initiate functions or review data on the taxpayer's system, the software is not excluded from internal use software as set forth in paragraph (c)(6)(iv)(B) of this section because the software was developed to allow vendors to use the software to support X's inventory management, which is a general and administrative function of X.

Example 7. Not internal use software; third party interaction—(i) Facts. X, a manufacturer of various products, develops software for a Web site with the intent to allow third parties to access data on X's database, to order X's products and track the status of their orders online. At the beginning of the development, X does not intend to develop the Web site software for commercial sale, lease, license, or to be otherwise marketed to third parties.

(ii) *Conclusion.* The software is not developed primarily for internal use because it is not developed for use in a general and administrative function. X developed the software to allow third parties to initiate functions or review data on the taxpayer's system as provided under paragraph (c)(6)(iv)(B) of this section.

Example 8. Not internal use software; third party interaction—(i) Facts. X developed software that allows its users to upload and modify photographs at no charge. X earns revenue by selling advertisements that are displayed while users enjoy the software that X offers for free. X also developed software

that has interfaces through which advertisers can bid for the best position in placing their ads, set prices for the ads, or develop advertisement campaign budgets. At the beginning of the development, X intended to develop the software to enable X to interact with third parties or to allow third parties to initiate functions on X's system.

(ii) *Conclusion.* The software for uploading and modifying photographs is not developed primarily for internal use because it is not developed for use in X's general and administrative functions under paragraph (c)(6)(iii)(A) of this section. The users and the advertisers are third parties for purposes of paragraph (c)(6)(iv) of this section. Furthermore, both the software for uploading and modifying photographs and the advertising software are not internal use software under paragraph (c)(6)(iv)(B) of this section because at the beginning of the development X developed the software with the intention of enabling X to interact with third parties or to allow third parties to initiate functions on X's system.

Example 9. Not internal use software; commercially sold, leased, licensed, or otherwise marketed—(i) Facts. X is a provider of cloud-based software. X develops enterprise application software (including customer relationship management, sales automation, and accounting software) to be accessed online and used by X's customers. At the beginning of development, X intended to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties.

(ii) *Conclusion.* The software is not developed primarily for internal use because it is not developed for use in a general and administrative function. X developed the software to be commercially sold, leased, licensed, or otherwise marketed to third parties under paragraph (c)(6)(iv)(A) of this section.

Example 10. Improvements to existing internal use software—(i) Facts. X has branches throughout the country and develops its own facilities services software to coordinate moves and to track maintenance requests for all locations. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system. Several years after completing the development and using the software, X consults its business development department, which assesses the market for the software. X determines that the software could be sold at a profit if certain technical and functional enhancements are made. X develops the improvements to the software, and sells the improved software to third parties.

(ii) *Conclusion.* Support services, which include facility services, are general and administrative functions under paragraph (c)(6)(iii)(B) of this section. Accordingly, the original software is developed for use in general and administrative functions and is, therefore, developed primarily for internal use. However, the improvements to the software are not developed primarily for

internal use because the improved software was not developed for use in a general and administrative function. X developed the improved software to be commercially sold, leased, licensed, or otherwise marketed to third parties under paragraphs (c)(6)(iv)(A) and (c)(6)(v) of this section.

Example 11. Dual function software; identification of a third party subset—(i) Facts. X develops software for use in general and administrative functions that facilitate or support the conduct of X's trade or business and to allow third parties to initiate functions. X is able to identify a third party subset. X incurs \$50,000 of research expenditures for the software, 50% of which is allocable to the third party subset.

(ii) *Conclusion.* The software developed by X is dual function software. Because X is able to identify a third party subset, the third party subset is not presumed to be internal use software under paragraph (c)(6)(vi)(A) of this section. If X's research activities related to the third party subset constitute qualified research under section 41(d), and the allocable expenditures are qualified research expenditures under section 41(b), \$25,000 of the software research expenditures allocable to the third party subset may be included in computing the amount of X's credit, pursuant to paragraph (c)(6)(vi)(B) of this section. If, after the application of paragraph (c)(6)(vi)(B) of this section, there remains a dual function subset, X may determine whether paragraph (c)(6)(vi)(C) of this section applies.

Example 12. Dual function software; application of the safe harbor—(i) Facts. The facts are the same as in *Example 11*, except that X is unable to identify a third party subset. X uses an objective, reasonable method at the beginning of the software development to determine that the dual function software's use by third parties to initiate functions is reasonably anticipated to constitute 15% of the dual function software's use.

(ii) *Conclusion.* The software developed by X is dual function software. The software is presumed to be developed primarily for internal use under paragraph (c)(6)(vi)(A) of this section. Although X is unable to identify a third party subset, X reasonably anticipates that the dual function software's use by third parties will be at least 10% of the dual function software's use. If X's research activities related to the development or improvement of the dual function software constitute qualified research under section 41(d), without regard to section 41(d)(4)(E), and the allocable expenditures are qualified research expenditures under section 41(b), X may include \$12,500 (25% of \$50,000) of the software research expenditures of the dual function software in computing the amount of X's credit pursuant to paragraph (c)(6)(vi)(C) of this section.

Example 13. Dual function software; safe harbor inapplicable—(i) Facts. The facts are the same as in *Example 11*, except X is unable to identify a third party subset. X uses an objective, reasonable method at the beginning of the software development to determine that the dual function software's use by third parties to initiate functions is reasonably anticipated to constitute 5% of the dual function software's use.

(ii) *Conclusion.* The software developed by X is dual function software. The software is presumed to be developed primarily for X's internal use under paragraph (c)(6)(vi)(A) of this section. X is unable to identify a third party subset, and X reasonably anticipates that the dual function software's use by third parties will be less than 10% of the dual function software's use. X may only include the software research expenditures of the dual function software in computing the amount of X's credit if the software satisfies the high threshold of innovation test of paragraph (c)(6)(vii) of this section and X's research activities related to the development or improvement of the dual function software constitute qualified research under section 41(d), without regard to section 41(d)(4)(E), and the allocable expenditures are qualified research expenditures under section 41(b).

Example 14. Dual function software; identification of a third party subset and the safe harbor—(i) Facts. X develops software for use in general and administrative functions that facilitate or support the conduct of X's trade or business and to allow third parties to initiate functions and review data. X is able to identify a third party subset (Subset A). The remaining dual function subset of the software (Subset B) allows third parties to review data and provides X with data used in its general and administrative functions. X is unable to identify a third party subset of Subset B. X incurs \$50,000 of research expenditures for the software, 50% of which is allocable to Subset A and 50% of which is allocable to Subset B. X determines, at the beginning of the software development, that the processing time of the third party use of Subset B is reasonably anticipated to account for 15% of the total processing time of Subset B.

(ii) *Conclusion.* The software developed by X is dual function software. Because X is able to identify a third party subset, such third party subset (Subset A) is not presumed to be internal use software under paragraph (c)(6)(vi)(A) of this section. If X's research activities related to the development or improvement of Subset A constitute qualified research under section 41(d), and the allocable expenditures are qualified research expenditures under section 41(b), the \$25,000 of the software research expenditures allocable to Subset A may be included in computing the amount of X's credit pursuant to paragraph (c)(6)(vi)(B) of this section. Although X is unable to identify a third party subset of Subset B, 15% of Subset B's use is reasonably anticipated to be attributable to the use of Subset B by third parties. If X's research activities related to the development or improvement of Subset B constitute qualified research under section 41(d), without regard to section 41(d)(4)(E), and the allocable expenditures are qualified research expenditures under 41(b), X may include \$6,250 (25% x \$25,000) of the software research expenditures of Subset B in computing the amount of X's credit, pursuant to paragraph (c)(6)(vi)(C) of this section.

Example 15. Internal use software; application of the high threshold of innovation test—(i) Facts. X maintained separate software applications for tracking a variety of human resource (HR) functions,

including employee reviews, salary information, location within the hierarchy and physical location of employees, 401(k) plans, and insurance coverage information. X determined that improved HR efficiency could be achieved by redesigning its disparate software applications into one employee-centric system, and worked to develop that system. X also determined that commercially available database management systems did not meet all of the requirements of the proposed system. Rather than waiting several years for vendor offerings to mature and become viable for its purpose, X embarked upon the project utilizing older technology that was severely challenged with respect to data modeling capabilities. The improvements, if successful, would provide a reduction in cost and improvement in speed that is substantial and economically significant. For example, having one employee-centric system would remove the duplicative time and cost of manually entering basic employee information separately in each application because the information would only have to be entered once to be available across all applications. The limitations of the technology X was attempting to utilize required that X attempt to develop a new database architecture. X committed substantial resources to the project, but could not predict, because of technical risk, whether it could develop the database software in the timeframe necessary so that X could recover its resources in a reasonable period. Specifically, X was uncertain regarding the capability of developing, within a reasonable period, a new database architecture using the old technology that would resolve its technological issues regarding the data modeling capabilities and the integration of the disparate systems into one system. At the beginning of the development, X did not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The software is internal use software because it is developed for use in a general and administrative function. However, the software satisfies the high threshold of innovation test set forth in paragraph (c)(6)(vii) of this section. The software was intended to be innovative in that it would provide a reduction in cost or improvement in speed that is substantial and economically significant. In addition, X's development activities involved significant economic risk in that X committed substantial resources to the development and there was substantial uncertainty, because of technical risk, that the resources would be recovered within a reasonable period. Finally, at the time X undertook the development of the system, software meeting X's requirements was not commercially available for use by X.

Example 16. Internal use software; application of the high threshold of innovation test—(i) Facts. X undertook a software project to rewrite a legacy mainframe application using an object-oriented programming language, and to move

the new application off the mainframe to a client/server environment. Both the object-oriented language and client/server technologies were new to X. This project was undertaken to develop a more maintainable application, which X expected would significantly reduce the cost of maintenance, and implement new features more quickly, which X expected would provide both significant improvements in speed and reduction in cost. Thus, the improvements, if successful, would provide a reduction in cost and improvement in speed that is substantial and economically significant. X also determined that commercially available systems did not meet the requirements of the proposed system. X was certain that it would be able to overcome any technological uncertainties and implement the improvements within a reasonable period. However, X was unsure of the appropriate methodology to achieve the improvements. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The software is internal use software because it is developed for use in a general and administrative function. X's activities do not satisfy the high threshold of innovation test of paragraph (c)(6)(vii) of this section. Although the software meets the requirements of paragraphs (c)(6)(vii)(A)(1) and (3) of this section, X's development activities did not involve significant economic risk under paragraph (c)(6)(vii)(A)(2) of this section. X did not have substantial uncertainty, because of technical risk, that the resources committed to the project would be recovered within a reasonable period.

Example 17. Internal use software; application of the high threshold of innovation test—(i) Facts. X wants to expand its internal computing power, and is aware that its PCs and workstations are idle at night, on the weekends, and for a significant part of any business day. Because the general and administrative computations that X needs to make could be done on workstations as well as PCs, X develops a screen-saver-like application that runs on employee computers. When employees' computers have been idle for an amount of time set by each employee, X's application goes back to a central server to get a new job to execute. This job will execute on the idle employee's computer until it has either finished, or the employee resumes working on his computer. The ability to use the idle employee's computers would save X significant costs because X would not have to buy new hardware to expand the computing power. The improvements, if successful, would provide a reduction in cost that is substantial and economically significant. At the time X undertook the software development project, there was no commercial application available with such a capability. In addition, at the time X undertook the software development project, X was uncertain regarding the capability of developing a server application that could schedule and

distribute the jobs across thousands of PCs and workstations, as well as handle all the error conditions that occur on a user's machine. X commits substantial resources to the project. X undertakes a process of experimentation to attempt to eliminate its uncertainty. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The software is internal use software because it is developed for use in a general and administrative function. However, the software satisfies the high threshold of innovation test as set forth in paragraph (c)(6)(vii) of this section. The software was intended to be innovative because it would provide a reduction in cost or improvement in speed that is substantial and economically significant. In addition, X's development activities involved significant substantial resources to the development and there was substantial uncertainty that because of technical risk, such resources would be recovered within a reasonable period. Finally, at the time X undertook the development of the system, software meeting X's requirements was not commercially available for use by X.

Example 18. Internal use software; application of the high threshold of innovation test—(i) Facts. X, a multinational manufacturer, wants to install an enterprise resource planning (ERP) system that runs off a single database. However, to implement the ERP system, X determines that it must integrate part of its old system with the new because the ERP system does not have a particular function that X requires for its business. The two systems are general and administrative software systems. The systems have mutual incompatibilities. The integration, if successful, would provide a reduction in cost and improvement in speed that is substantial and economically significant. At the time X undertook this project, there was no commercial application available with such a capability. X is uncertain regarding the appropriate design of the interface software. However, X knows that given a reasonable period of time to experiment with various designs, X would be able to determine the appropriate design necessary to meet X's technical requirements and would recover the substantial resources that X commits to the development of the system within a reasonable period. At the beginning of the development, X does not intend to develop the software for commercial sale, lease, license, or to be otherwise marketed to third parties or to enable X to interact with third parties or to allow third parties to initiate functions or review data on X's system.

(ii) *Conclusion.* The software is internal use software because it is developed for use in a general and administrative function. X's activities do not satisfy the high threshold of innovation test of paragraph (c)(6)(vii) of this section. Although the software meets the requirements of paragraphs (c)(6)(vii)(A)(1) and (3) of this section, X's development

activities did not involve significant economic risk under paragraph (c)(6)(vii)(A)(2) of this section. X did not have substantial uncertainty, because of technical risk, that the resources committed to the project would be recovered within a reasonable period.

* * * * *

(e) *Effective/applicability dates.* Other than paragraph (c)(6) of this section, this section is applicable for taxable years ending on or after December 31, 2003. Paragraph (c)(6) of this section is applicable for taxable years beginning on or after October 4, 2016. For any taxable year that both ends on or after January 20, 2015 and begins before October 4, 2016, the IRS will not challenge return positions consistent with all of paragraph (c)(6) of this section or all of paragraph (c)(6) of this section as contained in the Internal Revenue Bulletin (IRB) 2015-5 (see www.irs.gov/pub/irs-irbs/irb15-05.pdf). For taxable years ending before January 20, 2015, taxpayers may choose to follow either all of § 1.41-4(c)(6) as contained in 26 CFR part 1 (revised as of April 1, 2003) and IRB 2001-5 (see www.irs.gov/pub/irs-irbs/irb01-05.pdf) or all of § 1.41-4(c)(6) as contained in IRB 2002-4 (see www.irs.gov/pub/irs-irbs/irb02-04.pdf).

John Dalrymple,
Deputy Commissioner for Services and Enforcement.

Approved: August 22, 2016.

Mark J. Mazur
Assistant Secretary of the Treasury (Tax Policy).

[FR Doc. 2016-23174 Filed 10-3-16; 8:45 am]

BILLING CODE 4830-01-P

DEPARTMENT OF DEFENSE

Office of the Secretary

32 CFR Part 236

[DOD-2014-OS-0097/RIN 0790-AJ29]

Department of Defense (DoD)'s Defense Industrial Base (DIB) Cybersecurity (CS) Activities

AGENCY: Office of the DoD Chief Information Officer, DoD.

ACTION: Final rule.

SUMMARY: This final rule responds to public comments and updates DoD's Defense Industrial Base (DIB) Cybersecurity (CS) Activities. This rule implements mandatory cyber incident reporting requirements for DoD contractors and subcontractors who have agreements with DoD. In addition, the rule modifies eligibility criteria to

permit greater participation in the voluntary DIB CS information sharing program.

DATES: *Effective Date:* This rule is effective on November 3, 2016.

FOR FURTHER INFORMATION CONTACT: Vicki Michetti, DoD's DIB Cybersecurity Program Office: (703) 604-3167, toll free (855) 363-4227, or OSD.DIBCSIA@mail.mil.

SUPPLEMENTARY INFORMATION:

Purpose: This final rule responds to public comments to the interim final rule published on October 2, 2015. This rule implements statutory requirements for DoD contractors and subcontractors to report cyber incidents that result in an actual or potentially adverse effect on a covered contractor information system or covered defense information residing therein, or on a contractor's ability to provide operationally critical support. The mandatory reporting applies to all forms of agreements between DoD and DIB companies (contracts, grants, cooperative agreements, other transaction agreements, technology investment agreements, and any other type of legal instrument or agreement). The revisions provided are part of DoD's efforts to establish a single reporting mechanism for such cyber incidents on unclassified DoD contractor networks or information systems. Reporting under this rule does not abrogate the contractor's responsibility for any other applicable cyber incident reporting requirement. Cyber incident reporting involving classified information on classified contractor systems will be in accordance with the National Industrial Security Program Operating Manual (DoD-M 5220.22 (<http://dtic.mil/whs/directives/corres/pdf/522022M.pdf>)).

The rule also addresses the voluntary DIB CS information sharing program that is outside the scope of the mandatory reporting requirements. By modifying the eligibility criteria for the DIB CS program, the rule enables greater participation in the voluntary program. Expanding participation in the DIB CS program is part of DoD's comprehensive approach to counter cyber threats through information sharing between the Government and DIB participants.

Benefits: The DIB CS program allows eligible DIB participants to receive Government furnished information and cyber threat information from other DIB participants, thereby providing greater insights into adversarial activity targeting the DIB. The program builds trust between DoD and DIB and provides a collaborative environment for participating companies and DoD to share actionable unclassified cyber threat information that may be used to

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
<hr/>)

**EXHIBIT NO. AWEC/205
RESPONSES TO DATA REQUESTS**

March 16, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to ICNU Data Request No. 001
March 2, 2018**

Request:

Reference the worksheet titled “Exhibit Support 2019_Tax Plan,” Tab “Rate Base Data”:

- a. Please provide workpapers supporting the calculation of accumulated deferred taxes identified in Cell “B13” in the amount of \$679,803,676;**
- b. Please provide a schedule itemizing the \$10,223,834,826 Gross Utility Plant in Service amount identified in Cell “B7” as of December 31, 2018 by FERC account and sub-account; and**
- c. Please provide workpapers supporting the calculation of Depreciation Reserves in the amount of \$4,762,772,580 in Cell “B9”**

Response:

- a. Detail for this number is provided in the file: 2019 Deferred Tax Detail.xls, which is found in the “Unbundling” folder of work papers supporting PGE Exhibit 200. Specifically, see rows 147 and 153 in column E of the “Summary Ms and ADIT” tab. There are no additional work papers for this amount because it represents the year-end 2018 rate base balance of accumulated deferred income taxes (ADIT), and is the result of decades of deferred income tax activity. Although the annual activity for each category of ADIT is calculated within PGE’s Tax Provision and PowerPlan systems, the details of that calculation are provided in PGE’s response to ICNU Data Request No. 010, part C.
- b. Attachment 001-A provides PGE’s Gross Utility Plant in Service as of December 31, 2018 by FERC account. There are no sub-accounts below the 300 level.
- c. Attachment 001-B provides PGE’s Depreciation Reserves as of December 31, 2018. The reserve reflects the portion of PGE’s cost of Electric Plant in Service that has been recovered over the accounting periods that asset costs have been classified as in service. The attachment demonstrates the types of activities that occur annually that are classified to the reserve including depreciation expense, retirements, cost of removal and salvage.

March 16, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to ICNU Data Request No. 002
March 2, 2018**

Request:

Reference the workpaper titled “Exhibit Support 2019_Tax Plan,” Tab “Ex 208 Rate Base Delta,” Cell “E11”:

- a. Please provide workpapers used to calculate the pro forma increase to depreciation reserves in the amount of \$33,840,507;**
- b. Please explain why the depreciation reserves increased by only \$33,840,507 in the referenced exhibit, in contrast to annual depreciation expenses of \$305,531,327 identified in Exhibit 203; and**
- c. Does the \$33,840,507 amount include incremental depreciation reserves associated with all utility plant in service, or just the incremental depreciation reserves associated only with new plant additions?**

Response:

PGE discovered an error in its forecasted year-end 2018 depreciation reserve balance as used in this filing (UE 335). In the file “Exhibit Support 2019_Tax Plan.xls”, Tab “Ex 208 Rate Base Delta”, Cell “E11”, the forecast for the depreciation reserve should have been approximately \$19.8 million higher to show a total increase of \$53.7 million (i.e., from \$4,727,981,385 to \$4,781,655,077). Attachment 002-A outlines the required adjustments that should have occurred (see Cell D55).

In determining the forecasted reserve balance for ratemaking purposes, PGE makes certain adjustments to the recorded balance on its general ledger. These adjustments are outlined below.

Cost of removal (COR)

Cost of removal that is collected through depreciation expense is reclassified from the depreciation reserve to a regulatory liability. The balance of the regulatory liability is added

back to the reserve balance which reduces net plant. There is no adjustment to depreciation expense.

Asset Retirement Obligations (ARO)

PGE recognizes AROs for legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-live assets.

Capitalized asset retirement costs (ARC) related to electric utility plant are depreciated over the estimated life of the related asset. The carrying amount of the ARO liability increases over time (accretion) with a corresponding accretion expense recorded.

PGE excludes the balance of the ARC asset and ARC depreciation reserve from net utility plant for ratemaking purposes. The difference between the timing of the recognition of ARC depreciation and accretion expense and the amount included in customers' prices (cost of removal noted above) is recorded as a regulatory asset or liability.

In UE 335, PGE properly reduced utility plant for the balance of the ARC asset. However, adjustments were not made to the reserve for the ARC depreciation balance and the regulatory liability. The sum of these two adjustments equate to a \$19,833,183 increase to the depreciation reserve as initially filed in this proceeding.

In Docket No. UE 319 (UE 319), net plant was properly decreased by the regulatory liability related to COR, but included the ARO liability balance instead of the net ARC asset and ARC depreciation balance. The result was an inadvertent understatement of net plant by \$49,713,400. Attachment 002-A shows these adjustments.

Although the rate base amounts were incorrect as noted above, the depreciation expense amounts were filed correctly in both UE 319 and UE 335.

March 16, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to ICNU Data Request No. 010
March 2, 2018**

Request:

Reference the worksheet titled "2019 Deferred Tax Detail," Tab "Summary Ms and ADIT":

- a. Please provide worksheets supporting the value of \$789,301,167 in Cell "E68" related to temporary book tax difference;
- b. Please provide worksheets supporting the hard-coded production tax credit carryforward values identified in Cells "C7:E10";
- c. Please provide an explanation and worksheets supporting the adjustment titled "2010003 7000000875 Stock Incentive Plan RMGMT" in the amount of \$3,502,315 on Row 97;
- d. Please provide an explanation and worksheets supporting the adjustment titled "2540003 3000000184 Boardman Severance" in the amount of \$2,774,773 on Row 128;
- e. Please provide an explanation and worksheets supporting the adjustment titled "2320052 7000000255 Healy Hab & Green Source Dev" in the amount of \$1,879,007 on Row 120;
- f. Please provide an explanation and worksheets supporting the adjustment titled "2320052 7000000254 Clean Wind Development Fund" in the amount of \$1,946,757 on Row 119;
- g. Please provide an explanation and worksheets supporting the adjustment titled "2320031 A/P Accrued Incentives" in the amount of \$7,128,796 on Row 115;
- h. Does the Company consider accrued incentives a source of cash in its lead lag study?;
- i. Please provide an explanation and worksheets supporting the adjustment titled "2320012 A/P - Vacation" in the amount of \$4,842,278 on Row 111;

- j. Does the Company consider accrued vacation a source of cash in its lead lag study?;**
- k. Please provide an explanation and workpapers supporting the adjustment titled “2290001 7000010758 Customer Storm Collection” in the amount of \$715,000 on Row 110;**
- l. Please provide an explanation and workpapers supporting the adjustment titled “2320033 A/P - Involuntary Severance” in the amount of \$426,107 on Row 116**

Response:

PGE’s work paper “2019 Deferred Tax Detail.xls” inadvertently contains misaligned numbers in the “Summary Ms and ADIT” tab under column G, rows 72 through 142. The misalignment, however, did not affect any PGE testimony, exhibits, other work papers, or 2019 test year revenue requirement. Attachment 010-A provides the corrected work paper, for use in the calculations described in parts c-g, i, and k-l, below.

- a. There are no work papers that support the value in Cell E68 of the work paper titled "2019 Deferred Tax Detail," Tab "Summary Ms and ADIT." The source for this number is a combination of two reports from PGE’s PowerTax software. PowerTax is the system utilized to calculate and track property-related deferred taxes. Attached in Attachment 010-B is an Excel workbook with three tabs. The first tab summarizes the key information from the other two tabs. The second and third tabs are extracted reports from PowerTax. The second tab provides the deferred tax balance for all utility property. The third tab contains the deferred tax balance related to the Carty Increment that PGE removed from rate base.
- b. The source for the hard-coded production tax credit carryforward values identified in Cells C7:E10 are detailed below.
 - 1) Cell C10 is the value reported in the 2016 Results of Operations report.
 - 2) Cell D7 is calculated in the attached work paper identified as Attachment 010-C (see cell O28).
 - 3) Cell D8 adjusts the 12/31/2016 balance to the balance after the 2016 tax return so that the balance at 12/31/2017 will be supported by the other activity reported in 2017.
 - 4) Cell D9 is the estimated utilization of PTCs recorded for the year ended 12/31/2017. It is supported by the attached report extracted from the Tax Provision system. The report is identified as Attachment 010-D (see cell B34).
 - 5) Cell D10 is supported by the attached report extracted from the Tax Provision system and ties to the 2017 Form 10K filed with the SEC. The report is identified as Attachment 010-E (see cell O16).
 - 6) Cell E7 is calculated on the attached work paper identified as Attachment 010-F (see cell O28).

- 7) Cell E9 is the estimated utilization of PTCs during 2018. It is supported by the attached report extracted from the Tax Provision system. The report is identified as Attachment 010-G (see cell B29).
- 8) Cell E10 is supported by the attached report extracted from the Tax Provision system. The report is identified as Attachment 010-H (see Cell L13).

Attachments 010-B, 010-C, 010-D, 010-E, 010-F, 010-G, and 010-H are protected and subject to Protective Order No. 18-047.

- c. The referenced item is not an adjustment, but rather an accumulated deferred income tax (ADIT) asset based on the different book/tax treatment of PGE's stock incentive costs when calculating income taxes. There are no specific work papers for this balance because the amount is developed and updated by PGE's Tax Provision and PowerTax systems. The year-end balances in columns D and E, however, can be calculated based on the beginning balances, listed in Columns C, and the Schedule M activity listed in columns G and H. For Column E the 2018 balance is calculated as follows:

2018 ADIT balance, column E equals:

(2017 ADIT balance) + (2018 Schedule M activity * Current blended statutory tax rate); or

(Column D) + (Column H * 27.5%)

Row 97, column E:

\$3,502,315 = \$3,502,315 + (0 * 27.5%)

For column D, the calculation is the same as above, but also includes the revaluation of the 2016 ADIT balance based on the federal tax legislation enacted on December 22, 2017.

2017 ADIT balance, column D equals:

((2016 ADIT balance / Prior blended statutory tax rate) * Current blended statutory tax rate) + (2017 Schedule M activity * Current blended statutory tax rate); or

((Column C / 40%) * 27.5%) + (Column G * 27.5%)

Row 97, column D:

\$3,502,315 = ((\$5,029,341 / 40%) * 27.5%) + (\$162,668 * 27.5%)

- d. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's Boardman severance costs when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.
- e. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's renewable portfolio costs when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.

- f. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's Renewable Fixed Option revenues (Schedules 7 and 32) when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.
- g. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's incentive costs when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.
- h. PGE included accrued incentives in the Expense Lag component of the Lead-Lag study provided in work papers to PGE Exhibit 200. Accrued incentives are also a component of book expenses that are included when calculating taxable income, income tax expense, and deferred taxes. Ultimately, row 115 of the referenced work paper refers to an ADIT asset and not accrued incentives themselves. This tax effect is also part of the timing of tax payments that is included in the Lead-Lag study.
- i. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's payroll vacation costs when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.
- j. PGE did not include accrued vacation in the Lead-Lag study provided in work papers to PGE Exhibit 200. Accrued vacation, however, is a component of book expenses that is included when calculating taxable income, income tax expense, and deferred taxes. Ultimately, row 111 of the referenced work paper refers to an ADIT asset and not accrued vacation itself. Consequently, the timing of tax payments, which is included in the Lead-Lag study, reflects the impact of this item.
- k. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's storm reserve costs when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.
- l. The referenced item is not an adjustment, but rather an ADIT asset based on the different book/tax treatment of PGE's involuntary severance expenses (that are accrued and paid upon employee termination) when calculating income taxes. For all other aspects of this response, see PGE's response to part c, above.

April 18, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 017
April 4, 2018**

Request:

Please provide workpapers supporting the calculation of Excess Tax Reserves (i.e. Excess Deferred Federal Income Taxes) as defined in § 13001(d) of the TCJA. Please also include workpapers supporting the amortization of the Excess Tax Reserve balance to net operating income. If the average rate assumption method was used please provide the amortization calculation by FERC account and property vintage.

Response:

Attachment 017-A provides calculation of the estimated Excess Tax Reserve as a result of the TCJA. The re-measurement of 2017 utility deferred taxes is \$304 million, which includes the re-measurement of unprotected deferred taxes of (\$17 million), protected deferred taxes of \$233 million, and re-measurement of the gross-up of \$88 million. These amounts are still considered estimated until PGE files its 2017 tax return on or before the extended due date of October 15, 2018.

The average rate assumption method was used to calculate the amortization of the Excess Tax Reserve. The actual amortization is calculated using both the PowerTax and Tax Provision modules and is reported in the Tax Provision module. The estimated calculation of the ARAM amortization for 2018 is in the Tax Provision report located in Attachment 017-B. The amortization by FERC account and property vintage is not available on a work paper. It is imbedded in thousands of system calculations. Attachment 017-B is protected information and subject to Protective Order No. 18-047.

April 18, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 026
April 4, 2018**

Request:

Please provide forecast transfers to plant by project and by month over the period 1/1/2018 to 12/31/2018.

Response:

Attachment 026-A provides the requested information.

Attachment 026-A is protected and subject to Protective Order No. 18-047.

April 26, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 039
April 12, 2018**

Request:

Reference PGE/1300 at 33:12-14 where PGE states that "PGE's resources are system resources. Any energy storage facility on the system controlled by PGE provides integrating renewable energy resources as a primary system benefit." Based on this statement, please explain whether:

- a) Port Westward 2 "provides integrating renewable energy resources as a primary system benefit" and if not, why not?
- b) Port Westward 1 "provides integrating renewable energy resources as a primary system benefit" and if not, why not?
- c) Carty "provides integrating renewable energy resources as a primary system benefit" and if not, why not?
- d) Beaver "provides integrating renewable energy resources as a primary system benefit" and if not, why not?
- e) Coyote Springs "provides integrating renewable energy resources as a primary system benefit" and if not, why not?
- f) PGE's hydroelectric resources "provides integrating renewable energy resources as a primary system benefit" and if not, why not?

Response:

PGE objects to this request on the basis that it is vague and irrelevant. The section referenced in PGE Exhibit 1300 pertains to energy storage facilities. This data request is asking about PGE's generating facilities. Without waiving its objection, PGE responds as follows:

PGE's resources represent a diverse combination of power supply options used to reliably and economically balance supply and demand. PGE considers load balancing to be a primary system benefit of its resource portfolio as a whole, which includes the generating facilities identified above. Integrating variable energy resources is one component of balancing load. Depending on

the specific capabilities of each resource and the system's requirements (e.g., energy, flexibility, peaking capacity, reserves, etc.) during any given period, each resource is capable of contributing, either partially or fully, to integrating variable energy resources as a "primary system benefit." For example, flexible resources, such as some of PGE's hydroelectric resources and gas facilities, are capable of responding to quicker, more frequent changes in variable energy resource output. Some of PGE's larger gas facilities are capable of providing energy and ramping when variable energy resources are not consistently producing or are experiencing gradual deviations in output. As previously mentioned, the task of variable energy resource integration is accomplished using a portfolio of resources that can serve several functions depending on system conditions.

May 1, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 045
Dated April 4, 2018**

Reference Exhibit Support 2019 _Tax Plan, Tab "Sch Ms+ Tax CRs":

- a. Please provide workpapers to support the calculation of the \$7,011,795 associated with Excess Deferred Federal Income Taxes.**
- b. Please reconcile the \$7,011,795 amount with the amount reported in "UE 335 AWEC DR 017 Attach B -CONF.xlsx."**
- c. Please explain PGE's proposal for Excess Deferred Federal Income Taxes associated with unprotected book-tax differences for Schedule M Items other than depreciation.**

Response:

- a. The report from the Tax Provision system that supports the \$7,011,795 associated with Excess-Deferred Federal Income taxes is included as Attachment 045-A.

Attachment 045-A is protected information and subject to Protective Order No. 18-047.

- b. The difference between the \$7 million in the referenced report and the amount reported in "UE 335_AWEC DR 017_Attach B_CONF" is an update to a more current 2018 forecast that was filed as a part of PGE's tax deferral filing (Docket No. UM 1920) on April 13, 2018.
- c. PGE has filed a request to defer, for later rate making treatment, the expected net benefits associated with the tax rules and provisions implemented through the tax legislation enacted on December 22, 2017. The calculation of the net benefit includes the net excess accumulated deferred income tax that is "unprotected" and not subject to IRS normalization rules and was amortized at year-end 2017, in accordance with GAAP.

May 1, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 046
Dated April 4, 2018

Reference "UE 335 AWEC DR 017 Attach B CONF.xlsx":

- a. Please provide this workpaper with formulas and links intact.**
- b. Please provide a description for each line in the referenced attachment.**
- c. If PGE does not have the vintage data available, please provide PGE's calculation of EDFIT and ADIT as of 12/31/2017 by FERC Account.**
- d. When calculating the ARAM amounts for plant ADIT balances, please explain how PGE estimated the deferred taxes by plant vintage for mass property accounts. Was a theoretical reserve calculation performed in developing the vintage data, similar to what is done in preparing PGE's depreciation study? Please explain.**
- e. Do the referenced amounts include deferred taxes associated with amortization or depreciation of software?**

Response:

- a. The information provided in UE 335_AWEC DR 017_Attach B_CONF is an output report from our Power Plan Tax Provision system. There are no formulas or links in the work paper because the amounts are embedded in thousands of system calculations.
- b. Each line on the report represents an accumulation of temporary differences considered to be either Regulatory Assets (RA) or Regulatory Liabilities (RL) by jurisdiction.
 - 1. M Item column: The total of all temporary differences related to the regulatory classification/jurisdiction.
 - 2. Total Tax: Total of current and deferred tax related to the M Items. This is the key column. Without normalization requirements, a temporary difference will create an equal and offsetting current and deferred tax such that the total tax is zero. However, when the ARAM rate associated with the temporary difference is not equal to the current rate, there is a resulting total tax. Thus, the total tax is caused by the ARAM on these temporary items.
 - 3. Current Impact: The current tax related to the M-Items (at the current tax rate).
 - 4. Deferred Impact: The deferred impact related to the M-Items (new incurring differences at the current rate and reversing differences at the ARAM rate).

- c. As required by GAAP, the Excess Deferred Federal Income Tax (EDFIT) is removed from accumulated deferred income tax (ADIT). This is accomplished through a debit to FERC account 190: Accumulated Deferred Income Taxes. The offsetting credit is recorded to FERC account 254: Other Regulatory Liabilities.
- d. Plant additions are entered into PowerTax through an interface with the Continuing Property Record (CPR). As those records are entered into PowerTax, PowerTax creates a vintage record by Tax Class. Book depreciation is one of the factors in calculating the turnaround of plant temporary differences. Tax Classes are grouped into Book Depreciation Groups that are the same Book Depreciation Groups that are in the plant depreciation module. Book depreciation is loaded into PowerTax by Book Depreciation Group through an interface with the plant depreciation module. Book depreciation is allocated to the vintage Tax Class records using a similar method to the plant depreciation module depreciation calculation. The book depreciation reserve in PowerTax is reconciled to the FERC book depreciation reserve as reported in the FERC Form 1 annually.
- e. Yes, the referenced amounts include deferred taxes associated with amortization or depreciation of software.

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 099
Dated May 4, 2018**

Request:

Please identify the ratemaking methodology that PGE is currently using to recover severance payments associated with the Boardman retirement.

Response:

Forecasted severance payments related to the cessation of coal-fired operations at Boardman are being collected through PGE Schedule 145 and are not included in the UE 335 revenue requirement.

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 100
Dated May 4, 2018**

Request:

Reference PGE's response to ICNU data request 10, Attachment A: Please provide an explanation for the deferred tax item titled "Stock Incentive Plan RMGMT", including a description of both the expense timing for book purposes and the deduction timing for tax purposes.

Response:

The deferred tax item titled "Stock Incentive Plan RMGMT" represents the timing difference of when the costs of stock incentive plans are recorded for book versus tax. For book purposes these costs are expensed, straight line, over the vesting period. For tax purposes, the costs are deducted on the vesting date. The difference in timing between when the expense is recognized for book and tax purposes, creates a temporary difference that results in a deferred tax asset or liability.

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 104
Dated May 4, 2018**

Request:

Reference PGE's response to AWEC data request 45, sup-part C: Please provide detail for each unprotected book-tax difference item, indicating, as of December 31, 2017, the amount of accumulated deferred taxes before re-measurement at the 21% federal income tax rate, the amount of accumulated deferred federal income taxes after re-measurement, and the re-measurement gain or loss, which PGE appears to have recorded on its books in 2017.

Response:

Attachment 104-A provides a list of all book-tax differences, the accumulated deferred income tax (ADIT) before re-measurement, and the ADIT after re-measurement. The re-measurement loss recorded on the books as of December 31, 2017 is \$16,893,465, which is in cell F190 of Attachment104-A.

Attachment 104-A is protected information and subject to Protective Order No. 18-047.

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 105
Dated May 4, 2018**

Request:

Reference PGE's response to AWEC data request 45, sup-part C: Did PGE record a regulatory liability when it amortized the re-measurement gains associated with unprotected EDFIT in 2017? If yes, please provide workpapers supporting the calculation of the regulatory liability.

Response:

The total re-measurement of the "unprotected" deferred income tax balance resulted in a loss of \$16,327,486. AWEC Data Request No. 104, Attachment 104-A, provides the calculation for that amount (sum of cells F187 and G187). Of the \$16,327,486 re-measurement of unprotected deferred items, \$565,978 was recorded as a regulatory liability as of December 31, 2017 (cell F189).

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 106
Dated May 4, 2018**

Request:

Reference PGE's response to AWEC data request 25:

- a) Please provide the monthly transfers to plant, by project, for 2015 in the same format as the attachments to the referenced data request.**
- b) Please also consolidate the capital additions from 2017 into a single workpaper.**
- c) For the capital additions provided for calendar years 2015 through 2017, please identify each project by function, in the same manner as done for the 2018 capital additions in response to AWEC data request 26.**

Response:

Attachment 106-A provides the 2015-2017 Monthly Plant Additions to address parts (a) through (c). Asset Retirement Cost (ARC) associated with the Asset Retirement Obligations (ARO) have been excluded from all monthly plant additions data.

Company			Portland General Electric													
Ferc Activity Code			Addition													
Year			2017													

Funding Project System																
Number	Funding Project Description	Function	201701	201702	201703	201704	201705	201706	201707	201708	201709	201710	201711	201712	Grand Total	
P35485	Replace Remaining D1D Cables	Distribution Plant	\$	(1,065)			\$	(9)							\$ (1,074)	
P35501	Hayden Island Substation Upgrades	Distribution Plant		\$	18		\$	0							\$ 19	
P35514	OG - Build Harriet Power House	Hydro Production		\$	1,672	\$ 924	\$ 1,608	\$ (31)	\$ (22)	\$ (24)					\$ 4,128	
P35522	Desktop Computer Fitness Program	General Plant	\$ 30,667	\$ 15,115	\$ 3,547	\$ 25,930	\$ 198,119	\$ (1,190)	\$ 7,902	\$ (4,075)	\$ (210)	\$ 457	\$ 106	\$ 4,331	\$ 280,698	
P35542	BR: Purchase Communication Radios	General Plant						\$	(22)						\$ (22)	
P35553	BR - Replace 4.16 kV Switchgear	Other Production			\$	(7,979)									\$ (7,979)	
P35554	Voice Replacement with Cisco Voip	General Plant								\$	546	\$ (2)	\$ 200,541	\$ 1,243	\$ 202,328	
P35556	Avian Protection Program	Distribution Plant	\$ 16,636	\$ 8,010	\$ 26,896	\$ 46,685	\$ 23,085	\$ 42,558	\$ 33,301	\$ 34,792	\$ 31,134	\$ 42,100	\$ 11,672	\$ 25,328	\$ 342,196	
P35565	PSES - Generation Site Paving	Hydro Production	\$ 2,686	\$ (1)	\$ (2)	\$ 1,431	\$ 82,981	\$ (0)	\$ 85,965	\$ 101,674	\$ (32)	\$ 29	\$ 218,815	\$ 174,405	\$ 667,951	
P35570	West Union - 115kV Conversion	Distribution Plant		\$	1,975	\$ 12	\$ 0	\$ -				\$	1,939	\$ -	\$ 1,534,123	
P35571	Shute Substation - Build New Sub	Distribution Plant	\$ 3,549	\$	25,465	\$	\$ -	\$ 0		\$	568				\$ 29,582	
P35572	Build New Rock Creek Substation	Distribution Plant		\$	312	\$ 22,006	\$ 781	\$ 92,088	\$ 752	\$ 24,896	\$ (35)	\$ 97,724	\$ 567	\$ 123,730	\$ 620	
P35573	Ruby - 115kV Conversion	Distribution Plant								\$	25				\$ 25	
P35591	As-Built Drawings - Generation	Hydro Production	\$ 117,237	\$ 131,475	\$ 61,624	\$ 68,913	\$ 29,535	\$ 67,523	\$ 30,235	\$ 10,145	\$ 23,486	\$ 65,004	\$ 69,068	\$ 120,731	\$ 794,975	
P35619	CET Install Oracle CC&B/MDM Systems	General Plant	\$ 328,636	\$ 54,377	\$ 32,989	\$ 4,512	\$ 2,066,799	\$ 287,270	\$ (58,932)	\$ 918,711	\$ 46,617	\$ 59,548	\$ 263,799	\$ 963,879	\$ 4,968,204	
P35631	Sunset - D1X Transformer Upgrades	Distribution Plant	\$ 31,559	\$ 5,121	\$ 7,015	\$ 3,389	\$ 19,512	\$ 8,139	\$ (1,495)	\$ (5,295)	\$	\$ -	\$ -	\$ 53	\$ 67,997	
P35650	Emergent Radio Equipment	General Plant	\$ 258	\$ 2,882	\$ 1,361	\$ 2,543	\$ 10,835	\$ 6,395	\$ 4,192	\$ 4,754	\$ 1,327	\$ (2,985)	\$ 550	\$ 337	\$ 32,448	
P35666	Build Fiber Route West on HWY 26	General Plant						\$ 565,072	\$ 5,735	\$ 5,090	\$ 759	\$ 795	\$ 99	\$ 28	\$ 577,577	
P35669	Underground Core Crew Bldg Purchase	General Plant		\$	2,514										\$ 2,514	
P35672	ETRM Risk Management Consolidation	General Plant	\$ (43,313)	\$ 150,638	\$ (70,385)	\$ (16,427)	\$ 44,715	\$ (743)	\$ 14	\$ (16)					\$ 64,483	
P35679	Construct Marquam Project	General Plant	\$ 271,904	\$ 28		\$	\$ -	\$ 0	\$ 58		\$	\$ -	\$ -	\$ 290,486	\$ 562,475	
P35683	EMS Readiness Center Enhancement	General Plant	\$ 2,914	\$ 2,567	\$ 2,931	\$ 4,357	\$ 1,258	\$ 462	\$ 321	\$ 1,001	\$ (5)	\$ (54)	\$ 37	\$ 38	\$ 15,829	
P35688	BI & Data Managment for PGE	Intangible Plant	\$ 14,760	\$	\$ 5,613										\$ 20,373	
P35692	CET - IVR Fitness - Remove Barriers	Intangible Plant	\$ (69,617)	\$ (40,106)	\$ 7,384	\$ (133,230)				\$	170,600				\$ (64,968)	
P35706	Web CMS Replacement	Intangible Plant		\$	\$ 5,940	\$ 12,150	\$	\$ 9,660	\$ 2,490		\$	\$ -	\$ 1,260	\$ -	\$ 31,500	
P35709	Replace Emergency Generators-WTC	Other Production		\$	\$ 9,706										\$ 9,706	
P35760	Build Fiber Port Westward - Rainier	General Plant						\$	11,467	\$	5,608				\$ 17,075	
P35769	Construct Carty Generating Plant	Other Production	\$ (1,666,154)	\$ (201,001)	\$ 3,757,763	\$ (546,877)	\$ 176,671	\$ (878,530)	\$ 203,080	\$ 1,021,868	\$ 1,127,795	\$ (387,968)	\$ 7,534	\$ 296,095	\$ 2,910,277	
P35782	Relocate Hillsboro Customer Office	General Plant	\$ (0)												\$ (0)	
P35802	Horizon Phase II Project	Distribution Plant	\$ 16,590	\$ 813,203	\$ 18,098	\$ 26,511	\$ 5,005	\$ 57,266	\$ (269)	\$ 12,786,030	\$ 94,729	\$ 8,122,738	\$ 4,490,288	\$ 179,816	\$ 26,610,005	
P35815	Abernethy Substation Capacity Addn	Distribution Plant	\$ 4,164,721	\$ 8,077	\$ 103,076	\$ (190)	\$ 9,643	\$ 1,401	\$ 1,840	\$ 134,284	\$ 55,144	\$ 34,732	\$ 39,101	\$ -	\$ 4,551,828	
P35820	Estacada Capacity Addition	Distribution Plant	\$ 966,967	\$ 132,610	\$ 213,179	\$ 69	\$ (1,133)	\$ 712	\$ (493)	\$ (544)		\$ 99,610	\$ 278	\$ 425	\$ 1,411,680	
P35828	Faraday Switchyard 115kV Upgrade	General Plant		\$	(13)	\$	\$ 2	\$ (0)	\$ 1,758	\$	(1)				\$ 1,745	
P35831	X-Phase Synchrophasor Installation	Transmission Plant	\$ 1,522	\$ 8,717	\$ 146	\$ 3	\$ 2,032	\$ 4,400	\$ 41	\$ (41)	\$ 22	\$ (27)	\$ 31	\$ 0	\$ 16,847	
P35834	Round Butte Transmission Upgrades	General Plant		\$ 63,997	\$	\$ -			\$ (144)						\$ 63,852	
P35835	Portland Service Center Upgrade	General Plant	\$ 2,432	\$ 2,621	\$ 864		\$	(0)							\$ 5,917	
P35842	N. Plains - Pumpkin Ridge Recond.	Distribution Plant	\$ 864	\$ 1,923	\$ 22,833	\$ (225)	\$ (106)	\$ 122	\$ (56)	\$ (55)	\$ 16	\$ 1,562	\$ 31	\$ 783	\$ 27,691	
P35844	Corporate Furniture Purchases	General Plant	\$ 651												\$ 651	
P35846	CPP Switch Replacement	Distribution Plant	\$ 32,225	\$ 1,555	\$ 5,843	\$ 62,192	\$ 1,456	\$ 7,792	\$ (166)	\$ (426)	\$ 40,263	\$ 101,602	\$ 38,910	\$ 121,179	\$ 412,425	
P35849	PeopleSoft HR 9.2 Upgrade	General Plant	\$ 3,663	\$ 6,453	\$ 170,989	\$ 2,441	\$ 420	\$ 2,975,251	\$ 133,182	\$ 1,120	\$ (1,134)	\$ 47,191	\$ 1,080	\$ 388,365	\$ 3,729,021	
P35853	PeopleSoft Financials 9.2 Upgrade	Intangible Plant	\$ 314,650	\$ (234,458)	\$ 216,913	\$ (353,293)	\$ (7)								\$ (56,194)	
P35855	AMI Infrastructure Improvements	General Plant	\$ 106,824	\$ 41,651	\$ 52,728	\$ 56,013	\$ 18,208	\$ 32,705	\$ 20,922	\$ 47,261	\$ 53,231	\$ 39,866	\$ 9,842	\$ 8,402	\$ 487,653	
P35860	Application Password Vaulting	General Plant								\$ 55,098	\$ 225,230	\$ -	\$ 3,684,394	\$	\$ 3,964,722	
P35861	Network Access Management	General Plant	\$ 13,070	\$ 30,539	\$ (357)	\$ (138)	\$ (64)	\$ (26)	\$ 369,380		\$	103	\$ -	\$ -	\$ 412,508	
P35866	App Segmentation	Intangible Plant	\$ 1,085,167	\$ 1,519	\$ 34,781	\$ (39,292)	\$ 304	\$ 29,189	\$ 338	\$ 1,946					\$ 1,113,952	
P35881	IT for Facilities & Communications	General Plant	\$ 5,412	\$ 16,375	\$ 1,427	\$ 11,771	\$ 2,141	\$ 2,131	\$ 9,744	\$ 13,961	\$ 4,716	\$ 26,439	\$ 6,290	\$ 6,562	\$ 106,969	
P35890	Purchase Distribution Transformers	Distribution Plant	\$ 1,037,259	\$ 1,467,879	\$ 987,629	\$ 199,229	\$ 338,065	\$ 640,276	\$ 911,016	\$ 1,024,271	\$ 566,273	\$ 886,787	\$ 1,011,535	\$ 780,337	\$ 9,850,556	
P35892	Purchase Customer Meters	Distribution Plant	\$ 689,272	\$ 120,646	\$ 110,415	\$ 398,878	\$ 182,016	\$ 250,257	\$ 189,105	\$ 1,016,396	\$ 210,919	\$ 121,860	\$ 314,007	\$ 179,444	\$ 3,783,214	
P35894	Communications Fitness	General Plant	\$ 249,887	\$ 118,234	\$ 130,671	\$ 328,998	\$ 79,793	\$ 147,347	\$ 83,152	\$ 40,161	\$ 100,714	\$ 67,936	\$ 225,524	\$ 830,916	\$ 2,403,333	
P35902	CIP System Upgrades	General Plant		\$ (136,026)		\$	\$ -								\$ (136,026)	
P35907	Barnes Battle Creek Reconductor	Distribution Plant	\$ 11,944	\$ 172	\$ (188)	\$ (83)	\$ (39)	\$ 25	\$ (21)						\$ 11,810	
P35908	SAM: Proactive UG Cable Program	Distribution Plant	\$ 239,809	\$ 1,736,236	\$ 993,010	\$ 1,421,651	\$ 4,264,140	\$ (4,896,531)	\$ 2,078,277	\$ 825,327	\$ 1,943,253	\$ 1,501,733	\$ 1,065,070	\$ 534,089	\$ 11,706,064	
P35910	KB Pipe: Dewater Allen Bros Slope	Other Production		\$	78										\$ 78	
P35914	Substation Fitness 2015-2018	Distribution Plant	\$ 400,980	\$ 209,250	\$ 151,586	\$ 79,450	\$ 89,165	\$ 695,430	\$ 65,481	\$ 43,180	\$ 368,306	\$ 528,184	\$ 131,961	\$ 1,284,933	\$ 4,047,906	
P35916	PW: Install Modular CT Insulation	Other Production					\$	\$ 1,312,457	\$ 9,478	\$ (188)	\$ (27,839)	\$ (137)	\$ 47	\$ 93	\$ 1,293,911	
P35920	Corporate Security SoftwareFailover	Intangible Plant	\$ 40	\$ 2,608							\$	\$ -	\$ -	\$ 440	\$ 3,088	
P35924	Distribution System Construction II	Distribution Plant	\$ 1,873,085	\$ 2,487,904	\$ 4,567,156	\$ 5,154,640	\$ 5,071,381	\$ 9,276,280	\$ 2,838,746	\$ 4,905,040	\$ 5,308,182	\$ 2,173,503	\$ 4,056,034	\$ 3,722,908	\$ 51,434,860	
P35925	Dist. Customer Line Construction II	Distribution Plant	\$ 2,847,941	\$ 2,234,546	\$ 2,605,413	\$ 2,196,334	\$ 1,958,351	\$ 5,373,339	\$ 1,867,445	\$ 2,219,002	\$ 3,261,076	\$ 1,331,004	\$ 2,651,846	\$ 3,143,743	\$ 31,690,040	
P35932	Upgrade Maximo for IT	Intangible Plant					\$	\$ 1,106,497	\$ 960	\$ (893)	\$ (319)	\$ (621)	\$ 251	\$ 10,746	\$ 1,116,621	
P35937	NF: Generator 2 Rewind	Hydro Production	\$ 857	\$ 22	\$ 1,694	\$ (1)	\$ 711	\$ (4)	\$ 4						\$ 3,283	
P35943	RB: Install Xfmr Depressurization	Transmission Plant		\$ 820	\$ 2,567	\$ 150									\$ 3,537	
P35946	RB: Replace VAR-4 Transformer	Transmission Plant	\$ 11,087	\$ 14,084	\$ 785	\$ (1,855)	\$ (19)	\$ (9,883)		\$	(107)				\$ 14,091	

Funding Project System																	
Number	Funding Project Description	Function	201701	201702	201703	201704	201705	201706	201707	201708	201709	201710	201711	201712	Grand Total		
P35956	BR: Upgrade MCC's for HRSG's	Other Production	\$ 47,251	\$ 40,190	\$ 18,697	\$ (980)	\$ 2,637	\$ 6,473	\$ 3,652			\$ -	\$ 579,536	\$ 176,728	\$ 874,184		
P35959	WSH Structural/Reliability Upgrades	Hydro Production	\$ (98,011)	\$ 44,262	\$ 96,340	\$ 8,712	\$ 47,684	\$ 208,976	\$ 1,523,259	\$ 18,175	\$ 226,853	\$ 5,663,764	\$ 148,767	\$ 3,218,996	\$ 11,107,778		
P35980	PCB Transformer Replacement	Distribution Plant	\$ 601,902	\$ 645,749	\$ 1,035,338	\$ 981,189	\$ 1,257,423	\$ 1,610,706	\$ 1,135,092	\$ 1,632,335	\$ 1,386,654	\$ 1,556,039	\$ 1,160,164	\$ 1,187,305	\$ 14,189,896		
P35995	Downtown UG Core Cable Replacement	Distribution Plant	\$ 110,119	\$ 110,279	\$ 2,641	\$ (1,459)	\$ 119,776	\$ 300,036	\$ 101,965	\$ 70,542	\$ 215,489	\$ 239,805	\$ 232,037	\$ 116,209	\$ 1,617,438		
P36003	NERC CIPv5 Compliance Program	General Plant	\$ -	\$ 1,202	\$ -										\$ 1,202		
P36015	Remediation/Decom Vacant Land	General Plant	\$ (1,059)	\$ 13	\$ (35)	\$ (13)	\$ (6)	\$ (3)	\$ 3						\$ (1,101)		
P36019	Hemlock substation Install ATS	General Plant	\$ (374)	\$ 1,562	\$ (61)	\$ 3,680	\$ 1,426			\$ 0	\$ 924	\$ 11,064	\$ 5	\$ 8	\$ 18,235		
P36020	BLC Video Conference System	General Plant		\$ 4,302	\$ -										\$ 4,302		
P36036	Canemah-Sullivan 57kV Project	General Plant	\$ 7,906	\$ 61,629	\$ 33,693	\$ 28,305	\$ 16,496	\$ 5,759	\$ 4,074,243	\$ 212,502	\$ 37,471	\$ 126,554	\$ 96,381	\$ 1,079,903	\$ 5,780,842		
P36039	Harborton Reliability Project	Distribution Plant		\$ 2,680,258	\$ (493,020)	\$ 75,116	\$ 42,140	\$ 633	\$ (1,555)	\$ 2,977	\$ 1,640	\$ 3,694	\$ -	\$ -	\$ 2,311,882		
P36042	Tektronix Substation Upgrade	Distribution Plant		\$ 3,557,113	\$ 72,634	\$ 13,415	\$ 6,421	\$ 286	\$ 549	\$ 7,951	\$ 186,692	\$ 4,295,197	\$ 533,321	\$ 8,673,578			
P36043	Reconductor Pleasant Valley Baxter	Distribution Plant		\$ 606,663	\$ 43,891	\$ (838)	\$ 648	\$ (527)	\$ (438)	\$ 146	\$ (276)	\$ -	\$ -	\$ -	\$ 649,269		
P36046	Corporate Security Fitness	General Plant	\$ 1,324	\$ 13,981	\$ 39,694	\$ 2,229	\$ 59,997	\$ 25,058	\$ 116,203	\$ 4,586	\$ 1,732	\$ 25,764	\$ 58,171	\$ 348,739			
P36047	Eastport Comm Ofc Relocate &Upgrade	General Plant					\$ 443,176	\$ 253	\$ 1,419	\$ (8)	\$ 5,674	\$ 75	\$ 73	\$ 450,663			
P36052	Tualatin (TCC) Facilities Upgrade	General Plant	\$ 1,800	\$ 20,704	\$ 1,562,038	\$ (2,974)	\$ 153,332	\$ (827,297)	\$ 65	\$ (272)	\$ 70	\$ (200)	\$ 205	\$ 36	\$ 907,505		
P36054	CyberSecurity Fitness	General Plant	\$ 54,734	\$ 25,796	\$ (996)	\$ 2,024	\$ 114,807	\$ 4,831	\$ 247,572	\$ 61,158	\$ 485	\$ -	\$ -	\$ -	\$ 510,411		
P36055	Corporate Security Failover Part II	General Plant	\$ 35,648	\$ 26,912	\$ 3,086	\$ 31,375	\$ 1,348		\$ 29,335	\$ (354)	\$ 279	\$ -	\$ -	\$ 321,367	\$ 448,995		
P36056	Upgrade/Add Revenue Meters	Transmission Plant	\$ 931,677	\$ 17,780	\$ 42,015	\$ 1,171,806	\$ 235,786	\$ 407,679	\$ 281,596	\$ 18,394	\$ 36,145	\$ 490,816	\$ 125,898	\$ 471	\$ 3,760,062		
P36061	BR: CTG Rewind Program 2016 - 2018	Other Production	\$ 5,200	\$ 7,292	\$ (762)				\$ 3,637,015	\$ 734	\$ 84,446	\$ 18,294	\$ 12,322	\$ 683	\$ 3,765,223		
P36062	RB: Airgap Monitor Upgrade RealTime	Hydro Production		\$ 257,175	\$ (663)	\$ (307)	\$ (82)	\$ 90	\$ (148)	\$ 780	\$ 983	\$ 1,074	\$ 1,027	\$ 259,929			
P36065	Capital Furniture Purchases	General Plant	\$ 9,463												\$ 9,463		
P36067	PGE Facilities Fitness	General Plant	\$ 470,049	\$ 1,103	\$ 0	\$ (0)									\$ 471,152		
P36074	Repl Meters for Trans Manag Sys	Distribution Plant	\$ 171,526	\$ 29,078	\$ 430	\$ 10,489	\$ 13,182	\$ 5,179	\$ 1,599	\$ (90)	\$ 545	\$ 395	\$ 229	\$ (24)	\$ 232,539		
P36082	Purchase Two Repairman Trucks	General Plant	\$ 498	\$ 10	\$ (26)	\$ (10)	\$ (5)	\$ (2)	\$ 2						\$ 466		
P36087	PRB - Misc. Pumps, Valves, Motors	Hydro Production			\$ 10,001	\$ 6,313	\$ 1,898	\$ 88	\$ 20	\$ 1,479	\$ (35)	\$ 7	\$ 26	\$ 19,798			
P36088	SAM: Rivergate N Substation Rebuild	Transmission Plant		\$ 356,611						\$ 4,662,751	\$ 134,416	\$ 65,930	\$ 12,036	\$ 5,231,744			
P36093	Carver & PSC Pole Yards	General Plant	\$ 1,172			\$ -								\$ 1,172			
P36101	Substation Communication Upgrade	General Plant	\$ 37,327	\$ 40,032	\$ 36,815	\$ 96,725	\$ 78,579	\$ 123,123	\$ 117,587	\$ 69,448	\$ 265,413	\$ 130,307	\$ 4,289,883	\$ (4,292,021)	\$ 993,218		
P36105	2016/17 Dispatchable Standby Gen	Other Production	\$ 308,602	\$ 9,990	\$ 11,458	\$ (43)	\$ 209	\$ 4	\$ 10			\$ 4,922	\$ 4	\$ 268,676	\$ 603,833		
P36106	UPS Battery/Capacitor Fitness	General Plant					\$ 1,768	\$ (35)						\$ 1,733			
P36108	Bdmn-CCR Landfill Wells/SWStruct	Steam Production		\$ 148,816										\$ 148,816			
P36109	Distribution Automation	General Plant		\$ 14,633	\$ 31,845	\$ 20,906	\$ 48,840	\$ 107,704	\$ 41,782	\$ 319,577	\$ 357,232	\$ 174,672	\$ 548,565	\$ 1,665,755			
P36116	Wind Generation Fitness Program	Other Production	\$ 209,611	\$ 4,644	\$ 942,013	\$ 25,664	\$ 2,773	\$ 217,435	\$ 601,411	\$ 780,353	\$ 291,309	\$ 33,062	\$ 1,740,458	\$ 1,070,698	\$ 5,919,432		
P36117	PW: HP Feedwater Cntrl Valve Replac	Other Production					\$ 278,245	\$ 1,327	\$ (75)	\$ (19)	\$ (59)	\$ 22	\$ 38	\$ 279,479			
P36119	PN: Reconstruct Shoulder PN Dam Rd	Hydro Production					\$ 690,720	\$ 4,099	\$ 483	\$ 433	\$ 113	\$ 134	\$ 695,983				
P36122	Performance & Reliability Software	Intangible Plant	\$ 7,636	\$ 4,508	\$ (109,671)	\$ 9,091	\$ 142,097	\$ 6,486	\$ 2,640	\$ 49,549	\$ 27,900	\$ 1,002	\$ 13,513	\$ 13,025	\$ 167,777		
P36129	Purchase Truck for PGE Parks	General Plant		\$ 33,601	\$ (1)	\$ 18,173	\$ 3,001	\$ 1	\$ (13)	\$ (1)	\$ (9)	\$ 6	\$ 7	\$ 54,765			
P36132	CS: CTG & STG Protective Relay Upgr	Other Production						\$ 1,674,047	\$ 1,152	\$ (1,859)	\$ 779	\$ 918	\$ 1,675,036				
P36137	BR: Upgrade Boiler Feed Pump VSDs	Other Production	\$ 34,265	\$ (642)	\$ (28)	\$ 91	\$ (6)	\$ (2)	\$ 8,642					\$ 42,318			
P36145	Downtown Reach - DSL Easements	Distribution Plant	\$ -	\$ 250			\$ 1,250	\$ 985			\$ -	\$ 28,441	\$ 1,000	\$ 31,926			
P36166	Orient sub: Capacity Addition	Distribution Plant						\$ 19,509	\$ 2,151	\$ (1)	\$ 22,890	\$ 60,203	\$ 22,188	\$ 126,938			
P36167	FY: Repower Faraday Units 1-5	Hydro Production		\$ 1,133,224	\$ (1,187)	\$ (624)	\$ 46	\$ 268	\$ (312)	\$ (120)	\$ (229)	\$ -	\$ -	\$ 1,131,066			
P36169	PW - Purchase GT Rotor	Other Production	\$ 22,813											\$ 22,813			
P36170	OHSU Infrastructure Upgrades	Distribution Plant	\$ 2,187	\$ 3,005	\$ 5,303	\$ (185)	\$ 3,922	\$ 349	\$ 105	\$ 1,861	\$ (16)	\$ 539	\$ 947,234	\$ 69,830	\$ 1,034,135		
P36180	Purchase SDPM Field Vehicles	General Plant		\$ 25,820	\$ 797	\$ 938	\$ 10,783	\$ 2	\$ 561	\$ (8)	\$ 298,903	\$ 70,180	\$ 61,296	\$ 7,161	\$ 476,432		
P36187	Construct RPM Center	Other Production	\$ 464	\$ 633	\$ (14)	\$ (13)	\$ 103	\$ (2)	\$ 2	\$ 73				\$ 1,247			
P36189	PACE HR	Intangible Plant	\$ 19,367	\$ 22,931	\$ 23,612	\$ 14,136	\$ 14,762	\$ 504,671	\$ 19,406	\$ (392)	\$ (140)	\$ (272)	\$ 110	\$ 307	\$ 618,498		
P36190	PACE Finance- Supply Chain	Intangible Plant	\$ 46,625	\$ 19,479	\$ 10,833	\$ 17,913	\$ 7,968							\$ 102,818			
P36192	PACE Governance	Intangible Plant					\$ 487,023	\$ 9,484	\$ (273)	\$ (98)	\$ (190)	\$ 77	\$ 214	\$ 496,237			
P36193	Energy Network Redesign	General Plant	\$ (138,518)	\$ 26,885	\$ (46,331)	\$ 34,298	\$ 32,662	\$ 36,921	\$ 6,290	\$ 35,518	\$ 20,519	\$ 2,099	\$ 27,370	\$ 1,259	\$ 38,972		
P36195	PACE - Finance - Financials	Intangible Plant					\$ 337,636	\$ 87,296	\$ 48,445	\$ (124)	\$ 26,030	\$ 16,558	\$ 11,804	\$ 527,645			
P36205	Metal Streetlight Grounding	Distribution Plant						\$ 9,758	\$ 40,380	\$ 320,339	\$ 215,863	\$ (1,467)	\$ 584,873				
P36208	Mt. Scott Comm Tower Upgrade	General Plant	\$ 48,201											\$ 48,201			
P36213	Upgrade UG Streetlight Circuits	Distribution Plant	\$ 32,450	\$ 9,114										\$ 41,564			
P36214	Grand Ronde-Substation Interconnect	Distribution Plant					\$ 118,961	\$ (86)	\$ (151)	\$ 53	\$ 496	\$ 106	\$ 22	\$ 119,401			
P36215	Purchase Compact Track Loader	General Plant		\$ 67,808										\$ 67,808			
P36220	Wind: Install AGC equipment for EIM	Other Production					\$ 103,657	\$ 133	\$ 11	\$ (46)	\$ 68,128	\$ 116	\$ -	\$ 171,998			
P36222	Legacy Tool Replacement Project	General Plant		\$ 928,505	\$ 1,596	\$ 2,507	\$ 134,409	\$ 39,198	\$ 19,927	\$ 3,791	\$ 31,885	\$ 17,862	\$ -	\$ 1,179,681			
P36224	Replace ITIM	General Plant						\$ 14,016	\$ 1,516	\$ 4,341	\$ 4,192	\$ 7,114	\$ 31,179				
P36225	Comm-Purchase Mobile Radio Tower	General Plant	\$ 1,137	\$ 53	\$ 278	\$ 7,608	\$ 1,451	\$ 64	\$ (58)	\$ (53)	\$ 16	\$ (33)	\$ 31	\$ 12	\$ 10,506		
P36227	Kelly Creek Culvert Replacement	Distribution Plant	\$ 919	\$ 24	\$ (66)	\$ (25)	\$ (12)	\$ (5)	\$ 5					\$ 841			
P36228	Generation Cyber Security NIDs	Other Production	\$ 363	\$ 31,928	\$ 73,966	\$ 481	\$ 22,630	\$ 23,208	\$ 3,034	\$ 9,340	\$ 41,130	\$ 357,050	\$ 44,470	\$ 8,276	\$ 615,877		

Funding Project System																
Number	Funding Project Description	Function	201701	201702	201703	201704	201705	201706	201707	201708	201709	201710	201711	201712	Grand Total	
P36229	McGill Sub Capacity Additions	Distribution Plant						\$	8,560	\$	3,842	\$	1,886	\$	180,719	\$
P36234	Install Storeroom Pole Bunkers	General Plant			\$	69,742	\$	34,281	\$	54,210	\$	-	\$	4,511	\$	185,177
P36235	Install Low OH Services Guarding	Distribution Plant	\$	161	\$	10,966	\$	75,103	\$	50,200	\$	47,586	\$	69,233	\$	423,669
P36239	Purchase SCADA Tech Van	General Plant		\$	63	\$	45,150	\$	1,236	\$	(11)	\$	8	\$	(7)	\$
P36246	Malin Physical Security Upgrades	Transmission Plant	\$	6,821	\$	(6,960)	\$	-								(139)
P36251	Shute WJ2 Switchgear	Distribution Plant	\$	121,264	\$	383,623	\$	5,897	\$	15,110	\$	8,852	\$	(1,602,801)	\$	308,769
P36255	Substation-Purchase SF Cart	General Plant				\$	189,991	\$	239				280	\$	1,071,636	\$
P36257	2017 Purchase Corporate Furniture	General Plant				\$	103,605		\$	52,640	\$	11,966	\$	18,917		202,817
P36260	2017 Facilities Capital Fitness	General Plant					\$	29,303	\$	23,351	\$	297,529		\$	173,418	\$
P36280	Purchase Mobile Transformers	Distribution Plant			\$	2,171,423	\$	9,236	\$	2,169,343	\$	2,530	\$	199,405	\$	9,035,084
P36283	Comm Tech Dept - Buy Test Equipment	General Plant			\$	33,244			\$	29,434	\$	58		(0)	\$	160,720
P36284	2017 Server Fitness	General Plant	\$	13,777	\$	157,414	\$	203,757	\$	184,231	\$	2,222,395	\$	844,743	\$	6,345,224
P36285	T&D - Capital Tools & Lab Equipment	General Plant	\$	181	\$	583	\$	21,691	\$	136	\$	12,298	\$	213,536	\$	403,329
P36286	2017 Network Fitness	General Plant	\$	11,045	\$	981,767	\$	608,930	\$	525,855	\$	196,675	\$	200,093	\$	4,349,369
P36287	2017 Cyber Security Fitness	General Plant	\$	21,758			\$	34,251	\$	3,573	\$	125,818	\$	38,113	\$	354,339
P36288	2017 Desktop Fitness	General Plant	\$	388,638	\$	273,240	\$	474,074	\$	535,548	\$	256,012	\$	180,508	\$	4,210,833
P36292	CS: Upgrade Compressor to allow Fog	Other Production						\$	685,638	\$	23		(32)	\$	(10)	\$
P36305	BC - Replace Climb Assist	Other Production					\$	3,373	\$	110	\$	220,607	\$	12,980	\$	387,651
P36306	BR: Purchase GT Capital Spares	Other Production		\$	138,727	\$	232,760	\$	412,925	\$	58,965	\$	28,132			\$
P36307	PRP - Vehicles & Capital Equipment	General Plant	\$	35,691	\$	45,450	\$	168,779	\$	149,875	\$	122,565	\$	88,567	\$	1,438,536
P36311	PSES - Generation Fitness Fund	General Plant	\$	-							\$	79,056	\$	19,105	\$	98,160
P36325	Install Datapower Devices	General Plant	\$	322,779	\$	6,812	\$	4,685	\$	5,038	\$	4,089	\$	5,836	\$	350,563
P36326	Install Datapower Devices	Intangible Plant	\$	-							\$	159	\$	1,053,935	\$	1,621,098
P36330	Carty - Purchase Vehicles and Lifts	General Plant	\$	2,810	\$	15,595	\$	641	\$	9,496	\$	705	\$	(3)	\$	29,230
P36340	PowerPlan Upgrade & Lease Module	Intangible Plant					\$	850,455	\$	205,727	\$	6,406	\$	20,994	\$	1,099,169
P36351	Purchase Splicer Trailer	General Plant							\$	29,203	\$	45	\$	(4)	\$	29,390
P36353	NF: Install Fish Ladder Pumps	Hydro Production									\$	996,473	\$	(1,063)	\$	1,036,344
P36357	Purchase OSIsoft Licenses	General Plant								\$	15,450	\$	-	\$	(15,450)	\$
P36358	Purchase IT Storage for Critical Sy	General Plant		\$	2,142	\$	46,198	\$	172,494	\$	2,031,587	\$	23,851	\$	51,452	\$
P36360	TCC Skylight Replacements	General Plant								\$	93,278			\$	93,278	
P36365	CY: Complete Carty As-Built	Other Production			\$	40,998	\$	2,224	\$	121,218	\$	205,179	\$	77,312	\$	475,678
P36367	ELS Trailer for PRB Biologists	General Plant				\$	3,119									\$
P36371	CIP Low Impact Security Substations	General Plant							\$	3,854				\$	2,388	\$
P36383	Replace Gresham Entry Stairs	General Plant							\$	64,286	\$	221,486	\$	(198,428)	\$	87,350
P36393	McLoughlin Storage Yard Expansion	Distribution Plant							\$	886,912	\$	5,158	\$	(94)	\$	919,765
P36407	Automate Development Operations	General Plant						\$	198,069							\$
P36409	RM: Upgrade Attraction Water Pumps	Hydro Production									\$	253,150	\$	(79)	\$	258,307
P36488	Furniture - Staff Growth (TDRI)	General Plant									\$	65,315				\$
P19344	Underperforming Feeders	Distribution Plant											\$	608	\$	608
P21342	HR PeopleSoft Migration	General Plant											\$	-	\$	-
P22722	Pelton/Round Butte PME - Recreation	Intangible Plant											\$	-	\$	-
P22723	Pelton/Round Butte PME - Aquatic Re	Hydro Production											\$	-	\$	-
P26959	Communications Vintage and Growth	General Plant										\$	25,917	\$	-	\$
P35139	Facilities Fitness	General Plant										\$	987	\$	-	\$
P35200	Build Combined Back-Up Facility	General Plant										\$	(2,398)	\$	-	\$
P35459	Virtual Desktop Infrastructure	General Plant										\$	-	\$	-	\$
P35487	Oswego-West PtId 115kV Reconnector	Distribution Plant										\$	18	\$	-	\$
P35684	Web Fitness- Rmv Self Svc Barriers	Intangible Plant										\$	-	\$	3,720	\$
P35859	1WTC03 Floor Upgrade	General Plant										\$	-	\$	110	\$
P35873	Certificate Management Phase II	Intangible Plant										\$	-	\$	-	\$
P35933	Kelley Point Pad-Switch Replacement	Distribution Plant										\$	-	\$	10,859	\$
P35938	Field Voice Communications System	General Plant										\$	-	\$	-	\$
P35939	Replace KB Line Heater at Beaver	Other Production										\$	-	\$	-	\$
P35975	Substation Interconnection Const	General Plant										\$	-	\$	-	\$
P36005	Spectrum - 700mhz	Intangible Plant										\$	-	\$	5,938,311	\$
P36044	3WTCPL Upgrade	General Plant										\$	3,631	\$	10,035	\$
P36133	WSH: Upgrade Comm. Infrastructure	General Plant										\$	-	\$	-	\$
P36138	PW2 Add Blackstart Capability	Transmission Plant										\$	-	\$	-	\$
P36146	Energy Market Readiness Project	Intangible Plant									\$	10,209,457	\$	1,257,922	\$	1,135,940
P36179	EMS Upgrades for EIM	Intangible Plant										\$	631,023	\$	768,004	\$
P36218	Upgrade 3WTCBR Control Room	General Plant										\$	-	\$	-	\$
P36223	Replace Primary Cables Ronler Acres	Distribution Plant										\$	-	\$	-	\$

Funding Project

System																
Number	Funding Project Description	Function	201701	201702	201703	201704	201705	201706	201707	201708	201709	201710	201711	201712	Grand Total	
P36236	Purchase laptops/monitors - FASuite	General Plant										\$ -	\$ 42,680	\$ -	\$ 42,680	
P36252	Sunset WR2 DGA Monitor	Distribution Plant										\$ -	\$ -	\$ 117,915	\$ 117,915	
P36262	Newberg Traffic Signal Modification	General Plant										\$ -	\$ -	\$ 328,764	\$ 328,764	
P36271	OG: Timothy Spillway Modifications	Hydro Production										\$ 1,236,845	\$ 2,816	\$ 396,503	\$ 1,636,164	
P36273	Replace Glendoveer-Gresham 115kV	Distribution Plant										\$ 2,893,084	\$ 549,502	\$ 173,111	\$ 3,615,697	
P36276	Workplace EV Charging Phase 2	General Plant										\$ 467	\$ 1	\$ 17,655	\$ 18,122	
P36290	BR: Replace second VFD for BFP	Other Production										\$ -	\$ -	\$ 365,155	\$ 365,155	
P36293	BR - Replace Steam Turbine ETD	Other Production										\$ 363,898	\$ 34,254	\$ 212,928	\$ 611,080	
P36301	SN: Throat Liner Unit 13	Hydro Production										\$ 1,124,588	\$ 72,635	\$ 11,605	\$ 1,208,829	
P36338	BR: Unit 8 Repair	Other Production										\$ -	\$ -	\$ 2,634,947	\$ 2,634,947	
P36339	PSC Transformer Shop Enclosure	General Plant										\$ -	\$ -	\$ 357,862	\$ 357,862	
P36354	Spectrum - 200mhz	Intangible Plant										\$ -	\$ -	\$ 1,992,070	\$ 1,992,070	
P36370	IVR Development Environment	Intangible Plant										\$ -	\$ -	\$ 313,903	\$ 313,903	
P36373	Blue Lake Phase II	Distribution Plant										\$ 15,100	\$ 40,715	\$ -	\$ 55,815	
P36403	Build Sheep Solar Interconnect	Distribution Plant										\$ -	\$ 2,941	\$ 12,944	\$ 15,885	
P36412	Incremental Added Vehicles	General Plant										\$ -	\$ -	\$ 27,173	\$ 27,173	
P36415	PACE - Enterprise Data Warehouse	Intangible Plant										\$ -	\$ -	\$ 867,949	\$ 867,949	
P36451	CY: Upgrade Heat Trace System	Other Production										\$ -	\$ -	\$ 503,996	\$ 503,996	
P36454	Substation Rerock - multiple sites	Distribution Plant										\$ 340,541	\$ 379,315	\$ 967,562	\$ 1,687,418	
P36487	PGE Safety - Vehicle for Generation	General Plant										\$ -	\$ -	\$ 27,173	\$ 27,173	
P36489	T&D Application Reliability Imprvmt	General Plant										\$ 759	\$ 6,623	\$ 655	\$ 8,037	
P36490	Build WTC Integrated Sec Ops Ctr	General Plant										\$ 9,461	\$ 108,696	\$ 158,350	\$ 276,507	
P36498	Silverton West Feeder Reconductor	Distribution Plant										\$ -	\$ -	\$ 143,153	\$ 143,153	
P36506	Customer Touchpoints infrastructure	General Plant										\$ -	\$ -	\$ 708,112	\$ 708,112	
Grand Total			\$ 20,618,021	\$ 16,623,340	\$ 39,806,938	\$ 17,828,836	\$ 29,543,701	\$ 30,450,121	\$ 26,601,408	\$ 38,173,411	\$ 38,589,246	\$ 51,036,117	\$ 52,012,593	\$ 74,411,270	\$ 435,320,051	

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 107
Dated May 4, 2018**

Request:

Reference PGE's response to AWEC data request 26, project P35619 (the "Oracle Project"):

- a) Is this project the entirety of the amounts for the Customer Information System (CIS) and Meter Data Management System (MDMS) described in PGE/900?**
- b) Please provide the monthly CWIP balances associated with this project, for each month prior to being transferred to plant.**
- c) Has the referenced project been placed into service? If yes please identify the go live date, along with the total amount of capital transferred to plant. If no, please provide the latest estimate on when the Oracle Project will be completed, as well as the latest estimate of total capital costs.**
- d) Please identify the gross plant of PGE's existing billing system, meter data management systems, and any other systems that will be obsolete as a result of completing the Oracle Project.**

Response:

- a) P35619, CET Install Oracle CC&B/MDM Systems, is the entirety of the amounts for the Customer Information System (CIS) and Meter Data Management System (MDMS) described in PGE Exhibit 900, Section III. Attachment 107-A provides the project description and justification.
- b) Attachment 107-B provides monthly CWIP Balances May 2015-April 2018.
- c) Project P35619 in total is expected to be completed in Q3 2018. The replacement of the legacy CIS and MDMS are the major components of the project (Customer Touchpoints), and those two went live on May 14th, 2018. The amount initially transferred to plant, exclusive of trailing capital costs, will be known when the May books are closed. There project will incur additional capital costs during the stabilization months following the May 14th go live. The estimate of total capital costs is \$153,942,650.

- d) Attachment 107-C provides capitalized costs and software programs replaced by the installation of the Oracle CIS and MDMS. All of these costs have been fully amortized as of year-end 2017. PGE amortizes software using either a 5-year life or a 10-year life.

May 18, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 108
Dated May 4, 2018**

Request:

Reference PGE's response to AWEC data request 26, project P35679 (the "Marquam Project"):

- a) Please provide a narrative description of this project**
- b) Please provide monthly CWIP balances associated with the Marquam Project.**
- c) Please provide the latest estimate on when the Marquam Project will be completed, as well the latest estimate of total capital costs.**

Response:

- a) The Marquam Project includes a new 115kV state-of-the-art substation and two feeders to: (1) increase capacity due to growth in the South Waterfront area and (2) replace aging infrastructure nearing the end of its service life in downtown Portland. The substation contains gas insulated switchgear that allows us to fit the project within the small size of the property footprint. A new 115kV transmission line is constructed inside the Tilikum Crossing Bridge and continues underground into the Marquam Substation. Two ¾-mile long underground distribution feeders run from the substation to downtown Portland on Naito Pkwy and 1st Ave.
- b) Attachment 108-A provides monthly CWIP Balances for P35679, Construct Marquam Project, through April 2018.
- c) The Marquam Substation was completed and went in service in April 2018. The overall Marquam project is expected to be completed in Q2 2019. The latest estimate of total capital costs for the Marquam project is \$82,929,785.

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 116
Dated May 15, 2018**

Request:

Reference PGE's Response to AWEC DR No. 083, Attachment 083-A CONF:

- a. Please provide the context behind the referenced power point slide and provide a copy of the entire presentation.**
- b. Does PGE's rate case capital forecast include the project changes described as "\$6.6 million in funding to cover 5-week go-live delay and reestablish project contingency funding."?**

Response:

- a. Attachment 116-A provides the complete presentation from which the slide was obtained. The slide is also in PGE's response to OPUC Data Request No. 270, part (t). The presentation was at a Finance Committee Meeting on April 24, 2018. The Finance Committee meets on a regular basis to review project budgets and scope. They are provided with regular updates on various aspects of projects including status of budget, issues, risk, and timeline updates. Attachment 116-A is protected information and subject to Protective Order 18-047.
- b. PGE's rate case capital forecast does not include the described project changes. PGE's deferral filing for Customer Touchpoints (UM 1948) includes this additional capital amount.

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 120
Dated May 15, 2018**

Request:

Reference FERC Account 407.0001, Amort Of UnrecvPlt-Troj Decomm:

- a. Please explain how PGE developed the amortization forecast for this account in the test period.**
- b. Please provide workpapers for the forecasted amortization of \$2,500,000 in the test period, along with the forecasted amortization and balance calculations through the life of the decommissioning trust.**

Response:

- a) PGE updated the Trojan model for the latest Trojan Nuclear Decommissioning Trust (NDT) balances, expected rate of return on trust assets, cost estimates, and other parameters. Please see all the update actions performed by PGE in the "Model Update Actions" tab in the Trojan model provided as Attachment 120-A.
- b) Attachment 120-A provides the work papers included in the Trojan model. Please note that to model a zero dollar balance of the Trojan NDT in 2034,¹ PGE would have to set the Trojan annual accrual at approximately \$1.8 million. However, because PGE is currently in the process of renewing our Nuclear Regulatory Commission license at Trojan for an additional 40 years, which will add considerable uncertainty associated with the spent nuclear fuel at the Trojan site, PGE proposes at this time an annual accrual of \$2.5 million.

Attachment 120-A is protected information subject to Protective Order No. 18-047.

¹ The year that is currently modeled for the Trojan nuclear decommissioning completion.

May 24, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 121
Dated May 15, 2018**

Request:

Reference PGE/200 workpaper “Exhibit Support 2019_Tax Plan”, Tab “Rate Base Data” Incentives Adjustment (UE 283 - \$10 Million over 20 Years). Please identify the line item where the corresponding amortization of this regulatory liability has been reflected in operating results, and provide detail to demonstrate that the amortization has been included.

Response:

PGE inadvertently did not include the amortization entry in its initially filed UE 335 revenue requirement. PGE will, however, include a \$500,000 adjustment to reduce amortization expense as part of its next revenue requirement update in the UE 335 proceeding.

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 122
Dated May 15, 2018**

Request:

Reference PGE/200 workpaper, “Exhibit Support 2019_Tax Plan, Tab “Rate Base Data,” “Dispatchable Generation.” Please identify the order where the Dispatchable Generation regulatory asset was approved and provide workpapers supporting the balance and the amount that PGE proposes to amortize to rates in this matter.

Response:

PGE’s Dispatchable Standby Generation (DSG) program pays participating customers owning large, diesel-powered generators for fuel and routine maintenance costs in exchange for access to generator output during times when the PGE grid needs extra power. The DSG program began in the late 1990s as a research and development initiative. Page 11 of the Public Utility Commission of Oregon Order No. 01-777 (Docket No. UE 115) approved and acknowledged PGE’s DSG program.

Internally approved and built DSG projects have been included in PGE’s rate base through our general rate case process. PGE reports various statistical information about each DSG facility on pages 410/411 FERC Form 1, Generating Plant Statistics (Small Plants). Over time, PGE is incorporating DSG projects as part of the integrated resources plan (IRP) goals (i.e. 2014 IRP).

Attachment 122-A provides the Dispatchable Standby Generation year-end 2018 forecast. Attachment 122-A is protected information and subject to Protective Order No. 18-047

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 123
Dated May 15, 2018**

Request:

Reference PGE/200 workpaper, “Exhibit Support 2019_Tax Plan” Tab “A&G”:

- a. Please provide a description of the following three items included on the referenced tab: Revolver Fees, Margin Net Interest, Broker Fees.
- b. Please provide the historical amounts paid with respect to Revolver Fees, Margin Net Interest, Broker Fees over the period 2015, 2016, and 2017.
- c. Please describe the accounting treatment of costs associated with Revolver Fees, Margin Net Interest, Broker Fees for both book and tax accounting purposes.
- d. Please identify all legal fees paid with respect to issuing stock over the period 2015, 2016, and 2017, and identify the FERC account to which the responsive legal fees were booked.
- e. Please identify all legal fees forecast to be paid with respect to issuing stock in the test period.

Response:

- a. **Revolver Fees:** Fees paid to the bank to have access to a revolving line of credit facility. Revolver fees include Revolver Extension Fees, Annual Fees, and agent and legal fees.

The line of credit is used to ensure that the company has access to adequate short term liquidity.

Margin Net Interest: Interest paid to trading counter parties for deposits held as collateral for energy, capacity, transmission, and fuel purchase contracts.

Broker Fees: Fees paid to third party brokers for arranging or locating trades for PGE’s merchant organization as well as fees from clearing brokers and exchanges that facilitate trades of energy, capacity, transmission, and fuel related commodities.

b.

Year	2015	2016	2017
Revolver Fees	\$917,153	\$917,153	\$917,153

Year	2015	2016	2017
Margin; Net Interest	\$284,141	\$435,070	\$266,161

Year	2015	2016	2017
Broker Fees	\$297,816	\$522,042	\$399,990

- c. **Revolver Fees:** Fees are paid and charged to FERC account 186. The fees are amortized over the life of the credit facility and charged to FERC account 431. There is no difference for book and tax purposes.

Broker Fees and Margin Net Interest: Costs associated with broker fees are expensed as part of Administrative and General Expenses. The entry would be to debit expense and credit cash. However, activity related to a clearing broker, including margin net interest expense, will be credited against a margin broker deposit account rather than cash. Margin net interest income is recorded as a credit to Interest Income and a debit to broker margin deposits.

- d. PGE did not issue any stock in 2017 and 2016; therefore no legal fees were incurred in those years. In Q2 of 2015, the company issued 10,400,000 shares of common stock. PGE did not incur legal fees in 2015 with respect to issuing stock because the 2015 stock issuance was tied to an Equity Forward Sales Agreement (EFSA) that was executed in conjunction with a prior stock issuance in 2013. Due to the EFSA being in place, PGE did not incur any additional legal fees in 2015.
- e. We do not anticipate any legal fees will be allocated to stock issuance in the test year as we are not anticipating any new issuance of authorized shares.

May 24, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 126
Dated May 15, 2018**

Request:

Please provide the revenue requirement workpapers used to calculate the final stipulated revenue requirement in Docket UE 319.

Response:

Attachment 126-A provides the requested information.

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 129
Dated May 15, 2018

Request:

Reference PGE's response to AWEC Data Request 27, UE 335_AWEC DR 027_Attach A CONF, Project P35980:

- a. Please state the total number of PCB transformers on the Company's system that have been replaced pursuant to this project as of 12/31/2017.**
- b. Please identify the total number of PCB transformers that PGE still needs to replace for this project.**
- c. Please provide a narrative explaining the overall status of this project.**

Response:

- a) 2,683 PCB transformers have been replaced as of December 31, 2017.
- b) PGE is testing transformers to identify those that need to be replaced. This testing process runs in a parallel process with the replacement of transformers. The current estimate is that there are 6,400 transformers requiring replacement. This is an estimate based upon the current rate of PCB's identified as present in existing transformers.
- c) Attachment 129-A provides the up-to-date Funding Project justification for the PCB project P35980 providing discussion, status, and alternatives considered for this project. Testing is planned to be completed in 2020 with replacements of identified transformers completed by year-end 2021.

Attachment 129-A is protected information subject to Protective Order 18-047.

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 131
Dated May 15, 2018**

Request:

Reference PGE's response to AWEC Data Request 27, UE 335_AWEC DR 027_Attach A CONF, Project P35938:

- a. Please provide all internal project justification documentation and presentations with respect to the referenced project, including any benefits studies that were prepared when making the decision to proceed with this project.**
- b. Please state the total amount of capital that has been placed in service for this project, since work on the project was initiated.**
- c. Please provide all change orders that have been submitted with respect to the referenced project.**

Response:

PGE objects to this request on the basis that is overly broad and unduly burdensome. Without waiving its objection, PGE responds as follows:

- a) Attachment 131-A provides the up-to-date funding project P35938 justification form including project scope, timeline, expected benefits, and project revisions. Also, please see Attachment 131-B for an update presentation provided to PGE's board of directors on February 15, 2017. In addition, PGE will be providing an enterprise communication update in a workshop with stakeholders on June 28, 2018.
- b) Total amount of capital that has been placed in service for P35938, Field Voice Communication System, is \$12,740,824 as of April 30, 2018. Attachment 131-C, cell G4, provides the total amount that closed to plant by month since December 2017.
- c) Attachment 131-A provides all project revisions since the project started in 2014.

Attachments 131-A and 131-B are protected information subject to Protective Order No. 18-047.

May 31, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 133
Dated May 15, 2018**

Request:

**Reference PGE's response to AWEC Data Request 27, UE 335_AWEC DR 027_Attach A
CONF, Project P22449:**

- a. Please provide any cost-benefit analyses that PGE has performed to justify making such investments with respect to the referenced project.
- b. Please identify the Gross Plant balance for Colstrip Units 3 and 4, forecast for December 31, 2018.
- c. Please identify the Accumulated Depreciation balance for Colstrip Units 3 and 4, forecast for December 31, 2018.
- d. Please identify the Accumulated Deferred Income Tax balance for Colstrip Units 3 and 4, forecast for December 31, 2018.
- e. Please identify the Excess Accumulated Deferred Income Taxes balance for Colstrip Units 3 and 4, forecast for December 31, 2018.
- f. Please identify the Fuel Stock balance for Colstrip Units 3 and 4, forecast for December 31, 2018.
- g. Please identify the amount of Operating Expenses for Colstrip Units 3 and 4, forecast in the test period.
- h. Please identify the amount of Taxes Other Than Income Taxes for Colstrip Units 3 and 4, forecast in the test period.

Response:

- a) PGE's 20% ownership stake in the Colstrip power plant includes the annual review of the capital and O&M spend with the plant's operator, Talen Energy. PGE's operating agreement with Talen allows for Talen to determine annually what capital work is required to operate the plant safely and reliably within its environmental permitting requirements through its planned operating lifetime. These projects are reviewed with the co-owners prior to annual approval of the site budget.

Specifically, during the annual review of capital in the July and August timeframe, Colstrip capital projects¹ are each discussed with justifications explained to the co-owners by the plant operator in the session noted above. These justifications fall into a number of categories including:

- Regulatory (REG)
- Environmental (ENV)
- Discretionary (DIS)
- Technical (TECH)
- Other (OTR)

For the 2018 capital budget planning year, the only investments in capital are REG, ENV, and OTR. Roughly 60% of the capital budget was allocated to ENV and REG requirements the plant site operator must meet to enable proper operation and decommissioning activities for the facility under its operating license and permits. The balance of the capital expenditures (OTR) is related to overhauls and equipment replacement to ensure safe and reliable operation of plant equipment within its operational license period and currently planned end of life timeline. No investments are being made to increase performance or asset life beyond the currently stated plant operational lifetime.

- b) Attachment 133-A provides PGE's estimated gross plant balance for the Colstrip Plant at December 31, 2018.
- c) Attachment 133-B provides PGE's estimated depreciation reserve balance for the Colstrip Plant at December 31, 2018.
- d) The Accumulated Deferred Income Tax balance for Colstrip Units 3 and 4 forecasted for December 31, 2018 is \$25 million. This includes the protected deferred balances after tax reform.
- e) The Excess Accumulated Deferred Income Taxes Balance for Colstrip Units 3 and 4 forecasted for December 31, 2018 is \$8 million.
- f) PGE forecasts the Fuel Stock balance for year-end 2018 to be \$3,421,000.
- g) PGE forecasts the operating expenses for the 2019 test year to be \$22,973,567.
- h) The following are Colstrip related taxes other than income taxes:
 - Account 4081003, Property Tax Montana: \$5,316,372
 - Account 4081014, Miscellaneous Taxes and Licenses Montana: \$432,504 (includes Montana Electrical Energy License Tax)

¹ Referenced in the Project P22449 Justification provided in PGE's response to AWEC Data Request No. 027, Attachment 027-A.

- Account 4081014, Transmission Operation – Transportation of Electricity by Others: \$2,412,348 (includes the Beneficial Use Tax for the BPA transmission lines in Montana that is part of PGE's Net Variable Power Cost).

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 worksheet “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.**

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.

PLANT BALANCE ROLLFORWARD FOR FORECASTED 2018

func_class_id	Data							
	1/1/2018 0:00				2/1/2018 0:00			
	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance
Distribution Plant	\$ 3,534,502,816	\$ 10,391,995	\$ (2,432,652)	\$ 3,542,462,158	\$ 3,542,462,158	\$ 15,345,989	\$ (2,432,652)	\$ 3,555,375,495
General Plant	\$ 550,582,628	\$ 6,773,604	\$ (5,006,619)	\$ 552,349,613	\$ 552,349,613	\$ 14,750,424	\$ (5,006,619)	\$ 562,093,418
Hydro Production	\$ 532,712,715	\$ 107,903	\$ (76,127)	\$ 532,744,491	\$ 532,744,491	\$ 134,986	\$ (76,127)	\$ 532,803,350
Intangible Plant	\$ 606,786,784	\$ 3,526	\$ -	\$ 606,790,310	\$ 606,790,310	\$ 3,526	\$ -	\$ 606,793,836
Other Production	\$ 2,901,961,539	\$ 77,719	\$ -	\$ 2,902,039,258	\$ 2,902,039,258	\$ 250,225	\$ -	\$ 2,902,289,483
Steam Production	\$ 971,591,865	\$ 29,855	\$ (164,805)	\$ 971,456,916	\$ 971,456,916	\$ 29,921	\$ (164,805)	\$ 971,322,032
Transmission Plant	\$ 547,410,320	\$ 50,512	\$ (239,286)	\$ 547,221,546	\$ 547,221,546	\$ 53,393	\$ (239,286)	\$ 547,035,652
Grand Total	\$ 9,645,548,668	\$ 17,435,114	\$ (7,919,489)	\$ 9,655,064,293	\$ 9,655,064,293	\$ 30,568,463	\$ (7,919,489)	\$ 9,677,713,267

Plant Balance Excludes Carty Incremental costs

func_class_id	3/1/2018 0:00				4/1/2018 0:00			
	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance
Distribution Plant	\$ 3,555,375,495	\$ 14,011,338	\$ (2,432,652)	\$ 3,566,954,181	\$ 3,566,954,181	\$ 60,424,227	\$ (2,432,652)	\$ 3,624,945,756
General Plant	\$ 562,093,418	\$ 6,871,864	\$ (5,006,620)	\$ 563,958,662	\$ 563,958,662	\$ 13,449,826	\$ (5,006,619)	\$ 572,401,869
Hydro Production	\$ 532,803,350	\$ 167,136	\$ (76,127)	\$ 532,894,360	\$ 532,894,360	\$ 192,218	\$ (76,127)	\$ 533,010,450
Intangible Plant	\$ 606,793,836	\$ 2,121,898	\$ -	\$ 608,915,734	\$ 608,915,734	\$ 140,003,526	\$ -	\$ 748,919,260
Other Production	\$ 2,902,289,483	\$ 1,586,986	\$ -	\$ 2,903,876,469	\$ 2,903,876,469	\$ 3,499,261	\$ -	\$ 2,907,375,731
Steam Production	\$ 971,322,032	\$ 2,550,201	\$ (164,805)	\$ 973,707,429	\$ 973,707,429	\$ 30,707	\$ (164,805)	\$ 973,573,331
Transmission Plant	\$ 547,035,652	\$ 185,670	\$ (239,286)	\$ 546,982,036	\$ 546,982,036	\$ 15,550,316	\$ (239,286)	\$ 562,293,066
Grand Total	\$ 9,677,713,267	\$ 27,495,093	\$ (7,919,490)	\$ 9,697,288,871	\$ 9,697,288,871	\$ 233,150,081	\$ (7,919,488)	\$ 9,922,519,463

Plant Balance Exclu

func_class_id	5/1/2018 0:00				6/1/2018 0:00			
	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance
Distribution Plant	\$ 3,624,945,756	\$ 16,310,294	\$ (2,432,652)	\$ 3,638,823,399	\$ 3,638,823,399	\$ 29,435,616	\$ (2,432,652)	\$ 3,665,826,363
General Plant	\$ 572,401,869	\$ 4,122,017	\$ (5,006,620)	\$ 571,517,266	\$ 571,517,266	\$ 4,915,904	\$ (5,006,619)	\$ 571,426,551
Hydro Production	\$ 533,010,450	\$ 100,030	\$ (76,127)	\$ 533,034,353	\$ 533,034,353	\$ 2,556,718	\$ (76,127)	\$ 535,514,944
Intangible Plant	\$ 748,919,260	\$ 1,561,778	\$ -	\$ 750,481,038	\$ 750,481,038	\$ 6,605,102	\$ -	\$ 757,086,139
Other Production	\$ 2,907,375,731	\$ 2,666,632	\$ -	\$ 2,910,042,363	\$ 2,910,042,363	\$ 1,271,590	\$ -	\$ 2,911,313,952
Steam Production	\$ 973,573,331	\$ 30,707	\$ (164,805)	\$ 973,439,234	\$ 973,439,234	\$ 2,530,707	\$ (164,805)	\$ 975,805,136
Transmission Plant	\$ 562,293,066	\$ 52,415	\$ (239,286)	\$ 562,106,195	\$ 562,106,195	\$ 897,232	\$ (239,286)	\$ 562,764,141
Grand Total	\$ 9,922,519,463	\$ 24,843,873	\$ (7,919,490)	\$ 9,939,443,846	\$ 9,939,443,846	\$ 48,212,868	\$ (7,919,488)	\$ 9,979,737,226

Plant Balance Exclu

func_class_id	7/1/2018 0:00				8/1/2018 0:00			
	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance
Distribution Plant	\$ 3,665,826,363	\$ 17,157,279	\$ (2,432,652)	\$ 3,680,550,989	\$ 3,680,550,989	\$ 13,804,764	\$ (2,432,652)	\$ 3,691,923,102
General Plant	\$ 571,426,551	\$ 8,719,646	\$ (5,006,620)	\$ 575,139,577	\$ 575,139,577	\$ 4,969,186	\$ (5,006,618)	\$ 575,102,145
Hydro Production	\$ 535,514,944	\$ 350,307	\$ (76,127)	\$ 535,789,125	\$ 535,789,125	\$ 1,382,216	\$ (76,127)	\$ 537,095,214
Intangible Plant	\$ 757,086,139	\$ 166,382	\$ -	\$ 757,252,521	\$ 757,252,521	\$ 6,382	\$ -	\$ 757,258,903
Other Production	\$ 2,911,313,952	\$ 570,445	\$ -	\$ 2,911,884,398	\$ 2,911,884,398	\$ 451,509	\$ -	\$ 2,912,335,907
Steam Production	\$ 975,805,136	\$ 46,146	\$ (164,805)	\$ 975,686,477	\$ 975,686,477	\$ 37,107	\$ (164,805)	\$ 975,558,780
Transmission Plant	\$ 562,764,141	\$ 114,627	\$ (239,286)	\$ 562,639,481	\$ 562,639,481	\$ 1,522,194	\$ (239,286)	\$ 563,922,389
Grand Total	\$ 9,979,737,226	\$ 27,124,832	\$ (7,919,490)	\$ 9,998,942,568	\$ 9,998,942,568	\$ 22,173,359	\$ (7,919,488)	\$ 10,013,196,439

Plant Balance Exclu

func_class_id	9/1/2018 0:00				10/1/2018 0:00			
	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance
Distribution Plant	\$ 3,691,923,102	\$ 20,732,606	\$ (2,432,652)	\$ 3,710,223,055	\$ 3,710,223,055	\$ 17,006,897	\$ (2,432,652)	\$ 3,724,797,300
General Plant	\$ 575,102,145	\$ 12,821,683	\$ (5,006,620)	\$ 582,917,208	\$ 582,917,208	\$ 4,933,519	\$ (5,006,618)	\$ 582,844,109
Hydro Production	\$ 537,095,214	\$ 1,273,523	\$ (76,127)	\$ 538,292,610	\$ 538,292,610	\$ 122,653	\$ (76,127)	\$ 538,339,136
Intangible Plant	\$ 757,258,903	\$ 54,668	\$ -	\$ 757,313,571	\$ 757,313,571	\$ 787,069	\$ -	\$ 758,100,640
Other Production	\$ 2,912,335,907	\$ 1,670,695	\$ -	\$ 2,914,006,601	\$ 2,914,006,601	\$ 2,415,434	\$ -	\$ 2,916,422,036
Steam Production	\$ 975,558,780	\$ 2,552,549	\$ (164,805)	\$ 977,946,524	\$ 977,946,524	\$ 139,056	\$ (164,805)	\$ 977,920,775
Transmission Plant	\$ 563,922,389	\$ 3,034,595	\$ (239,286)	\$ 566,717,697	\$ 566,717,697	\$ 971,420	\$ (239,286)	\$ 567,449,831
Grand Total	\$ 10,013,196,439	\$ 42,140,318	\$ (7,919,490)	\$ 10,047,417,267	\$ 10,047,417,267	\$ 26,376,047	\$ (7,919,488)	\$ 10,065,873,826

Plant Balance Exclu

	11/1/2018 0:00				12/1/2018 0:00			
func_class_id	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance	Sum of begin_balance	Sum of additions	Sum of retirements	Sum of end_balance
Distribution Plant	\$ 3,724,797,300	\$ 10,275,679	\$ (2,432,652)	\$ 3,732,640,327	\$ 3,732,640,327	\$ 58,490,280	\$ (2,432,652)	\$ 3,788,697,955
General Plant	\$ 582,844,109	\$ 3,887,472	\$ (5,006,620)	\$ 581,724,960	\$ 581,724,960	\$ 19,312,209	\$ (5,006,618)	\$ 596,030,551
Hydro Production	\$ 538,339,136	\$ 8,321,729	\$ (76,127)	\$ 546,584,738	\$ 546,584,738	\$ 15,506,373	\$ (76,127)	\$ 562,014,984
Intangible Plant	\$ 758,100,640	\$ 9,911	\$ -	\$ 758,110,551	\$ 758,110,551	\$ 20,012,459	\$ -	\$ 778,123,010
Other Production	\$ 2,916,422,036	\$ 3,333,674	\$ -	\$ 2,919,755,710	\$ 2,919,755,710	\$ 7,025,634	\$ -	\$ 2,926,781,344
Steam Production	\$ 977,920,775	\$ 29,331	\$ (164,805)	\$ 977,785,302	\$ 977,785,302	\$ 3,019,860	\$ (164,805)	\$ 980,640,357
Transmission Plant	\$ 567,449,831	\$ 2,096,141	\$ (239,286)	\$ 569,306,685	\$ 569,306,685	\$ 22,479,225	\$ (239,286)	\$ 591,546,623
Grand Total	\$ 10,065,873,826	\$ 27,953,937	\$ (7,919,490)	\$ 10,085,908,273	\$ 10,085,908,273	\$ 145,846,041	\$ (7,919,488)	\$ 10,223,834,826

Plant Balance Exclu

	Total Sum of additions		Total Sum of retirements	
func_class_id				
Distribution Plant	\$	283,386,963	\$	(29,191,824)
General Plant	\$	105,527,354	\$	(60,079,431)
Hydro Production	\$	30,215,791	\$	(913,522)
Intangible Plant	\$	171,336,226	\$	-
Other Production	\$	24,819,805	\$	-
Steam Production	\$	11,026,148	\$	(1,977,656)
Transmission Plant	\$	47,007,739	\$	(2,871,436)
Grand Total	\$	673,320,026	\$	(95,033,868)

Plant Balance Exclu

UE 335

(REDACTED VERSION)

Exhibit AWEC/206 contains Protected Information and has been redacted in its entirety in accordance with Order No. 18-047.

**BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON
UE 335**

)
In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
_____)

**OPENING RATE CASE TESTIMONY OF
DR. MARC M. HELLMAN
ON BEHALF OF THE ALLIANCE OF WESTERN ENERGY CONSUMERS**

June 6, 2018

**TABLE OF CONTENTS TO THE
OPENING RATE CASE TESTIMONY OF DR. MARC M. HELLMAN**

I. INTRODUCTION AND SUMMARY	1
II. FTE	4
III. BENEFITS	15
IV. INCENTIVES	18
V. PENSIONS	23
VI. ENERGY SUPPLIER ASSESSMENT	25
VII. NON-REVENUE REQUIREMENT ISSUE AND RECOMMENDATION	30

EXHIBIT LIST

Exhibit AWEC/301: Qualification Statement of Dr. Marc Hellman

Confidential Exhibit AWEC/302: Budget Manual Instructions for 2016 and 2017

Exhibit AWEC/303: OLS Output Results for Comparable Company Analysis

Confidential Exhibit AWEC/304 PGE Benefits Ranking

Confidential Exhibit AWEC/305: PGE Incentive Program Examples

Exhibit AWEC/306: Average to Budget Incentives Percentage Payout

Exhibit AWEC/307: PGE Responses to Data Requests

Exhibit AWEC/308: Central Lincoln People's Utility Dist. v. Oregon Dept. of
Energy, Marion County Cir. Ct. Case No. 16CV18269
(Aug. 9, 2017)

Exhibit AWEC/309: Excerpt of ODOE ESA PowerPoint

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Dr. Marc Hellman. My business address is 2760 Eagle Eye Ave. NW, Salem, Oregon 97304.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant and an economist by training with significant experience in energy utility regulation. I am testifying on behalf of the Alliance of Western Energy Consumers ("AWEC").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a Masters and PhD in Economics awarded by Claremont Graduate School and a Bachelor's degree in both Economics and Mathematics awarded by California State Polytechnic University, Pomona.

With regards to my work experience, I was employed for 38 years in various capacities by the Public Utility Commission of Oregon, with the last twenty years or so in a management capacity leading economists, accountants and financial analysts in the review of utility general rate filings and rate proposals, financing and affiliated interest applications, property sales, and mergers and acquisitions. I have also worked for Boeing Computer Services and the Bonneville Power Administration. More recently, I have also provided consulting services, with my most recent projects for the Commonwealth Utilities Corporation with headquarters in Saipan, the Smart Energy Alliance in a Nevada

1 Power general rate filing before the Public Utilities Commission of Nevada, and the
2 South Dakota Intrastate Pipeline Company.

3 I provide a listing of my education and experience in Exhibit AWEC/301.

4 **Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?**

5 A. The purpose of this testimony is to review Portland General Electric Company's ("PGE"
6 or "Company") general rate case application, docketed as UE 335, with respect to FTE,
7 wages and salaries, benefits, incentives, pension, and the energy supplier assessment.

8 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

9 A. I recommend the Commission reduce PGE's wage-related costs related to personnel by
10 an amount of \$16,445,653. This recommendation is based on adjustments to projected
11 FTE levels and wages and salaries associated with those levels. The reduction of FTE is
12 from PGE's test-year amount of 2867.5 to 2700, which equals a reduction of 167.5 FTE.
13 Using the PGE average dollars-per-FTE of \$98,183, and multiplying that number by the
14 167.5 reduction in FTE, the dollar reduction in wages is \$16,445,653.

15 With respect to medical benefits, I recommend a reduction in expense of
16 \$12,940,730. This reduction is based on taking the 2017 PGE actual benefits per FTE
17 cost, reducing it by five percent, and then escalating that value by 6.5 percent for two
18 years to derive a 2019 dollars per FTE value of \$32,436. Including a reduction in FTE of
19 167.5 yields a total reduction in benefits cost of \$12,940,730.

20 My incentives adjustment is \$3,313,393. This amount recognizes that the PGE
21 incentives are contingent on sufficient earnings and therefore I increase, including other
22 adjustments, the disallowance that PGE has assumed. The adjustment reflects the fact

that PGE does not always pay its incentives in the amount budgeted. PGE over the most recent six-year history on average has paid 91 percent of budgeted incentives for non-officers. Another adjustment reflects removing 100 percent of the Board compensation paid in stock, which acts as an incentive to the Board to increase PGE share price. Finally, my adjustment of \$3,313,393 incorporates the derived incentive-per-FTE amount of \$3,597 multiplied by the 167.5 reduction in FTE, totaling \$602,498.

I recommend pension expense be reduced by \$2,500,000, reflecting increases in the discount rate from when PGE prepared its testimony. My recommendation is based on a 30-basis point increase in the discount rate.

Finally, I recommend a disallowance of \$2,068,281, which represents the amount PGE has included in the test year related to the Energy Supplier Assessment (“ESA”). This is based on my assessment that PGE acted imprudently in failing to join litigation challenging the ESA for the 2017-2019 fiscal biennium and the lack of evidence demonstrating that customers receive any benefits from the ESA.

Q. DO YOU HAVE A SUMMARY TABLE DISPLAYING THESE RECOMMENDATIONS?

A. Yes. Table 1, below, summarizes my recommendations.

TABLE 1

<u>Topic</u>	<u>Adjustment Amount</u>
FTE	\$16,445,653
Benefits	\$12,940,730
Incentives	\$3,313,393
Pensions	\$2,500,000
ESA	\$2,068,281
Total	\$37,268,393

1 **Q. DO THE VALUES ABOVE REFLECT REVENUE REQUIREMENT VALUES?**

2 A. No. For the compensation-related adjustments, those values still need to be split between
3 capital and expense in order to derive revenue requirement values. The revenue
4 requirement impact of my adjustments is provided in Table 1 of the Opening Rate Case
5 Testimony of Bradley G. Mullins, Exhibit AWEC/200, and in Mr. Mullins' revenue
6 requirement calculations in Exhibit AWEC/201.

7 **Q. DO YOU HAVE ANY NON-REVENUE REQUIREMENT**
8 **RECOMMENDATIONS?**

9 A. Yes. I recommend the Commission direct PGE to file a report with the Commission no
10 later than six months following the Commission's final order in this docket. The report
11 would investigate changing PGE's budgeting approach to dollars instead of FTEs as
12 suggested in Exhibit PGE/400, Mersereau-Neitzke/17-18, along with providing historical
13 data for all labor-related services inclusive of contracted-for and PGE labor resources.

14 **II. FTE**

15 **Q. PLEASE DESCRIBE PGE'S FTE RECOMMENDATIONS.**

16 A. In PGE's testimony, Exhibit PGE/400, Mersereau-Neitzke, PGE provides a forecast of
17 2019 Test Year FTEs. The source data for Table 2, below, is from the PGE/400
18 testimony and is used to calculate an average wage per FTE.

1

TABLE 2

	FTE			Wages			Wages Per FTE		
	2017 Actuals	2018 Budget	2019 Test Year	2017 Actuals	2018 Budget	2019 Test Year	2017 Actuals	2018 Budget	2019 Test Year
PGE									
Administrative & General	372.1	402.9	389.4	\$73,980	\$79,464	\$77,984	\$198,818	\$197,230	\$200,267
Information Technology	304.3	332.8	306.7	\$26,678	\$25,548	\$26,881	\$87,670	\$76,767	\$87,646
Customer Service	464.5	451.9	455.1	\$7,240	\$8,309	\$8,609	\$15,587	\$18,387	\$18,917
Generation	548.7	558.8	562.2	\$54,307	\$54,192	\$56,639	\$98,974	\$96,979	\$100,745
Transmission and Distribution	1044.9	1153.0	1154.1	\$98,485	\$107,560	\$111,427	\$94,253	\$93,287	\$96,549
Total	2734.6	2899.4	2867.5	\$260,690	\$275,073	\$281,540	\$95,334	\$94,872	\$98,183

2 The average wage per FTE for 2019 is \$98,183.

3 **Q. BEFORE GOING FURTHER, DOES PGE HAVE STRONG REGULATORY**
4 **INCENTIVES TO CONTROL ITS REQUESTS FOR WAGE EXPENSE?**

5 A. No. The exception that clearly comes to mind is where there are standard regulatory
6 practices of disallowances, such as there are with incentives. In that case, PGE does have
7 the incentive to control costs as shareholders bear all (as with officers) or a portion (as
8 with non-officers) of the costs.

9 However, with many of the areas of operation, PGE has the incentive to overstate
10 its prospective costs. Once rates are established, absent some sharing mechanism without
11 a dead-band, PGE then has the incentive to control its costs since every dollar of cost
12 cutting goes to shareholders. When using historic test periods, without adjusting for
13 known and measurable changes, the utility does have the incentive to control costs
14 because of regulatory lag. When costs increase, the utility does not get to recover those
15 costs on a prospective basis until they have been reflected in a rate case.

1 Also, with historic test periods, there is actual data from which to review. The
2 utility has the incentive to ensure its costs are prudent as the Commission likely has the
3 policy of removing costs from the test year that are not prudent.

4 **Q. I NOTICED THAT YOU HAVE DISCUSSED HISTORICAL TEST PERIODS,**
5 **BUT THE OREGON PUC TYPICALLY USES A FUTURE TEST PERIOD.**
6 **DOES A UTILITY HAVE AS STRONG AN INCENTIVE TO CONTROL ITS**
7 **COSTS WITH A FUTURE TEST YEAR?**

8 A. I do not believe so. The reason is the lack of regulatory lag. The utility can project its
9 costs and has the opportunity to recover those costs in full under a future test period as
10 there is no regulatory lag.

11 **Q. IS THERE A DRAWBACK TO A FUTURE TEST PERIOD?**

12 A. Yes. Future test periods are typically forecasted in some fashion and there is discretion
13 and a subjective element to the forecast. One could argue that the utility has the upper
14 hand in this discretion as it has more information typically than do outside analysts, so
15 there is asymmetric information. For example, the utility can identify all areas of
16 operation where costs are increasing and leave it to the outside analyst to identify areas
17 where costs are decreasing.

18 **Q. WHILE PERHAPS NOT HAVING A STRONG INCENTIVE, DOES A UTILITY**
19 **HAVE THE INCENTIVE TO CONTROL ITS COSTS AT ALL UNDER A**
20 **FUTURE TEST PERIOD FORMAT?**

21 A. Yes. Once a utility has its rates set, the utility has the incentive to control its costs.
22 However, this incentive is diminished during a period of frequent rate case filings.

23 **Q. WHY IS THAT?**

24 A. A utility with frequent rate cases has the incentive to build up its costs during these rate
25 cases, with future test periods. It is likely not a successful strategy to overstate future test

1 year costs, have actual costs come in lower, and expect the regulator to not figure out that
2 costs are consistently being forecasted too high. However, building up on an upward
3 trending cost basis and having actual costs come in at those levels will establish a “high”
4 level of costs that are recovered through rates. At some point, when the utility believes it
5 will not need to file a rate case for a few years, the utility could control its costs and any
6 cost savings would go to shareholders. Management in a utility may also want to build
7 up a larger and larger company so as to justify higher compensation as well.

8 Again, in both historic and future test periods, the utility does have some
9 incentive to control its costs. The discussion here posits that the incentive is stronger in a
10 historic test year rate setting framework because of greater regulatory lag.

11 **Q. PLEASE DISCUSS YOUR ANALYSIS OF PGE’S FTE TESTIMONY AND**
12 **RECOMMENDATIONS.**

13 A. In this Docket, as in UE 319, PGE again projects significant increases in FTE levels as
14 compared to calendar year 2017. As noted in AWEC’s (then ICNU) testimony in
15 UE 319, having growth in employees faster than Company fundamentals in the long term
16 is not sustainable, as it places upward pressures on rates.^{1/}

17 From an economics perspective, the PGE case is curious. Traditional economics
18 provides that capital and labor are substitutes. You can use a mix of capital and labor to
19 produce products. When wages are relatively high, which they are in the United States,
20 capital substitutes for labor such as using equipment to trim trees or read meters. For the
21 last several years, however, PGE has made investments in both capital (information and
22 technology investments for example) and labor (increases in FTE), leading to increases in

^{1/} Docket No. UE 319, Exhibit ICNU/300, Mullins/10-11.

rates. Presumably, all else held equal, major investments in technology should lead to decreases in labor, but overall that has not been the case, as evidenced by PGE's general rate case filing, and this result raises questions about the prudence of PGE's capital spending.

Q. WHAT IS THE PGE PROJECTED INCREASE IN LOADS AND CUSTOMERS FROM 2017 TO 2019?

A. PGE's response to AWEC Data Request 93 includes the following total load and customer information from which that question can be answered.^{2/}

Year	Total Customers	Load	FTE
2017 (Actual)	874568	1601	2734.6
2019 (PGE Requested or Projected)	895433	1587	2867.5
Percentage Increase	2.39	-0.87	4.86

The last column is taken from FTE totals listed in Exhibit PGE/400, Mersereau-Neitzke/13. Notice that the requested number of FTE grows twice as fast as total customers. With respect to load, load is declining and yet FTEs grow significantly.

Q. PGE HAS PROVIDED TESTIMONY THAT DISCUSSES CHANGES IN FTE AND THE FUNDAMENTAL CAUSES REQUIRING THOSE CHANGES. DO YOU FIND THAT TESTIMONY CONVINCING?

A. No, not on a total-Company basis. PGE may be identifying trends in certain areas of the Company, but the key assumption in PGE's testimony is essentially that everything else not discussed in PGE's testimony relating to FTE and workload is being held constant.

^{2/} Exhibit AWEC/307, Hellman/13-22.

1 **Q. WHAT DO YOU MEAN?**

2 A. One way to analyze the PGE FTE request is to review all the new position descriptions to
3 see if the positions look necessary to handle the work requirements. But let us say that
4 was done and all the requested positions look needed. That by itself does not mean that
5 PGE's FTEs should increase by that amount. In mathematical terms, it would be deemed
6 necessary but not sufficient.

7 **Q. WHY IS THAT?**

8 A. The information that is lacking from PGE's testimony is essentially a critical review of
9 all PGE positions. This is because work load in some areas may not be needed, or as
10 critical, or some positions could be combined to capture efficiencies in work product.
11 Management should be expected to take this critical review to manage costs. Therefore,
12 in my opinion, PGE has not satisfied its burden to demonstrate a need for its requested
13 increase in FTEs.

14 For non-economically regulated companies, competitive pressures can drive a
15 company to evaluate its labor needs in order to control costs so that its prices are
16 competitive and also produce a reasonable return to shareholders. Regulated utilities
17 such as PGE do not face such pressures.

18 **Q. DID YOU REVIEW THE BUDGETING REVIEW PROCESS TO SEE IF PGE**
19 **HAD UNDERTAKEN A FULL REVIEW OF ITS FTE POSITIONS?**

20 A. I reviewed the Company's budget instruction manuals for 2017 and 2018, which are
21 attached as Confidential Exhibit AWEC/302. The manual for the 2019 budget is not
22 available as those are developed in the third quarter of 2018. In reviewing the manuals,

1 they seemed designed more from an accounting perspective, ensuring common
2 definitions and accounting recording across agencies.

3 **Q. DID YOU SEE ANYTHING IN THE BUDGET INSTRUCTION MANUALS**
4 **ASKING FOR A REVIEW OF COST AND PROGRAMS TO IDENTIFY**
5 **EFFICIENCIES OR REVIEW EXISTING PROGRAM LEVELS?**
6

7 A. No.

8 **Q. DID YOU CONDUCT ANY ANALYSIS TO DETERMINE OVERALL**
9 **REASONABLENESS OF PGE FTE LEVELS?**

10 A. Yes. I noticed that in last year's ICNU testimony there was presented a comparison with
11 Puget Sound Energy ("Puget") and what Puget's operating relationships implied for
12 PGE.^{3/} I also reviewed PGE's responsive testimony that viewed Puget as not a
13 reasonable proxy for PGE, as Puget is a combined electric/natural gas utility. Given that
14 discussion in UE 319, I analyzed FTE relationships using several other energy utilities.

15 **Q. PLEASE DESCRIBE THE APPROACH YOU UNDERTOOK.**

16 A. In PGE's cost of capital testimony, PGE identifies utility/energy companies of
17 comparable risks. The list of companies is found on Exhibit PGE/1003, Hager-Liddle-
18 Villadsen/3.

19 For the listed companies, I researched the following information: number of
20 employees, number of customers, number of transmission line miles, and number of
21 distribution line miles. I was able to find that information for many of the companies
22 listed in PGE/1003, Hager-Liddle-Villadsen/3.

23 My next step was to estimate, using ordinary least squares regression, the
24 relationship of number of company employees to the factors listed above. In addition, I

^{3/} Docket No. UE 319, Exhibit ICNU/300, Mullins/11.

used a distribution line miles per customer as a possible explanatory variable, as a compact utility might have different labor needs than a utility with customers spread out. Table 3, below, provides the relevant data:

TABLE 3

	Employees	Customers	Trans. Lines Miles	Distrib. Lines Miles	Distrib. Line Miles Per Customer
AEP Ohio	1551	1472771	8195	45718	0.0310422
AEP Texas	1623	972853	8736	42691	0.0438823
AEP Appalachian Power	1986	1040204	7434	54284	0.0521859
Indiana Michigan Power	2368	587252	5240	20410	0.0347551
Kentucky Power	635	167708	1283	10080	0.0601045
Public Service Company of Oklahoma	1671	550000	3635	22260	0.0404727
Southwestern Electric Power Company	1716	534632	4103	25197	0.0471296
Center Point Energy	7727	2403340	3718	52639	0.0219024
Idaho Power Company	1964	547000	4857	27441	0.0501664
Duke Energy	28798	7483171	32300	268700	0.0359072
OGE Energy	2500	830057	5200	55500	0.0668629
Ameren	8500	3300000	4500	67500	0.0204545

Q. HOW DID YOU PERFORM YOUR ANALYSIS OF THE INFORMATION IN THE TABLE ABOVE?

A. I ran two ordinary least squares regression analyses, the output for which I have attached as Exhibit AWEC/303. The first regression used all the data in the above table. Using the relationships estimated using ordinary least squares, and applying them to PGE's number of customers, transmission line miles, distribution line miles and distribution line miles per customer, PGE would have 2,137 FTE.^{4/} However, in this regression, none of

^{4/} Exhibit AWEC/303, Hellman/1.

the estimated coefficients are significant in “t value”.^{5/}

The second regression was identical in formulation to the first with the exception that I excluded the last variable, namely the distribution line miles per customer. Using this formulation, the number of PGE FTE would be 2,185, applying the estimated parameters to PGE’s data.^{6/} In the second regression, the coefficient to the first two variables—the intercept term and number of customers—is significant.

The results for both of the regressions are close to one another, being less than 50 FTE apart. I also note that the fitted PGE FTE values are several hundred FTE lower than PGE’s current FTE level.

Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. I conclude that the Commission should be very hesitant to approve rates based on a significant increase in PGE FTE levels.

Q. DID YOU ALSO DEVELOP ANY SUGGESTED PGE FTE LEVELS BY LOOKING AT PGE’S RECENT CUSTOMER AND LOAD GROWTHS IDENTIFIED EARLIER IN YOUR TESTIMONY?

A. Yes. The information is in Table 4, below.

TABLE 4

Year	Total Customers	Load	FTE Using Average Growth	PGE Projected FTE
2017	874568	1601	2734.6	2734.6
2019	895433	1587	2755.2	2867.5
Percentage Increase	2.39%	-0.87%	0.76%	4.86%

^{5/} A “t” statistic determines the existence of a significant correlation between variables and follows a “t” distribution. See page 791, “Introductory Econometrics”, Wooldridge, Thomson, 2006.

^{6/} Exhibit AWEC/303, Hellman/2.

1 PGE had 2734.6 FTE in 2017. Using the average of the growth rate for total
2 customers and load produces a 2019 FTE level of 2755.2. Even if you only used the
3 customer growth rate of 2.39 percent by itself, the resulting FTE level is 2800, still
4 significantly below PGE's FTE request of 2867.5. I show the last column on the right to
5 display the growth in FTE PGE is requesting in this docket as a comparison.

6 **Q. SHOULD THE COMMISSION GIVE MUCH WEIGHT TO THE 2755 OR 2800**
7 **FTE VALUES USING THE MOST RECENT FTE AND CUSTOMER GROWTH**
8 **RATE VALUES?**

9 A. No. The reason is that the 2017 value by itself reflects a major increase in number of
10 FTE from prior years. If we do the same analysis looking at the growth in customers
11 from 2016 to 2019, instead of 2017 to 2019, we get significantly different results.

12 **Q. PLEASE EXPLAIN.**

13 A. In 2016, the actual FTEs were 2581.3 and number of customers were 862,764.^{7/} The
14 percentage change in customers from 2016 to 2019 is 3.79%. If you increase the 2016
15 actual FTEs of 2581.3 by the 3.79% you get a 2019 FTE level of 2679. Table 5, below,
16 displays this information.

^{7/} Docket No. UE 319, PGE/400, Mersereau-Jaramillo/11; Exhibit AWEC/307, Hellman/20 (PGE Resp. to AWEC Data Request 93, Attach. 93-D).

1

TABLE 5

	UE 319 2016 Actuals	UE 335 2017 Actuals	UE 319 2018 Test Year	UE 335 2018 Budget	UE 335 2019 Test Year
PGE FTEs	2581.3	2734.5	2851.0	2899.4	2867.5
Number of Customers	862764				895433
Growth from 2019 to 2019					3.79%
FTE at Comparable Growth					2679.0

2

Looking at the 2016 to 2019 growth rate in customers could support an FTE level

3

of 2679.

4

**Q. BASED ON ALL OF YOUR ANALYSES ABOVE, WHAT IS YOUR
RECOMMENDED FTE LEVEL THAT SHOULD BE USED IN THIS DOCKET?**

5

6

A. I recommend the Commission base rates on 2700 FTE. This represents a 167.5 reduction
in the PGE UE 335 requested FTE level. This takes into account the discussion above by
placing more weight on the longer-term relationship of customer growth and FTE.

7

8

9

**Q. HAS THE COMMISSION DISCUSSED THE MERITS OF USING A LONGER-
TERM TREND OF FTE IN AN ORDER?**

10

11

A. Yes. In Docket UE 102, OPUC Staff had proposed using several years (1991 through
1999) to form a trend for establishing a recommended level of FTE. PGE opposed the
Staff trending analysis as not being statistically well founded. The Commission in Order
99-033 adopted Staff's approach, however, stating that this approach was "likely to
produce consistent reasonable figures. We adopt Staff's principle."^{8/}

12

13

14

15

^{8/} Re: Portland General Electric Company, Docket No. UE 102, Order No. 99-033, 1999 WL 135188 (Or.P.U.C.), 191 P.U.R.4th 87 at *56 (Jan. 27, 1999).

Q. WHAT DOES THIS PROVIDE FOR AN ADJUSTMENT TO PGE'S 2019 WAGE EXPENSE LEVEL?

A. Using PGE's 2019 wage and salary levels of \$98,183 per FTE, and reducing the number of FTE by 167.5, yields an adjustment of \$16,445,653.

III. BENEFITS

Q. PLEASE DISCUSS YOUR REVIEW OF BENEFITS.

A. For the benefits analysis I focused on information provided by PGE in its testimony and accompanying exhibits, one of which is marked confidential. Benefits cost will also depend on number of FTE, so the first step is to derive a recommended benefit per FTE, and then apply that to the FTE levels I am recommending.

Using that information, I develop an adjustment for benefits expense for 2019.

Table 6, below, shows this analysis for deriving a recommended benefits expense per FTE.

TABLE 6

	FTE ¹			Benefits ²			Benefits Per FTE		
	2017	2018	2019 Test Year	2017	2018	2019	2017	2018	2019
PGE	Actuals	Budget	Year	Actuals	Budget	Test Year	Actuals	Budget	Test Year
Total	2734.5	2899.4	2852.0 ^{9/}	\$82,318	\$96,502	\$100,519	\$30,103	\$33,283	\$35,245
Percentage Change From Prior Year		6.03%	-1.10%		17.23%	4.16%		10.56%	5.89%
Value if increased by 6.5%								\$32,060	\$34,144

¹ PGE/400, Mersereau-Neitzke/12

² PGE/400, Mersereau-Neitzke/28

^{9/} In response to AWEC Data Request 66, PGE stated that it assumed 2852 FTE for medical benefits. For purposes of how I calculate the adjustment, the number of FTE PGE projects does not impact my adjustment. I use actual 2017 benefits per FTE cost, and escalate that to 2019 values, and then apply the cost per FTE to my recommended 2019 FTE levels.

1 **Q. DOES YOUR ANALYSIS BEGIN WITH DEVELOPING A 2017 BENEFITS PER**
2 **FTE AMOUNT?**

3 A. Yes. That is the \$30,103 value shown in the table above.

4 **Q. PLEASE EXPLAIN THE ROW TITLED, “VALUE IF INCREASED BY 6.5%.”**

5 A. I included that line as Exhibit PGE/400, Mersereau-Neitzke/29, line 17, says that
6 nationally the projected growth rate for medical costs is 6.5 percent. I use that national
7 average to escalate the growth in actual 2017 PGE benefits cost to project 2018 and 2019
8 values.

9 **Q. WHAT DOES THIS IMPLY FOR AN ADJUSTMENT TO BENEFITS?**

10 A. PGE has a test year benefits amount of \$100,519,000. If benefits are adjusted to \$34,272,
11 which is the 2017 actual value escalated two years at 6.5 percent, and you apply that
12 average benefit level to my recommended FTE level of 2700, you get a 2019 Test Year
13 benefits amount of \$92,534,223. Subtracting \$92,534,223 from \$100,519,000 yields a
14 reduction of benefits expense of \$7,984,777. This adjustment is inclusive of all costs
15 (such as administrative) for Total Benefits listed in Table 8, Exhibit PGE/400,
16 Mersereau-Nietzke/28.

17 **Q. SO IS YOUR RECOMMENDED ADJUSTMENT THEN THE \$7,984,777 VALUE?**

18 A. No. I have one more step in my derivation.

19 **Q. PLEASE EXPLAIN.**

20 A. In the beginning of Exhibit PGE/400, Mersereau-Nietzke/4, PGE discusses its total
21 compensation philosophy which includes “the features and costs both among employee

1 groups and against what other employers in our market provide to their employees.”^{10/}

2 To better understand what other companies provide to their employees, PGE retained
3 firms to do market studies comparing PGE to the industry with respect to benefits
4 compensation.

5 **Q. PLEASE CONTINUE.**

6 A. PGE testimony includes Confidential Exhibit/402 that provides two separate studies
7 ranking PGE compensation against other comparable companies. The studies show that
8 PGE is well above average and is in fact one standard deviation above that average. I
9 have included Confidential Exhibit AWEC/304, showing this result.

10 **Q. WHAT YEAR IS ANALYZED BY THE PGE-REQUESTED STUDIES?**

11 A. It appears that the studies are for 2017. That means that the 2017 actual level is above
12 the average and should be adjusted downward.

13 **Q. WHAT DOWNWARD ADJUSTMENT DO YOU MAKE?**

14 A. I recommend making a five percent adjustment. The five percent value comes from
15 looking at the results of the PGE confidential studies and conservatively inferring the
16 amount PGE is above market. With the five percent adjustment downwards, that moves
17 PGE much closer to market.

18 If we take the actual 2017 benefits per FTE, and reduce them by five percent, and
19 then escalate those values by 6.5 percent annually, we get a 2019 Test-Year benefits per
20 FTE amount of \$32,436, shown in Table 7, below.

^{10/} Exhibit PGE/400, Mersereau-Nietzke/27.

TABLE 7

Benefits Per FTE			
2017 Actual	2017 Adjusted	2018 at 6.5%	2019 at 6.5%
\$30,103	\$28,598	\$30,457	\$32,436

Q. SO WHAT IS YOUR RECOMMENDATION WITH RESPECT TO BENEFITS?

A. I recommend a reduction of \$12,940,730 to benefits expense be applied to PGE's test year request of \$100,519,000. That number is derived by applying the per-FTE medical benefits cost of \$32,436 shown in the table above to my recommended FTE level of 2700, for a total 2019 benefits cost of \$87,578,270.

IV. INCENTIVES

Q. PLEASE SUMMARIZE PGE'S REQUEST FOR INCENTIVES INCLUDED IN THE 2019 TEST YEAR.

A. PGE included a value of \$13,026,000 in its 2019 Test Year. This value is taken by calculating the estimated level of total 2019 incentives and then taking 50 percent of that value for all incentives except for PGE Officer incentives which PGE excluded 100 percent from the test year.

Q. WHY DID PGE EXCLUDE A PORTION OF THE PROJECTED INCENTIVES FROM ITS 2019 TEST YEAR REQUEST?

A. PGE states that they did so to reduce its overall revenue requirement request and that this is consistent with what PGE proposed in UE 319^{11/}.

^{11/} Exhibit PGE/400, Mersereau-Neitzke/21-22.

1 **Q. ARE THE PERCENTAGES PGE EXCLUDED CONSISTENT WITH**
2 **COMMISSION PRACTICE?**

3 A. Partially. PGE's 100 percent exclusion of officers' incentives is consistent with
4 Commission practice. However, the 50 percent exclusion of the other incentives is not
5 consistent with Commission practices.

6 **Q. WHY IS THAT?**

7 A. In its UE 319 testimony, Staff included a description of Commission policy with respect
8 to incentives.

For incentives, Commission policy traditionally disallows 100 percent of officers' bonuses, which are typically based on earnings. 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.^{12/}

9 Given that awarding the incentives is contingent on meeting an earnings threshold, PGE's
10 exclusion of 50 percent of the incentives, and not some greater percentage perhaps up to
11 75 percent, is not appropriate.

12 **Q. DID YOU REVIEW PGE'S INCENTIVES TO SEE WHETHER ANY OF THE**
13 **NON-OFFICER INCENTIVES SHOULD BE EXCLUDED AT THE 75 PERCENT**
14 **LEVEL INSTEAD OF AT 50 PERCENT?**

15 A. Yes. In reviewing PGE's incentives policies for non-officers, which are provided in
16 PGE's Workpapers, it appears that most of the incentives are dependent on PGE's
17 earnings being sufficient as a trigger as to whether the incentive is provided by PGE. It
18 also appears that whether an earnings level is sufficient is ultimately up to executive

^{12/} Docket No. UE 319, Exhibit Staff/400, Gardner/35-36.

1 management. However, the incentives are typically awarded on performance in areas
2 other than those tied directly to earnings. So while they are not “earnings” performance
3 incentives, granting incentives is dependent on earnings. I have attached as Confidential
4 Exhibit AWEC/305 two of PGE’s incentives programs.

5 This contrasts with an incentive mechanism that is independent of earnings. For
6 example, you could have an incentive awarded contingent solely on the number of at-
7 fault customer complaints being below a threshold. Presumably it is this kind of
8 incentive that would merit the 50 percent disallowance.

9 **Q. SO WHAT DO YOU CONCLUDE?**

10 A. I conclude that a modest further adjustment is warranted on this issue because earnings
11 are a factor (and sometimes a dispositive factor) as to whether the incentive is paid out.

12 **Q. WHAT ADJUSTMENT DO YOU RECOMMEND?**

13 A. For this topic, and consistent with Commission practice, I recommend an adjustment
14 between 50 and 75 percent. Specifically, I recommend 55 percent of the non-officer
15 incentives be excluded because a value greater than 50 percent is warranted. While it is
16 true that the incentives themselves are not directly tied to earnings, there has to be
17 sufficient earnings to enable the incentives to be granted, so they are earnings-related. A
18 movement of 50 to 55 percent seemed a reasonable and modest recognition of this fact.

19 **Q. IS THAT YOUR SOLE ADJUSTMENT APPROACH FOR INCENTIVES?**

20 A. No. There are other considerations in developing a recommended adjustment.

21 The first adjustment has to do with an overall adjustment to incentives levels. In
22 looking over the history of budgeted versus actual incentives, I noticed that on average

1 actual incentives paid out are less than budgeted incentives. In response to AWEC Data
2 Request 49, PGE provided a history of budgeted and actual incentives for 2012 through
3 2017 inclusive.^{13/} From that data, PGE's actual paid incentive was on average, for non-
4 officer and Board incentives over the most recent six years, 2012 through 2017, inclusive,
5 91 percent of budgeted. A copy of my spreadsheet analysis is attached as Exhibit
6 AWEC/306. I therefore took PGE's forecast for 2019 incentives and multiplied them by
7 91 percent to get an expected incentives paid estimate.

8 **Q. WHAT IS YOUR NEXT CONSIDERATION IN DEVELOPING YOUR**
9 **ADJUSTMENT?**

10 A. PGE includes compensation to the Board in the form of stock. I removed all of this cost.

11 **Q. WHY?**

12 A. While this may be viewed as "compensation in the form of wages" and not incentives, I
13 removed all the cost because as PGE's share price increases the value of the
14 compensation increases. It is an incentive to the Board members to increase PGE's share
15 price and therefore I consider it an incentive form of compensation. This is true even if
16 the amount of stock paid to the Board member is independent of PGE's earnings. I
17 should also note that in PGE's spreadsheet provided to AWEC in response to AWEC
18 Data Request 67, PGE labels the payment as "Board of Directors Stock Incentives."^{14/}
19 Because stock payments to the Board are properly viewed as incentives based on
20 earnings, they should be excluded from rates per established Commission policy.

^{13/} Exhibit AWEC/307, Hellman/6-7.

^{14/} Exhibit AWEC/307, Hellman/11.

1 **Q. SO WHAT DO YOU DERIVE AS YOUR ADJUSTMENT?**

2 A. To derive my adjustment, I calculate the amount of expected incentives that is includable
3 in rates per Commission policy. My analysis is based on using a 91 percent expected
4 payout of budgeted incentives, removing officer incentives, Board member stock
5 incentives, and removing 55 percent of non-officer incentives. This yields an incentive
6 expense of \$10,315,000. Since PGE has a 2019 Test Year expense of \$13,026,000, my
7 adjustment would be in the amount of \$2,711,000 for the factors described above. But
8 there is another factor to incorporate.

9 **Q. WHAT IS THE OTHER FACTOR TO INCORPORATE?**

10 A. PGE does not have to pay incentives on FTE that are not included in revenue
11 requirements. Since I am making an FTE adjustment, there should be an incentive
12 adjustment reflective of this. To do this calculation, we need to calculate a per-FTE
13 incentive. The incentive per FTE using my incentive amount above of \$10,315,000 is
14 \$3,597. This is calculated by taking the \$10,315,000 and dividing it by PGE's FTE value
15 of 2867.5. Taking the \$3,597 and multiplying that by my recommended FTE level of
16 2700 equals \$9,712,731. Subtracting \$9,712,731 from \$13,026,000 produces an
17 adjustment equal to \$3,313,393.

18 **Q. SO WHAT ARE YOUR RECOMMENDATIONS REGARDING INCENTIVES?**

19 A. I recommend an adjustment of \$3,313,393.

V. PENSIONS

Q. PLEASE DISCUSS YOUR REVIEW OF PENSION EXPENSE.

A. As noted in Exhibit PGE/400, Mersereau-Nietzke/34, PGE has identified \$21.5 million in pension costs for 2019 with \$14.5 million after capitalization. That same testimony on page 35 states that PGE used a discount rate of 3.64 percent. Further on in the testimony on that same page, PGE notes that interest rates will likely change and PGE will submit a revised discount rate in September.

Q. DO YOU SUPPORT PGE'S REQUEST TO UPDATE THE DISCOUNT RATE IN SEPTEMBER?

A. No. I believe it is preferable to determine the discount rate as we do most other matters being reviewed in the rate case. I know of no compelling argument as to why to single out this issue for updating. I understand that interest rates change over time, and that may benefit or harm consumers, but this is no different from many other assumptions in a rate case. The more inputs PGE is allowed to update over the course of its case, the less risk it has relative to other utilities, which would argue in favor of a reduction to its return on equity to account for this lower risk.

Instead, given PGE's and market consensus expectations that interest rates will continue to rise in 2018-2019, PGE should have reflected this expectation in its pension cost assumptions in its initial filing.

Q. WHAT KIND OF SECURITIES ARE USED TO BASE THE DISCOUNT RATE UPON?

A. On Exhibit PGE/400, Mersereau-Nietzke/35, they state that high grade AA-rated corporate bonds are used.

Q. DO PENSION COSTS VARY AS THE DISCOUNT RATE CHANGES?

A. Yes. As the discount rate increases, pension costs decrease as future obligations are discounted at a higher rate. In response to AWEC Data Request 73, a copy of which is included within Exhibit AWEC/307, PGE states that a 10-basis point increase in the discount rate reduces pension expense by \$860,000.

Q. WHAT IS A HIGH-GRADE AA CORPORATE BOND RATE RETURN AT THIS TIME OF PREPARING YOUR TESTIMONY?

A. According to the website <https://fred.stlouisfed.org/series/HQMCB30YRP>, the current bond rate is roughly 30 basis points higher, reflecting the increase in interest rates that has occurred over the last several months.



Q. GIVEN THIS INCREASE IN CORPORATE BONDS, DO YOU RECOMMEND AN ADJUSTMENT TO FAS 87 PENSION EXPENSE?

A. Yes. I recommend that pension expense be reduced by the impact of a 30-basis-point increase in the discount rate. My estimate of the change in FAS 87 expense is \$2,500,000. This is based on both PGE's response to AWEC Data Request 73, as well as

1 PGE's response to Standard Data Request 60. PGE's response to that data request,
2 included within Exhibit AWEC/307, provides that a 25-basis point increase in the
3 discount rate would decrease FAS 87 expense by \$2.1 million.

4 **VI. ENERGY SUPPLIER ASSESSMENT**

5 **Q. WHAT IS THE ENERGY SUPPLIER ASSESSMENT ("ESA")?**

6 A. The ESA is a statutory fee on all "energy resource suppliers." ORS 469.421(8) provides
7 the requirements of the ESA. Under this law, "energy resource suppliers" include "an
8 electric utility...supplying, generating, transmitting or distributing electricity...in
9 Oregon."^{15/} Thus, energy resource suppliers include all consumer- and investor-owned
10 electric utilities, including PGE. The ESA provides a general revenue source for ODOE
11 and also funds the Governor's Energy Policy Advisor.

12 **Q. HOW IS THE ESA AMOUNT DETERMINED?**

13 A. ORS 469.421(8)(b) sets forth the procedure for determining the assessment. ODOE's
14 Director ("Director") determines the aggregate amount of the ESA that will be collected
15 from energy suppliers to support the Energy Facility Siting Council and ODOE programs
16 and activities. After making that determination, the Director is required to convene a
17 public meeting with representatives of energy resource suppliers and other interested
18 parties in order to provide these suppliers with a "full accounting" of both the projected
19 revenue needed to fund each department program or activity and the projected allocation
20 of moneys derived from the assessment imposed.

^{15/} ORS 469.421(8)(i)(A).

1 **Q. DID ODOE FOLLOW THE PROPER PROCEDURE FOR ASSESSING THE ESA**
2 **FOR THE 2015-2017 BUDGET?**

3 A. No. In 2016, certain energy suppliers challenged ODOE's process. Specifically, these
4 energy suppliers, which did not include PGE, challenged whether the Director provided
5 the required "full accounting." The Marion County Circuit Court ruled on summary
6 judgment that there was "no genuine issue of material fact" that the Director did not
7 provide a "full accounting" because "ODOE failed to specifically provide the
8 representatives of energy resource suppliers and other interested parties the projected
9 revenue needed to fund each department program or activity and the projected allocation
10 of monies derived from the assessment imposed under this subsection to each department
11 program or activity."^{16/} ODOE is currently appealing the Court's ruling.

12 **Q. WHAT IS THE CALCULATED ESA FOR THE 2017-2019 BUDGET?**

13 A. The ODOE-calculated ESA is \$13,119,539.^{17/} PGE's share for the 2017-2018 fiscal year
14 is \$2,407,834.^{18/} Both the total ESA, and the portion allocated to PGE, represents the
15 latest in a series of significant ESA increases. Over the past five years, PGE's ESA has
16 increased by 75%.^{19/}

^{16/} Exh. AWEC/308, Hellman/7 (Central Lincoln People's Utility Dist. v. Oregon Dept. of Energy, Marion County Cir. Ct. Case No. 16CV18269 (Aug. 9, 2017)).

^{17/} Exh. AWEC/309 ("ARB ESA" column).

^{18/} Exh. AWEC/307, Hellman/1(PGE Resp. to ICNU DR 012). Certain data request in this exhibit are labeled "ICNU" because AWEC changed its name from the Industrial Customers of Northwest Utilities during the discovery phase of this proceeding.

^{19/} Id. at 5 (PGE Resp. to AWEC DR 038, Attach. 038-A).

1 **Q. DID ODOE PROVIDE A “FULL ACCOUNTING” TO ENERGY SUPPLIERS TO**
2 **JUSTIFY THE ESA FOR THE 2017-2019 BUDGET?**

3 A. No. ODOE’s accounting for ESA funds consisted of a single page spreadsheet in a larger
4 PowerPoint presentation that provides lump sum numbers in generalized categories.^{20/}
5 This appears to be the complete explanation ODOE provided for its use of the ESA for
6 the current fiscal biennium. As can be seen, no specific information is provided as to
7 why the collection or application of the ESA funding categories is appropriate or
8 necessary. For instance, over \$4 million of the ESA is allocated simply to the “Director’s
9 Office” without any further explanation.

10 **Q. DID ENERGY SUPPLIERS CHALLENGE THEIR ASSESSMENTS FOR THE**
11 **2017-2018 BUDGET YEAR BASED ON GROUNDS SIMILAR TO THOSE IN**
12 **THE 2016 LITIGATION?**

13 A. Yes. A much larger group challenged their assessments for this most recent fiscal year.
14 This action has been stayed pending the outcome of the appellate process for the 2016
15 litigation on the basis that the Court’s ruling would be the same. Again, PGE did not join
16 this litigation despite the high likelihood of success given the Court’s prior ruling. In
17 fact, only one investor-owned utility joined this litigation – Cascade Natural Gas.

18 **Q. DOES PGE RECOVER ITS ESA FROM CUSTOMERS?**

19 A. Yes, PGE has included \$2,068,281 in 2019 test year rates.^{21/}

^{20/} Exh. AWEC/309. The full PowerPoint is available at: <http://www.oregon.gov/energy/About-Us/Documents/2016%20ODOE%20Budget%20Webinar.pdf>.

^{21/} Exh. AWEC/307, Hellman/1 (PGE Resp. to ICNU DR 012).

1 **Q. HAS PGE EXPLAINED WHY IT DID NOT JOIN THE LITIGATION OVER THE**
2 **2017-2018 ESA?**

3 A. Yes. In response to ICNU Data Request 13, PGE explained it intended to support the
4 appeal of the 2016-2017 ESA, but did not join the lawsuit over the 2017-2018 ESA
5 because resolution of this litigation “will have no additional effect on the legitimacy or
6 legality of the ESA.”^{22/}

7 **Q. IS THIS A SATISFACTORY EXPLANATION?**

8 A. No. PGE’s response entirely ignores the primary purpose of joining the 2017-2018
9 litigation, which is to obtain a refund of the ESA for this fiscal year. While I am not a
10 lawyer, AWEC’s attorneys inform me that only the named plaintiffs in the litigation will
11 be entitled to such a refund if the litigation is successful.^{23/} Thus, by not joining the
12 2017-2018 litigation, PGE failed to act in the best interests of its customers who
13 historically have been responsible for paying the ESA.

14 **Q. HAS PGE RECEIVED AN INVOICE FOR THE 2018-2019 ESA?**

15 A. Yes. PGE owes \$2,412,208.^{24/}

16 **Q. COULD PGE STILL JOIN A LAWSUIT CHALLENGING THE 2018-2019 ESA?**

17 A. Yes, but PGE has thus far not indicated that it will. Since the ESA is established for a
18 fiscal biennium, the basis for the 2018-2019 ESA is identical to that for the 2017-2018

^{22/} Id. at 2 (PGE Resp. to ICNU DR 013).

^{23/} Oregon’s Administrative Procedure Act imposes a 60-day period for filing challenges to agency decisions other than contested cases. ORS 183.484(2). Oregon courts have held that this statute provides the sole means for challenging such agency actions. Mendieta v. Division of State Lands, 148 Or. App. 586 (1998). Therefore, were PGE to wait to see whether the litigation is successful and then attempt to obtain a refund for itself based on issue preclusion or a similar legal theory, this action likely would fail.

^{24/} Exh. AWEC/307, Hellman/23-25 (PGE Resp. to AWEC DR 137, Attach. 137-A).

1 ESA. If PGE chose not to join the litigation for the 2017-2018 ESA, it would be a
2 change in PGE's behavior were it now to join a lawsuit over the 2018-2019 ESA.

3 **Q. WHAT DO YOU RECOMMEND?**

4 A. I recommend that the Commission disallow the \$2,068,281 PGE has included in its rate
5 case for the ESA. I make this recommendation on two grounds.

6 First, and primarily, PGE acted imprudently and against its customers' interests in
7 not joining the 2017-2018 ESA litigation. This litigation represented the only path for
8 PGE to obtain a refund of its ESA for this fiscal year and was highly likely to succeed
9 based on the Court's ruling on the 2016-2017 ESA. Moreover, because the litigation is
10 being funded by a large group of energy suppliers, this was a low-cost, low-risk
11 opportunity for the Company. PGE will again lose out on the opportunity to obtain a
12 refund of its ESA if, as expected, it fails to join the lawsuit over the 2018-2019 ESA.

13 Second, there is no evidence in the record to show PGE challenged or sought
14 greater detail in the ESA activities and, therefore, PGE has not demonstrated how
15 customers benefit in any way from the ESA. As noted above, ODOE's "full accounting"
16 of the ESA for the 2017-2019 biennium consisted of a single page in a presentation that
17 merely assigns dollars to various departments within the agency without even a cursory
18 explanation of how those dollars are being used and why they are necessary. PGE's ESA
19 is funding ODOE programs that are described simply as "Public Schools,"
20 "Transportation," "Planning, Economics, and Other," and "Director's Office." As the
21 lawsuits demonstrate, companies funding the ESA, such as PGE, do not know the

1 specifics as to how this money is being used (hence the reason for the lawsuits against the
2 ESA), so PGE cannot show that this money is being used to benefit customers.

3 **VII. NON-REVENUE REQUIREMENT ISSUE AND RECOMMENDATION**

4 **Q. DO YOU HAVE ANY NON-REVENUE REQUIREMENT ISSUE TO DISCUSS?**

5 A. Yes. In Exhibit PGE/400, Mersereau-Nietzke/17-18, they highlight that PGE is
6 considering changing the way PGE budgets for its labor-related activities. The testimony
7 on PGE/400, Mersereau-Nietzke/18, lines 1 and 2 state that PGE should “focus on labor
8 costs rather than FTEs.” I think there is merit to this concept not only for PGE’s internal
9 purposes but also for a rate case setting. Focusing on budgets instead of FTEs in a rate
10 case essentially captures in my view what a rate case is.

11 **Q. HOW IS THAT?**

12 A. While I recommend PGE revenue requirements be established using a 2700 FTE level,
13 this is to identify an adjustment that is consistent with how PGE has presented its case.
14 However, PGE is free to choose whatever level of FTEs it thinks best. The Commission
15 sets rates, not the actual number of FTE the Company should have, and PGE is
16 responsible for managing the Company.

17 Focusing on budgets would allow for a more holistic, higher-level view of labor
18 cost where we look at trends in costs in relation to overall workload and fundamental
19 factors. As I noted in my testimony, it is not possible to review every single Company
20 position and decide whether it is warranted or not.

21 I also agree with the sentiment expressed in its testimony that PGE should focus
22 on hiring the right mix of employees and not be as concerned on FTE count.

1 **Q. WHAT DO YOU RECOMMEND?**

2 A. I recommend the Commission direct PGE to file a report with the Commission no later
3 than six months following the Commission's final order in this docket. The report would
4 investigate changing PGE's budgeting approach to dollars instead of FTEs as suggested
5 in Exhibit PGE/400, Mersereau-Neitzke/17-18, along with providing historical data for
6 all labor-related services inclusive of contracted-for and PGE labor resources.

7 **Q. DOES THAT CONCLUDE YOUR TESTIMONY?**

8 A. Yes.

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
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EXHIBIT NO. AWEC/301

QUALIFICATION STATEMENT OF DR. MARC M. HELLMAN

Marc Hellman, PhD.

Witness on Behalf of Alliance of Western Energy Consumers

2760 Eagle Eye Ave NW

Salem, Oregon 97304

WORK EXPERIENCE

Dr. Hellman, of MH Energy Economics LLC, has nearly 40 years' experience in the field of regulatory economics and has consulted for telecommunications and electric industries as well as Boeing Computer Services. Beginning in 1979, Dr. Hellman was employed by the Public Utility Commission of Oregon (OPUC) in various capacities and has specialized in cost-based pricing and revenue requirements analysis for electric, natural gas, telecommunications and water industries. Up to September 2017, Dr. Hellman was Administrator of the Energy Rates, Finance and Audit Division and managed over a dozen expert staff of economists, accountants, and financial analysts dedicated to conducting a wide range of research on such matters including: utility cost of capital, utility financing applications, rate spread and rate design, utility merger and acquisitions, as well as conducting utility audits and benchmarking studies. Most recently in 2013, Dr. Hellman was appointed to advise the Oregon Governor's Office on the Columbia River Treaty review. Dr. Hellman received his PhD in Economics from Claremont Graduate School in 1983, and for several years beginning in 2008, was an instructor at Oregon State University teaching micro and macroeconomics as well as energy economics. Dr. Hellman has also recently provided consulting services for the Commonwealth Utilities Corporation with headquarters in Saipan, the Smart Energy Alliance in a Nevada Power general rate filing before the Nevada Commission, and the South Dakota Intrastate Pipeline Company.

Major Regulatory Studies and Reports

Public Utility Commission of Oregon, – chaired the water industry stakeholder workgroup and led discussions reviewing in total, both in scope of regulation and funding, the Commission Water Regulation Program, with the production of the report titled, "Review of the Oregon Public Utility Commission's Water Program," August 2002.

Public Utility Commission of Oregon, – authored major electric industry restructuring testimony presented before the Oregon Legislature, July 1997.

Public Utility Commission of Oregon, – led and directed Commission staff in reviews of several utility mergers and acquisitions including ScottishPower acquisition of PacifiCorp and Mid American holdings acquisition of PacifiCorp.

Public Utility Commission of Oregon, – led the first known study establishing estimates of unbundled network elements, memorialized in the report titled, "Telecommunications Building Blocks, Cost Report," July 1993.

Public Utility Commission of Oregon, – designed policies to address ratemaking treatment for research and development activities by Advanced Technologies, a fully owned subsidiary of US West, "Alternative Regulatory Policies for Telecommunications Utilities' Research and Development Costs," May 1992.

Public Utility Commission of Oregon, – analyzed and scored many alternative ratemaking mechanisms geared to incent electric utilities to acquire cost-effective conservation, "Investigation into Electric Utility Incentives for Acquisition of Conservation Resources," August 1991.

Public Utility Commission of Oregon, – as a precursor to integrated least cost planning, authored the report titled, "The 1989 Update to a Report on the PGE and PP&L Energy Surplus: Its Size, Duration, and Management," September 1988, as well as, "A Report on the PGE and PP&L Energy Surplus: Its Size, Duration, and Management," September 1989.

Expert Witness Testimony

Alliance of Western Energy Consumers (Washington Utilities and Transportation Commission Docket UE 170970), – testimony in support of Hydro One acquisition of Avista with a focus on commitments relating to large electric energy users. 2018

Smart Energy Alliance (Nevada PUC Docket 17-06003 and 17-06004), residential net metering rates and rate spread for direct access customers. 2017

South Dakota Intrastate Pipeline Company (South Dakota Public Utilities Commission), – management fee, rate proposal for pipeline decommissioning, rate of return. 2017

Public Utility Commission of Oregon (Bonneville Power Administration Docket REP-12), – select panel testimony in support of a \$2 billion settlement of statutory rights to low-cost federal power. 2011

Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-10), – analysis of statutory test that limits access to low-cost federal power by residential and small-farm customers of investor-owned utilities. 2009

Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-07S), – analysis of rights to low-cost federal power by residential and small-farm customers of investor-owned utilities. 2008

Public Utility Commission of Oregon (Docket UM 1050), – analysis of interjurisdictional cost allocation methods applicable to PacifiCorp. Docket was culmination of multi-year collaborative effort among the states of Washington, Idaho, Wyoming, Utah and Oregon to reach an agreed to allocations method. 2004

Public Utility Commission of Oregon (Docket UE 88), – analysis of alternative decoupling mechanisms designed to break the link between utility kWh sales and utility profits applicable to PacifiCorp. 1994

Public Utility Commission of Oregon (Docket UE 79), – ratemaking analysis of Portland General Electric wholesale power sales relating to the WNP #3 Settlement. 1990

Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-87), – analysis of rights to low-cost federal power by residential and small-farm customers of investor-owned utilities. 1987

Public Utility Commission of Oregon (Federal Energy Regulatory Commission Docket ER 82-2011-003), – economics of nonfirm energy production in the Pacific Northwest and pricing of such power. 1984

Public Utility Commission of Oregon (Bonneville Power Administration Docket WP-83), – analysis of rights to low-cost federal power by residential and small-farm customers of investor-owned utilities, value of Direct Service Industry reserves, estimates of the Pacific Northwest Region long run incremental cost of wholesale power.

Telecommunications

- *Public Utility Commission of Oregon* – “The Status of Competition and Regulation in the Telecommunications Industry,” – separate studies published roughly each year beginning in 2001.
- *Public Utility Commission of Oregon (Docket UM 351, Phase II)*, – general pricing and unbundling policies for telecommunications retail services and unbundled network elements – 1995.
- *Public Utility Commission of Oregon (Docket UM 351)*, – generic investigation to develop long run incremental cost of unbundled network elements – 1993.
- *Public Utility Commission of Oregon (UM 295)*, – ratemaking policies for telecommunications research and development activities – 1992.
- *Public Utility Commission of Oregon (UT 80)*, – alternative form of regulation review and proposal for US West – 1991.
- *Public Utility Commission of Oregon (US WEST Docket UT 85)*, – broad pricing policy – 1989.
- *Public Utility Commission of Oregon (PNB Docket UF 3565)*, – telecommunications pricing issues, review of price elasticity studies, Western Electric Adjustment – 1980.

EDUCATION

CLAREMONT GRADUATE SCHOOL, CLAREMONT, CALIFORNIA – MA, 1980, PhD, 1983

- Specialization in Optimization Theory/Microeconomic Theory/Monetary Economics.

CALIFORNIA STATE POLYTECHNIC UNIVERSITY OF POMONA -- BS, 1977

- Major in Mathematics and Economics.

OTHER

- Graduate of 1997 Leadership Oregon Program. Each year, from all state employees, 20 to 30 future government leaders are selected to participate in LOP to learn about other state agencies and benefit from executive training.
- Member, American Economic Association
- Economics at Oregon State University

PUBLICATIONS

The Economics of a Surplus in Electrical Generating Capability: The Pacific Northwest," - Public Utilities Fortnightly, January 5, 1984, pages 45-47.

Load Curve Responsiveness to Weather and the Cost Effectiveness of Conservation," - Public Utilities Fortnightly, September 30, 1982, page 51.

FORMAL TESTIMONY OFFERED IN THE FOLLOWING PROCEEDINGS:

<u>Cause</u>	<u>Agency</u>	<u>Year</u>	<u>Company</u>	<u>Topics</u>
R-48	OPUC	1980	Generic-Electric	Conservation potential from electric rate design
UF 3565	OPUC	1980	PNB	Telecommunication pricing issues, review of elasticity studies, Western Electric Adjustment
UF 3753	OPUC	1982	CPN	LRIC methodology, electric rate spread and rate design
UF 3779	OPUC	1982	PP&L	LRIC and electric rate spread, and rate design
UF 3900	OPUC	1983	PP&L	LRIC and electric rate spread, and rate design
WP 83	BPA	1983	BPA	LRIC methodology and value of DSI energy and capacity reserves
AR 112	OPUC	1984	Generic-Electric	Electric LRIC methodology and rate spread and rate design policy
ER 82-2011-003	FERC	1984	BPA	Economics of nonfirm electric energy sales to the Pacific Southwest
UE 44	OPUC	1985	Generic-Electric	Electric rate spread and rate design, LRIC methodology
UE 47/48	OPUC	1986	PGE	Electric rate spread and rate design, valuation of WNP #3 settlement agreement
VI-86-OP-01	BPA	1986	BPA	Review of BPA proposed Variable Industrial Power Rate
UE 58	OPUC	1987	PP&L	Electric rate spread and rate design
UE 70	OPUC	1987	PP&L	LRIC methodology and electric rate spread and rate design
WP 87	BPA	1987	BPA	7(b)(2) rate test
UT 85	OPUC	1989	USWC	Telecommunications rate design policies

<u>Cause</u>	<u>Agency</u>	<u>Year</u>	<u>Company</u>	<u>Topics</u>
UT 80	OPUC	1991	USWC	Telecommunications alternative form of regulation summary witness and productivity estimation
UM 295	OPUC	1992	Generic-Telecommunications	Ratemaking policy for telecommunications research and development activities
UE 88	OPUC	1994	PGE	Decoupling mechanism design to break link between kWh sales and utility profits
UM 351, Phase II	OPUC	1995	Generic-Telecommunications	General pricing and unbundling policies of telecommunications functionalities
UM 1050	OPUC	2004	PacifiCorp	Interjurisdictional cost allocation methods
WP-07S	OPUC	2008	BPA	7(b)(2) rate test, retroactive ratemaking
WP-10	OPUC	2009	BPA	7(b)(2) rate test
REP-12	OPUC	2011	BPA	Long-term residential exchange settlement
Docket No. 17-06003 and 17-06004	Nevada PUC	2017	Smart Energy Alliance	Residential net metering rates and rate design for direct access customers
Docket No. NG17-009	South Dakota PUC	2017	South Dakota Intrastate Pipeline Company	Rate of Return, Decommissioning policy, and management fee
Docket No. U-170970	Washington UTC	2018	Alliance of Western Energy Consumers	Merger rate credit design, merger benefits, larger industrial conservation option

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
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CONFIDENTIAL EXHIBIT NO. AWEC/302
BUDGET MANUAL INSTRUCTIONS FOR 2016 AND 2017
(REDACTED VERSION)

Exhibit AWEC/302 contains Protected Information and has been redacted in its entirety in accordance with Order No 18-047.

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
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EXHIBIT NO. AWEC/303

OLS OUTPUT RESULTS FOR COMPARABLE COMPANY ANALYSIS

[illegible]

[illegible]

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
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CONFIDENTIAL EXHIBIT NO. AWEC/304

PGE BENEFITS RANKING

(REDACTED VERSION)

Exhibit AWEC/304 contains Protected Information and has been redacted in its entirety in accordance with Order No. 18-047.

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
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Request for a General Rate Revision.)
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**CONFIDENTIAL EXHIBIT NO. AWEC/305
PGE INCENTIVE PROGRAM EXAMPLES
(REDACTED VERSION)**

Exhibit AWEC/305 contains Protected Information and has been redacted in its entirety in accordance with Order No. 18-047.

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
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EXHIBIT NO. AWEC/306

AVERAGE TO BUDGET INCENTIVES PERCENTAGES PAYOUT

[illegible]

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
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EXHIBIT NO. AWEC/307
PGE RESPONSES TO DATA REQUESTS

March 13, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to ICNU Data Request No. 012
March 2, 2018**

Request:

Please identify the amount included in the test year for PGE's energy supplier assessment. Please also explain whether this amount applies to PGE's 2018 ESA, its 2019 ESA, an average of the two, or something else.

Response:

PGE included \$2,068,281 in its 2019 test year forecast for the energy supplier assessment (ESA). This amount is the same as the 2016-2017 Oregon State Fiscal Year invoice. PGE's actual ESA cost for the 2017-2018 Oregon State Fiscal Year is \$2,407,834.

Based on the recent years' increases in the ESA fees, PGE is currently forecasting to pay higher fees than the amount included in the test year revenue requirement.

March 13, 2018

TO: Mark Brown
Public Utility Commission of Oregon

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to ICNU Data Request No. 013
March 2, 2018**

Request:

Please explain why PGE chose not to join in the currently pending litigation over the energy supplier assessment.

Response:

PGE objects to this request on the basis that the information it seeks is not relevant or reasonably calculated to lead to the discovery of admissible evidence in the current proceeding. Without waiving this objection, PGE responds as follows:

The current litigation involves the 2017 energy supplier assessment (ESA) made by the Oregon Department of Energy (ODOE) pursuant to ORS 469.421, and pursuant to a legislatively adopted expenditure limit. Initially, a small group of public utilities challenged the 2016 ESA, and the Marion County Circuit Court determined that the process followed by ODOE in making that assessment was not sufficient to meet the requirements of the statute. Subsequently, a larger group of public utilities challenged the 2017 ESA. Other than Cascade Natural Gas, no investor owned utility joined in either suit.

Ultimately, PGE decided to: 1) not join the suit over the 2017 ESA; but to 2) support the public utility petitioners in their appeal of the 2016 ESA, potentially by filing an Amicus brief. This decision was based on a number of factors including:

- The broader issues raised in the 2016 ESA case, including the question of whether the ESA is a tax or a fee, deserve additional judicial review.
- The raising of similar issues in the 2017 case, and the potential determination of those issues by a lower court, will have no additional effect on the legitimacy or legality of the ESA that is not already served by monitoring and participating in the appeal of the 2016 case.

- Any outcome in the 2016 ESA appeal will have no effect on the current funding cycle and, should the determination be negative for ODOE, will not affect expenditures in the current biennium.

April 26, 2018

TO: Tyler Pepple
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 038
April 12, 2018**

Request:

Please provide the amount of PGE's energy supplier assessment for each year since 2013 (inclusive).

Response:

Attachment 038-A provides PGE's energy supplier assessment payments from 2013 through 2017.

UE 335 PGE Response to AWEC DR No. 038
Attachment 038-A
Page 1

PGE Energy Resource Supplier Assessment Payments to ODOE

Year	Amount Paid	
2013	\$	1,373,770
2014	\$	1,362,501
2015	\$	1,971,706
2016	\$	2,068,281
2017	\$	2,407,834

May 9, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 049
Dated April 25, 2018**

Request:

Please refer to PGE/400, Mersereau – Neitzke/2, Table 1. For the three components listed, Wages and Salaries, Incentives and Benefits, provide:

- a. both the Actuals and Budget for each year beginning 2012 through 2017, identifying dollar values separately for expensed and capitalized;**
- b. do Wages and Salaries reflect both union and non-union workers?**
- c. please list the incentives and the respective dollar amounts included. For example, do the values included in the table include officer incentives?**
- d. does the actual category and budget category encompass the same types of costs such that they are a direct match? If not, please explain.**

Response:

- a. PGE's Attachment 049-A provides the requested information. PGE is unable to provide budgeted health and dental plan information for 2012 at a greater level of detail because the accounts are not comparable to those from 2013-2017 due to the conversion of PGE's accounting system.
- b. Yes, wages and salaries represent both union and non-union employees.
- c. PGE's Attachment 049-A provides the requested information.
- d. Yes, the budget and actual amounts represent the same type of costs. 2012 budget data are based on conversion data from PGE's prior accounting system and may not be fully comparable.

Total Compensation Summary (\$000)													
		2012 Budget ^{d,f}	2012 Actual	2013 Budget	2013 Actual	2014 Budget	2014 Actual	2015 Budget	2015 Actual	2016 Budget	2016 Actual	2017 Budget	2017 Actuals
Incentive Compensation													
	Total ACI	5,071	5,200	5,855	5,181	6,361	6,620	6,542	6,404	6,659	5,448	6,548	7,379
	Total Stock Incentive Plan	3,550	4,269	4,632	4,323	5,476	5,918	6,352	6,023	6,957	6,427	7,335	6,668
	Total Notables & Misc.	267	448	257	666	257	807	257	1,036	307	1,502	662	1,215
	Total Gross Incentives	17,744	17,816	21,176	18,138	24,745	25,255	26,318	23,510	27,957	24,526	32,498	32,064
	Incentive Loadings to Capital	(2,730)	(2,390)	(2,950)	(2,510)	(3,700)	(4,020)	(2,560)	(2,650)	(2,910)	(2,960)	(4,280)	(3,840)
	Incentives Net of Capital	15,014	15,426	18,226	15,628	21,045	21,235	23,758	20,860	25,047	21,566	28,218	28,224
	ACI = Annual Cash Incentive												
Wages & Salaries													
	Capital	68,614	67,539	65,889	64,935	70,972	67,627	73,893	71,224	79,152	78,708	92,693	93,343
	O&M	143,636	141,385	145,185	143,085	150,914	143,802	154,453	148,875	154,749	153,880	166,180	167,345
	Gross Wages and Salaries	212,249	208,924	211,074	208,020	221,886	211,429	228,345	220,099	233,901	232,588	258,873	260,689
Benefit Compensation													
		2012 Budget	2012 Actual	2013 Budget	2013 Actual	2014 Budget	2014 Actual	2015 Budget	2015 Actual	2016 Budget	2016 Actual	2017 Budget	2017 Actuals
	Total Health & Dental Plan	37,016	37,098	39,425	37,269	39,298	38,843	41,160	40,797	41,759	40,548	45,472	40,759
	Total Gross Benefits	81,934	82,452	94,505	90,869	92,308	89,555	90,704	92,398	91,000	90,919	96,751	90,218
	Benefits Loadings to Capital	(22,420)	(22,770)	(24,690)	(25,320)	(24,270)	(25,110)	(24,750)	(26,540)	(26,030)	(27,450)	(31,420)	(29,570)
	Benefits Net of Capital	59,514	59,682	69,815	65,549	68,038	64,445	65,954	65,858	64,970	63,469	65,331	60,648
	Total Gross Compensation	311,927	309,192	326,755	317,026	338,939	326,239	345,367	336,006	352,858	348,033	388,122	382,971
	Total Compensation Net of Capital	218,164	216,493	233,227	224,261	239,997	229,482	244,164	235,592	244,766	238,915	259,729	256,218
	Total Compensation (as presented in Exhibit 400)	299,611	298,629	312,109	302,054	324,896	313,727	332,126	323,748	340,876	337,254	376,797	371,231

- a Actual incentives reflect PGE's 100% of the Officer Long-term Incentive Program costs and of all other incentives plans.
b Split for capital and O&M actuals applied to capital and O&M budget split
c Pension cost forecast (before capitalization)
d 2012 Wages & Salaries do not include an unfilled position adjustment
e Accounts are not comparable to 2013-2017 at this level of detail
f 2012 Budget data is based on conversion data from PGE's prior accounting system and may not be fully comparable
g Only PIC and Notable Achievement Awards have capital loadings. ACI, Stock Incentives, Notable, and Miscellaneous Awards don't have capital loadings.

		2012 Budget ^{d,f}	2012 Actual	2013 Budget	2013 Actual	2014 Budget	2014 Actual	2015 Budget	2015 Actual	2016 Budget	2016 Actual	2017 Budget	2017 Actuals
Incentive Compensation													
	Capital	15%	13%	14%	14%	15%	16%	10%	11%	10%	12%	13%	12%
	Operating	85%	87%	86%	86%	85%	84%	90%	89%	90%	88%	87%	88%
Wages & Salaries													
	Capital	32%	32%	31%	31%	32%	32%	32%	32%	34%	34%	36%	36%
	Operating	68%	68%	69%	69%	68%	68%	68%	68%	66%	66%	64%	64%
Benefit Compensation													
	Capital	27%	28%	26%	28%	26%	28%	27%	29%	29%	30%	32%	33%
	Operating	73%	72%	74%	72%	74%	72%	73%	71%	71%	70%	68%	67%

May 9, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 066
Dated April 25, 2018**

Request:

Please refer to PGE/400, Mersereau - Neitzke/17, lines 11-14.

- a. Did PGE exclude all other components of compensation relating to the 99.9 FTE adjustment inclusive of wages and which is captured in the \$10 million adjustment?**
- b. Please provide a breakdown of an adjustment of 99 .9 FTE for the components of total compensation such as wages and benefits.**
- c. Do the forecasted FTEs included in prior Tables include total FTE required, including vacancies, or are the totals net of vacancies and hence the number of FTEs listed are actually 99.9 FTE less than total PGE positions?**

Response:

- a. PGE's \$10 million wage and salary adjustment to expense costs represents vacancies and/or unfilled positions that occur during a calendar year. Except for vacation, the cost of the other components of total compensation such as benefits and incentives are not included in the \$10 million. However, PGE budgets its benefits and incentives based on the most current information available and considering vacancies, as well as employee participation and qualification levels (e.g., PGE assumed 2,852 FTEs for medical benefits in 2019, which is approximately 15 FTE less than PGE's 2019 forecasted FTE, net of adjustments). At the same time, the calculations/estimates for some benefits are not based on FTEs, but on other factors, such as headcount. This is due to different timing, assumptions about their start and end dates, different offering, options, as well as rules and regulations.

PGE's 2019 401(k) plan assumes 3,037 participants (headcount, not FTE). PGE's response to OPUC Data Request No. 223 provides the 401(k) participants from 2014-2019.

For the 2019 incentives budget detail, please see PGE's response to OPUC Data Request No. 191, Confidential Attachment B.

- b. Please see response to item (a) above for explanation on how benefits and incentives are budgeted. PGE Exhibit 400 non-confidential workbook "2015 - 2019_FTE_W&S" provides wage and salary detail with the \$10 million adjustment in 2019.
- c. The FTE tables provided in PGE Exhibit 400 represent the total FTEs PGE requires to run its operations less the estimated 99.9 FTEs representing the \$10 million adjustment for vacancies and/or unfilled positions.

May 9, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 067
Dated April 25, 2018**

Request:

Please refer to PGE/400, Mersereau- Neitzke/21, Table 7. Please:

- a. provide values for Table 7 for total incentives PGE has budgeted for 2019 excluding any adjustment;**
- b. provide a breakdown of these values by the categories of officer, performance and merit based;**
- c. demonstrate that based on these values and the values provided in testimony that 100% of officer incentives have been excluded;**
- d. provide the value of total incentives paid by PGE, broken down by officer, performance and merit, for the years 2012 through 2017 inclusive.**

Response:

- a. Attachment 067-A, column "J", provides the 2019 forecast without PGE's filing adjustments.
- b. PGE's response to OPUC Data Request No. 191, Attach B_CONF provides the merit and financial breakdown requested.
- c. Attachment 067 A, column "L", provides the total incentive adjustment, which matches the adjustment to PGE's revenue requirement as found in "Exhibit Support 2019_Tax Plan" file and "A&G" tab.
- d. Attachment 067-A provides the 2012 to 2017 incentives paid by PGE broken down by incentive type. Incentives are paid based on PGE's financial performance and individual employee scorecard achievement. Please refer to the documentation provided as confidential work papers in PGE's Exhibit 400, for the financial and merit ratios applicable to each incentive plan.

Total Incentives (\$000)											
Incentive Compensation	2012	2013	2014	2015	2016	2017	2018 Budget	2019 Forecast (Unadjusted)	2019 Adjustment %	2019 Adjustment Amount	2019 Forecast (w/adjustments)
Boardman PIC	120	153	230	191	2	-	-	-			-
Coyote Springs PIC	408	191	251	466	438	39	370	384	50%	(192)	192
Port Westward PIC	443	510	635	678	601	675	607	699	50%	(350)	350
Carty PIC				-	514	648	528	590	50%	(295)	295
Pelton PIC	10	13	18	17	18	29	9	35	50%	(18)	18
Biglow Canyon PIC	29	34	54	21	65	52	37	71	50%	(35)	35
Tucannon River PIC				24	12	22	32	42	50%	(21)	21
PGE General Operations PIC	4,498	4,558	6,695	6,001	6,539	11,497	13,059	13,537	50%	(6,769)	6,769
Total PIC	5,509	5,458	7,883	7,397	8,189	12,962	14,642	15,360		(7,680)	7,680
Boardman ACI	45	22	15	35	14	3	-	-	50%	0	-
Pelton ACI	14	18	18	17	15	20	21	22	50%	(11)	11
Wholesale Marketing ACI	1,200	1,275	1,285	1,388	1,122	1,420	1,470	1,421	50%	(711)	711
PGE General Operations ACI	2,304	2,540	3,052	2,616	2,321	3,137	2,974	3,348	50%	(1,674)	1,674
Officer ACI	1,637	1,326	2,250	2,348	1,976	2,799	2,475	2,089	50%	(1,045)	1,045
Total ACI	5,200	5,181	6,620	6,404	5,449	7,379	6,940	6,881		(3,440)	3,440
PGE Stock Incentives	1,796	1,877	2,196	1,224	1,376	1,657	2,141	2,209	50%	(1,104)	1,104
Officer Stock Incentives	2,473	2,446	3,721	4,049	4,228	4,157	5,281	4,945	100%	(4,945)	-
Board of DirectorS Stock Incentives				750	823	854	900	936	50%	(468)	468
Total Stock Incentive Plan	4,269	4,323	5,917	6,023	6,427	6,668	8,322	8,090		(6,518)	1,572
Notable Achievement Awards	409	638	567	770	1,427	933	667	667	50%	(333)	333
Miscellaneous Awards	39	28	240	266	75	282	-	-	0%	0	-
Total Notables & Misc.	448	666	807	1,036	1,502	1,215	667	667		(333)	333
Total Incentives	15,426	15,628	21,227	20,860	21,567	28,224	30,570	30,998		(17,971)	13,026

PIC = Performance Incentive Compensation
ACI = Annual Cash Incentive

May 10, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 073
Dated April 25, 2018**

Request:

Please refer to PGE/400, Mersereau - Neitzke/36, lines 1 - 8.

- a. Has PGE's proposal to update the discount rate under similar timelines as proposed in this case been proposed and accepted by other parties in prior PGE general rate cases?**
- b. Please describe the effects on the level of annual FAS 87 pension costs if the discount rate increases by 0.1 percent.**
- c. Is the effect on FAS 87 pension costs linearly related to each percentage point change in discount rate?**

Response:

- a. PGE made a similar request in its 2018 test-year general rate case (Docket No. UE 319). During that proceeding, PGE provided (via PGE's first supplemental response to OPUC Data Request No. 178) updated discount rates for both pension and post-retirement costs. These changes resulted in a net-neutral effect to costs. Ultimately, no change to discount rates for either pension or post-retirement costs were proposed or made during the UE 319 proceeding.
- b. A 10 basis point increase to PGE's discount rate used for FAS 87 pension expense would reduce PGE's gross (i.e., pre-capitalization) pension expense by approximately \$860,000.
- c. No. As discount rates decrease, the sensitivity (on a percentage basis) to changes is more pronounced. Similarly, as discount rates increase, the sensitivity to changes is lower on an overall percent change basis.

May 14, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 093
May 1, 2018**

Request:

Please identify, for each year of the time period 2010 through 2019, inclusive;

- a. PGE gross and net distribution plant;**
- b. By month for the same time period, PGE residential, commercial, industrial and total retail loads, unadjusted;**
- c. PGE residential, commercial, industrial and total retail loads normalized for the weather;**
- d. PGE residential, commercial, industrial and total retail loads normalized for weather;**
- e. The number of each of residential, commercial, industrial and total retail customers year end; and**
- f. Actual and budgeted medical expense separated out by union and non-union**

For the years 2018 and 2019, only projected values, consistent with PGE's general rate filing need be provided, as available.

Response:

- a. Attachment 093-A provides the requested information for 2010 to 2017. PGE's response to OPUC Data Request No. 128, Attachment 128-D, provides the forecasted 2018 year-end balances. PGE is not filing 2019 year-end balances in this rate case.
- b. Attachment 093-B provides the requested information.
- c. Attachment 093-C provides the requested information.
- d. Attachment 093-C provides the requested information.
- e. Attachment 093-D provides the requested information.
- f. Attachment 093-E provides the requested information.

Attachment 093-E is protected information and subject to Protective Order 18-047.

UE 335 PGE Response to AWEC DR No. 093
Attachment 093-A
Page 1

AWEC 93 (a) PGE Gross and Net Plant Balance for Electric Plant in Service Classified as Distribution

Data is from PGE's filed FERC Form 1 for each year from 2010 through 2017.

YEAR	Plant		Reserve		Net Plant	
2010	\$	2,569,836,052	\$	1,380,886,914	\$	1,188,949,138
2011	\$	2,690,710,541	\$	1,479,972,471	\$	1,210,738,070
2012	\$	2,809,739,430	\$	1,585,049,949	\$	1,224,689,481
2013	\$	2,939,069,492	\$	1,686,819,395	\$	1,252,250,097
2014	\$	3,070,652,586	\$	1,792,248,824	\$	1,278,403,762
2015	\$	3,186,283,644	\$	1,849,206,854	\$	1,337,076,790
2016	\$	3,334,113,440	\$	1,939,890,596	\$	1,394,222,844
2017	\$	3,534,104,917	\$	2,028,237,016	\$	1,505,867,901

b. by month for the same time (2010-2019) period, PGE residential commercial industrial and total retail loads, unadjusted

Monthly Energy Deliveries, actual through 2017, in thousands of MWh

Year	Month	Residential	Commercial	Industrial	Total
2010	1	874	642	321	1,836
2010	2	726	619	317	1,661
2010	3	662	599	304	1,565
2010	4	617	572	309	1,498
2010	5	553	562	312	1,427
2010	6	540	582	323	1,444
2010	7	536	612	326	1,475
2010	8	568	677	347	1,592
2010	9	539	647	344	1,529
2010	10	509	599	347	1,455
2010	11	595	600	350	1,546
2010	12	810	626	357	1,792
2011	1	882	654	353	1,889
2011	2	765	616	361	1,742
2011	3	769	637	342	1,747
2011	4	651	583	335	1,569
2011	5	580	564	335	1,479
2011	6	533	582	344	1,458
2011	7	504	608	342	1,454
2011	8	533	659	368	1,559
2011	9	562	674	365	1,601
2011	10	515	602	348	1,466
2011	11	617	591	342	1,550
2011	12	813	638	330	1,781
2012	1	889	668	339	1,897
2012	2	780	646	351	1,777
2012	3	737	621	338	1,695
2012	4	629	576	338	1,543
2012	5	534	572	347	1,453
2012	6	510	586	362	1,457
2012	7	525	622	356	1,503
2012	8	548	649	359	1,556
2012	9	537	658	373	1,568
2012	10	498	603	367	1,468
2012	11	584	584	362	1,530
2012	12	758	621	343	1,722
2013	1	894	649	355	1,898
2013	2	763	608	351	1,723
2013	3	669	585	329	1,584
2013	4	584	576	346	1,506
2013	5	541	597	354	1,493
2013	6	513	597	357	1,467
2013	7	558	641	351	1,550
2013	8	564	671	369	1,604
2013	9	566	673	385	1,624
2013	10	529	583	357	1,469
2013	11	582	576	357	1,515
2013	12	879	667	360	1,906
2014	1	879	656	368	1,902
2014	2	794	617	347	1,758
2014	3	679	599	322	1,599
2014	4	586	577	352	1,515
2014	5	532	586	339	1,457
2014	6	495	613	354	1,462
2014	7	554	650	360	1,564
2014	8	614	692	374	1,680
2014	9	581	698	392	1,672
2014	10	489	601	358	1,447
2014	11	572	588	364	1,525

UE 335 PGE Response to AWEC DR No. 093
Attachment 093-A
Page 2

2014	12	783	653	374	1,809
2015	1	803	640	380	1,822
2015	2	655	592	362	1,609
2015	3	590	579	359	1,528
2015	4	560	577	364	1,501
2015	5	519	590	373	1,482
2015	6	527	631	392	1,550
2015	7	646	705	393	1,743
2015	8	615	696	398	1,708
2015	9	553	671	413	1,638
2015	10	478	594	378	1,450
2015	11	562	597	392	1,551
2015	12	806	643	374	1,824
2016	1	877	666	338	1,881
2016	2	674	598	335	1,608
2016	3	625	582	317	1,525
2016	4	555	575	330	1,460
2016	5	499	569	336	1,404
2016	6	532	628	345	1,505
2016	7	520	623	346	1,488
2016	8	553	643	365	1,561
2016	9	571	661	364	1,596
2016	10	494	585	351	1,429
2016	11	539	578	343	1,460
2016	12	765	628	362	1,755
2017	1	993	678	351	2,022
2017	2	845	651	358	1,855
2017	3	731	631	337	1,699
2017	4	603	581	343	1,527
2017	5	544	569	356	1,469
2017	6	528	610	365	1,503
2017	7	560	641	355	1,556
2017	8	616	677	377	1,670
2017	9	615	688	389	1,692
2017	10	515	605	359	1,478
2017	11	569	578	344	1,491
2017	12	767	644	350	1,760
2018 (f)	1	879	650	343	1,873
2018 (f)	2	756	613	340	1,709
2018 (f)	3	694	606	332	1,632
2018 (f)	4	596	576	338	1,510
2018 (f)	5	529	570	339	1,438
2018 (f)	6	516	607	345	1,468
2018 (f)	7	540	633	353	1,526
2018 (f)	8	577	670	366	1,614
2018 (f)	9	570	676	372	1,618
2018 (f)	10	498	595	355	1,447
2018 (f)	11	567	576	346	1,488
2018 (f)	12	789	618	352	1,759
2019 (f)	1	881	642	349	1,871
2019 (f)	2	756	605	345	1,706
2019 (f)	3	693	598	338	1,628
2019 (f)	4	594	567	343	1,505
2019 (f)	5	527	562	344	1,433
2019 (f)	6	514	599	351	1,463
2019 (f)	7	540	625	359	1,523
2019 (f)	8	578	662	372	1,612
2019 (f)	9	571	668	377	1,616
2019 (f)	10	497	586	361	1,443
2019 (f)	11	566	566	351	1,484
2019 (f)	12	790	609	358	1,757

c. and d. PGE residential commercial industrial and total retail loads normalized for weather

Monthly Energy Deliveries, actual through 2017, weather adjusted, in thousands of MWh

Year	Month	Residential	Commercial	Industrial	Total
2010	1	848	638	320	1,806
2010	2	793	630	319	1,742
2010	3	703	604	305	1,612
2010	4	603	571	309	1,482
2010	5	541	563	312	1,416
2010	6	514	587	324	1,424
2010	7	530	619	328	1,477
2010	8	579	686	349	1,614
2010	9	541	654	345	1,540
2010	10	521	600	347	1,467
2010	11	608	602	350	1,560
2010	12	774	621	356	1,751
2011	1	867	651	353	1,871
2011	2	792	619	361	1,773
2011	3	704	627	341	1,672
2011	4	609	577	334	1,520
2011	5	548	564	335	1,447
2011	6	510	585	345	1,440
2011	7	519	620	344	1,483
2011	8	554	674	370	1,598
2011	9	554	664	364	1,582
2011	10	519	599	347	1,465
2011	11	611	588	341	1,541
2011	12	786	631	329	1,746
2012	1	902	664	339	1,905
2012	2	782	646	351	1,779
2012	3	704	615	337	1,656
2012	4	615	574	338	1,527
2012	5	547	571	347	1,465
2012	6	508	589	363	1,459
2012	7	528	626	357	1,511
2012	8	552	649	359	1,560
2012	9	537	656	372	1,565
2012	10	506	602	366	1,475
2012	11	615	591	362	1,569
2012	12	804	629	344	1,777
2013	1	870	642	354	1,866
2013	2	758	608	351	1,718
2013	3	690	588	330	1,608
2013	4	621	580	346	1,547
2013	5	566	597	354	1,516
2013	6	523	599	358	1,480
2013	7	555	633	350	1,537
2013	8	565	671	369	1,605
2013	9	555	662	384	1,600
2013	10	503	584	357	1,444
2013	11	590	576	357	1,523
2013	12	813	651	358	1,822
2014	1	880	651	367	1,898
2014	2	733	614	346	1,692

PGE Response to AWEC DR No. 093
Attachment 093-C
Page 2

2014	3	684	602	322	1,608
2014	4	619	582	353	1,554
2014	5	554	584	339	1,477
2014	6	522	616	355	1,492
2014	7	551	644	359	1,554
2014	8	597	678	372	1,646
2014	9	571	686	390	1,648
2014	10	515	596	357	1,468
2014	11	597	595	365	1,557
2014	12	795	656	374	1,825
2015	1	862	651	381	1,895
2015	2	766	615	365	1,746
2015	3	690	600	362	1,652
2015	4	616	588	366	1,569
2015	5	550	594	373	1,516
2015	6	523	614	390	1,527
2015	7	551	661	386	1,598
2015	8	569	679	395	1,643
2015	9	537	667	413	1,617
2015	10	502	594	377	1,473
2015	11	601	603	392	1,595
2015	12	800	645	375	1,819
2016	1	866	666	338	1,870
2016	2	786	624	338	1,748
2016	3	710	602	319	1,632
2016	4	616	584	331	1,530
2016	5	538	566	335	1,439
2016	6	522	617	343	1,482
2016	7	531	626	347	1,503
2016	8	556	644	365	1,565
2016	9	549	654	363	1,566
2016	10	506	589	351	1,446
2016	11	610	595	345	1,549
2016	12	814	639	364	1,817
2017	1	852	643	347	1,843
2017	2	742	630	355	1,728
2017	3	691	623	336	1,650
2017	4	600	582	343	1,525
2017	5	524	565	356	1,445
2017	6	520	603	364	1,487
2017	7	549	634	354	1,537
2017	8	589	668	376	1,634
2017	9	553	663	385	1,601
2017	10	493	600	358	1,451
2017	11	581	582	345	1,508
2017	12	803	653	351	1,807
2018 (f)	1	879	650	343	1,873
2018 (f)	2	756	613	340	1,709
2018 (f)	3	694	606	332	1,632
2018 (f)	4	596	576	338	1,510
2018 (f)	5	529	570	339	1,438
2018 (f)	6	516	607	345	1,468
2018 (f)	7	540	633	353	1,526
2018 (f)	8	577	670	366	1,614
2018 (f)	9	570	676	372	1,618

PGE Response to AWEC DR No. 093
Attachment 093-C
Page 3

2018 (f)	10	498	595	355	1,447
2018 (f)	11	567	576	346	1,488
2018 (f)	12	789	618	352	1,759
2019 (f)	1	881	642	349	1,871
2019 (f)	2	756	605	345	1,706
2019 (f)	3	693	598	338	1,628
2019 (f)	4	594	567	343	1,505
2019 (f)	5	527	562	344	1,433
2019 (f)	6	514	599	351	1,463
2019 (f)	7	540	625	359	1,523
2019 (f)	8	578	662	372	1,612
2019 (f)	9	571	668	377	1,616
2019 (f)	10	497	586	361	1,443
2019 (f)	11	566	566	351	1,484
2019 (f)	12	790	609	358	1,757

PGE Response to AWEC DR No. 093
Attachment 093-D
Page 1

e. the number for each of residential, commercial, industrial, and total retail customers year end

End of Period Customer Count, actual through 2017

Year	Residential	Commercial	Industrial	Total
2010	719,031	101,385	260	820,676
2011	721,216	101,942	255	823,413
2012	725,502	102,594	258	828,354
2013	732,341	103,541	260	836,142
2014	738,008	104,010	255	842,273
2015	746,969	104,940	255	852,164
2016	756,675	105,826	263	862,764
2017	767,012	107,289	267	874,568
2018(f)	776,233	108,274	269	884,776
2019(f)	785,781	109,381	271	895,433

(f) refers to forecasted loads.

Benefit Compensation (\$000)	2012 Budget ^{a,b}	2012 Actual	2013 Budget	2013 Actual	2014 Budget	2014 Actual
Active Union Health & Dental	c	11,003	12,007	12,226	12,713	13,485
Retiree Union Health & Dental	c	1,797	2,026	1,859	1,750	1,852
Active Non-Union Health & Dental	c	23,175	23,704	21,804	23,225	22,035
Retiree Non-Union Health & Dental	c	967	1,487	1,179	1,209	1,265
Health & Dental Administration	c	156	201	201	401	205
Total Health & Dental Plan	37,016	37,098	39,425	37,269	39,298	38,843

a 2012 Budget data is based on conversion data from PGE's prior accounting system and may not be fully comparable

b Accounts are not comparable to 2013-2017 at this level of detail

2015 Budget	2015 Actual	2016 Budget	2016 Actual	2017 Budget	2017 Actuals	2018 Budget	2019 Forecast
12,817	13,612	12,001	11,650	13,068	12,087	14,412	15,088
1,609	1,510	1,394	263	304	19	375	375
25,026	24,047	26,734	26,547	30,193	27,743	34,654	36,721
1,344	1,234	1,307	1,570	1,542	731	660	792
364	394	323	518	365	179	402	407
41,160	40,797	41,759	40,548	45,472	40,759	50,503	53,383

May 29, 2018

TO: Hayley Thomas
Davison Van Cleve, P.C.

FROM: Stefan Brown
Manager, Regulatory Affairs

**PORTLAND GENERAL ELECTRIC
UE 335
PGE Response to AWEC Data Request No. 137
Dated May 15, 2018**

Request:

Please provide PGE's energy supplier assessment for the fiscal year beginning July 1, 2018 when it is available.

Response:

Attachment 137-A provides the invoice for PGE's energy supplier assessment for the fiscal year beginning July 1, 2018. PGE will provide a supplemental response with a signed copy of the assessment on the payment due date by June 30, 2018.

625 MARION STREET NE
SALEM, OR 97301-3737
PHONE: (503) 378-3268
OREGON TOLL FREE 1-800-221-8035 x368
FEDERAL ID NO: 93-0643773

AR190463

05/22/18

06/30/18

PORTLAND GENERAL ELECTRIC
ATTN: NATALIA PAVLOVA/JEFF STEVENS
121 SW SALMON ST
ONE WORLD TRADE CTR 5TH FLR (1WTC0501)
PORTLAND, OR. 97204

DESCRIPTION	CHARGES
Energy Resource Supplier Assessment - State Fiscal Year 2018-2019 Calendar year 2017	2,412,208.00
	Amount Due
	\$ 2,412,208.00

For questions concerning this invoice, call (503) 378-3268.
Please return the remittance copy or include the invoice number on your check stub.

ORS469.421 (11) (B), REQUIRES A PENALTY FEE OF 2% PER MONTH TO BE ASSESSED ON ALL PAST DUE BALANCES

CUSTOMER COPY

OREGON DEPARTMENT OF ENERGY
625 MARION STREET NE
SALEM, OR 97301-3737
PHONE: (503) 378-3268
OREGON TOLL FREE 1-800-221-8035 x368
FEDERAL ID NO: 93-0643773

INVOICE NUMBER

AR190463

INVOICE DATE

05/22/18

PAYMENT DUE

06/30/18

PORTLAND GENERAL ELECTRIC
ATTN: NATALIA PAVLOVA/JEFF STEVENS
121 SW SALMON ST
ONE WORLD TRADE CTR 5TH FLR (1WTC0501)
PORTLAND, OR. 97204

DESCRIPTION

CHARGES

Energy Resource Supplier Assessment - State Fiscal Year 2018-2019
Calendar year 2017

2,412,208.00

Amount Due

\$ 2,412,208.00

For questions concerning this invoice, call (503) 378-3268.
Please return the remittance copy or include the invoice number on your check stub.

ORS469.421 (11) (B), REQUIRES A PENALTY FEE OF 2% PER MONTH TO BE ASSESSED ON ALL PAST DUE BALANCES

APPROVAL

N/A

FISCAL INFO ONLY

GRANT/PH NO: A01301/70
T CODE: 199 PCA: 93066
AOBJ: 0401

REMITTANCE COPY

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. 060
Dated February 15, 2018**

Request:

For FAS 87 and FAS 106, please provide the estimated effect on the Test Period Net periodic postretirement cost (income) if the discount rate is changed 25 basis points in both directions and expected rate of return is changed 25 basis points in both directions.

Response:

FAS 87

For FAS 87, the 2019 test year cost sensitivity to a +/- 25 basis point change in the discount rate is not symmetrical.

- A 25 basis point increase in the discount rate decreases costs by approximately \$2.1 million.
- A 25 basis point decrease in the discount rate increases costs by approximately \$2.2 million.

The 2019 test year cost sensitivity to a +/- 25 basis point change in the expected rate of return is approximately \$1.5 million (i.e., a 25 basis point increase reduces costs by \$1.5 million, and a 25 basis point decrease increases costs by \$1.5 million).

FAS 106

For FAS 106, the 2019 test year cost sensitivity to a +/- 25 basis point change in the discount rate is not symmetrical.

- A 25 basis point increase in the discount rate decreases costs by approximately \$0.12 million.
- A 25 basis point decrease in the discount rate increases costs by approximately \$0.14 million.

UE 335 PGE Response to OPUC SDR No. 060
February 15, 2018
Page 2

The 2019 test year cost sensitivity to a +/- 25 basis point change in the expected rate of return is approximately \$0.79 million (i.e., a 25 basis point increase reduces costs by \$0.79 million, and a 25 basis point decrease increases costs by \$0.79 million).

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
<hr/>)

EXHIBIT NO. AWEC/308

CENTRAL LINCOLN PEOPLE’S UTILITY DIST.

v.

**OREGON DEPT. OF ENERGY, MARION COUNTY CIR. CT. CASE NO. 16CV18269
(AUG. 9, 2017)**



CIRCUIT COURT OF OREGON
THIRD JUDICIAL DISTRICT
MARION COUNTY COURTHOUSE
P.O. BOX 12869
SALEM, OR 97309-0869

TRACY A. PRALL
Circuit Court Judge
(503) 588-5030
Fax: (503) 588-5109

August 9, 2017

Brad Daniels and
Eric Kodesch
Stoel Rives LLP
760 SW Ninth Ave Ste 3000
Portland OR 97205
VIA EMAIL ONLY

Carla Scott
DOJ Trial Division
100 SW Market St
Portland OR 97201
VIA EMAIL ONLY

Marilyn Harbur
DOJ GC Tax & Finance
1162 Court St NE
Salem OR 97301
VIA EMAIL ONLY

RE: *Central Lincoln People's Utility District, et al v. Oregon Department of Energy, et al*
Marion County Circuit Court Case No. 16CV18269

Counsel,

This matter came before the court on June 29, 2017, for hearing on cross Motions for Summary Judgment. Petitioners appeared by and through counsel, Brad Daniels and Eric Kodesch. Respondents appeared by and through counsel, Carla Scott and Marilyn Harbur. The court reviewed the Motions, Responses, and Replies and heard oral argument. The court then took the matter under advisement.

Now, having fully considered this matter, the court makes the following findings of fact and conclusions of law:

STATEMENT OF FACTS

Central Lincoln People's Utility District, City of Hermiston d/b/a Hermiston Energy Services, Clatskanie People's Utility District, Columbia River People's Utility District, Consumers Power Inc., Emerald People's Utility District, Eugene Water & Electric Board, Northern Wasco People's Utility District, Tillamook People's Utility District, and Umatilla Electric Cooperative (collectively, "Petitioners") are municipal cooperative corporations that qualify as energy resource suppliers. Under ORS 469.421(8)(i)(A), an "energy resource supplier" is, "an electric utility, natural gas utility or petroleum supplier supplying, generating, transmitting or distributing electricity, natural gas or petroleum products in Oregon."

Petitioners bring a claim against the Oregon Department of Energy ("ODOE") and the ODOE director Michael Kaplan (collectively, "Respondents"). The ODOE regulates energy facilities and develops programs and activities to increase energy efficiency. Some of ODOE's public duties include serving as a "central repository...for the collection of data on energy resources," "inform[ing] and educat[ing] the public about energy problems and ways in which the public can conserve energy resources," and "administer[ing] federal and state energy allocation and conservation programs and energy research and development programs." ORS 469.030(2)(a)-(b), (e). To fund those programs and activities, ORS 469.421(8)(a) requires "each energy resource supplier pay to the department annually its share of an assessment to fund the programs and activities of the council and the department," known as the Energy Supplier Assessment ("ESA").

Each petitioner received an Order Determining and Allocating Assessment and Implementing Provisions (collectively "Orders") for the 2016-17 fiscal year. After receiving the Orders, petitioners filed this Petition for Review pursuant to ORS 183.484. Petitioners and respondents filed Cross-Motions for Summary Judgment.

SUMMARY JUDGMENT STANDARD

Under the APA, the court determines whether a final state agency order is supported by substantial evidence and whether the agency has correctly applied the law. ORS 183.484(5). In deciding whether to grant a motion for summary judgment, the appropriate inquiry is whether there is substantial evidence in the record before the circuit court to support the agency's

determination. Where no disputed issues of material fact exist, the court's inquiry is purely legal in nature. ORS 183.484 grants the court authority to:

(5)(a)...affirm, reverse, or remand the order. If the court finds that the agency has erroneously interpreted a provision of law and that a correct interpretation compels a particular action, it shall:

(A) Set aside or modify the order; or

(B) Remand the case to the agency for further action under a correct interpretation of the provision of law.

(b) The court shall remand the order to the agency if it finds the agency's exercise of discretion to be:

(A) Outside the range of discretion delegated to the agency by law;

(B) Inconsistent with an agency rule, an officially stated agency position, or a prior agency practice, if the inconsistency is not explained by the agency; or

(C) Otherwise in violation of a constitutional or statutory provision.

(c) The court shall set aside or remand the order if it finds that the order is not supported by substantial evidence in the record. Substantial evidence exists to support a finding of fact when the record, viewed as a whole, would permit a reasonable person to make that finding. ORS 183.484(5)(a)-(c).

MOTIONS FOR SUMMARY JUDGMENT

On summary judgment, petitioners move the court to: (1) Declare the ESA is a tax; (2) Declare SB 5510 is subject to Oregon constitutional requirements for bills raising revenue; (3) Declare the ODOE and Michael Kaplan did not follow statutory procedures before including the ESA in the agency's 2015-17 budget; (4) Set aside the Orders imposing the 2016 ESA and refund the ESA amounts paid by petitioners; and (5) Enjoin collection of ESA until ODOE complies with the Oregon Constitution and ORS 469.421(8). Respondents move the court to declare, as a matter of law, that the ODOE lawfully issued the ESA to petitioners in 2016.

I. Is the ESA a tax?

Pursuant to ORS 469.421(8)(a), the ODOE mandates each energy resource supplier pay to the department annually its share of an assessment "to fund the programs and activities of the council and the department." The annual assessment is commonly referred to as the ESA. ORS 469.421(8)(a) specifically provides:

"In addition to any other fees required by law, each energy resource supplier shall pay to the department annually its share of an assessment to fund the programs and activities of the council and the department" (emphasis added).

ORS 469.421(8)(a) is nearly identical in language, function, and purpose to an earlier version of the ESA provided for in former ORS 469.420 (1981). Former ORS 469.420(4) provided:

“In addition to any other fees required by law, each energy resource supplier shall pay to the department annually commencing with the fiscal year beginning July 1, 1981, its share of an assessment to fund the activities of the department....” (emphasis added).

In *Northwest Natural Gas Company v. Frank*, former ORS 469.420(4) was declared a tax against energy resource suppliers. *Northwest Natural Gas Company v. Frank*, 293 Or. 374, 376 (1982). In the last sentence of the opinion, the Court ordered the director to “amend his orders to assess **taxes** exclusively on a gross revenue basis.” *Northwest Natural Gas. v. Frank*, 293 Or. at 384. After the opinion, by operation of law, former ORS 469.420 was automatically repealed and ORS 169.421 was enacted.

Respondents’ comparison of the ESA set out in ORS 169.421(8)(a) to former ORS 756.310 is misplaced. The Ninth Circuit Court of Appeals held the “assessment” imposed on railroads by the Oregon Public Utility Commission (“OPUC”) under former ORS 756.310 was a fee not a discriminatory tax for purposes of the federal Railroad Revitalization and Regulatory Act (4-R Act). *Union Pacific Railroad Company v. Public Utility Commission of the State of Oregon*, 899 F.2d 854, 856 (9th Cir. 1990). The assessment was paid directly to the OPUC and did not go into the general fund, generating no profit but devoted exclusively to defraying the costs of the regulatory program itself. *Id.* at 856-57. Similar to ORS 756.310, ORS 169.421(2) through (7) are devoted exclusively to defraying the costs of the regulatory programs. Specifically, subsection (7) provides:

“When the actual costs of regulation incurred by the council and the department for the year, including that portion of the general regulation costs that have been allocated to a particular facility, are projected to exceed the annual fee for that facility, the director may issue an order revisiting the annual fee” (emphasis added).

However, subsection (8) is not devoted exclusively to defraying the costs of the regulatory programs, it is devoted to defraying the costs of the “programs and activities of the council and the department.” By the clear language of the statute, the legislature intended for subsection (8) to cover costs other than regulatory costs.

The Oregon Supreme Court two-part test for determining whether a bill qualifies as a bill for raising revenue: (1) whether the bill collects or brings money into the treasury; and (2) whether the bill possesses the essential features of a bill levying a tax. *Bobo v. Kulongoski*, 338 Or. 111, 122, 107 P.3d 18, 24 (2005). The court finds ORS 169.421(8)(a) is a tax. The court also finds that ORS 169.421(8) correctly originated in the House of Representatives as HB 2259 and the amended HB 2807 (2013). Therefore, ORS 169.412 (8) does not violate the Oregon constitutional requirements for bills raising revenue.

(2) Is SB 5510 subject to Oregon constitutional requirements for bills raising revenue?

In 2015, the Oregon Legislative Assembly Regular Session passed Senate Bill 5510 that limits biennial expenditures from fees, moneys or other revenues, including Miscellaneous Receipts, but excluding lottery funds and federal funds, collected or received by State Department of Energy. *SB 5510*, 78th Gen. Assembly, Reg. Sess. (2015). Section 1 declares “\$47,888,133 is established for the biennium beginning July 1, 2015, as the maximum limit for payment of expenses from fees...collected or received by the State Department of Energy” and Section 3 declares “\$3,091,351 is established for the biennium beginning July 1, 2015, as the maximum limit for payment of expenses from federal funds collected or received by the State Department of Energy.” *Id.*

The court finds SB 5510 is a budget bill for the 2015-17 biennium because it raises no revenue but authorizes expenditures. Also, SB 5510 transfers money between programs not “collect[ing] or bring[ing] money into the treasury.” *Bobo v. Kulongoski*, 338 Or. at 122, 107 P.3d at 24. Therefore, SB 5510 is not subject to Oregon constitutional requirement that bills raising revenue originate in the House of Representatives.

(3) Did ODOE and Michael Kaplan follow statutory procedures before including the ESA in the agency’s 2015-17 budget?

In 2013, the Oregon Legislative Assembly amended ORS 469.421 to include a new subsection regarding the ESA, subsection (8)(b) which provides:

“Prior to filing an agency request budget under ORS 291.208. for purposes related to the compilation and preparation of the

Governor's budget under ORS 291.216, the director shall determine the projected aggregate amount of revenue to be collected from energy resource suppliers under this subsection that will be necessary to fund the programs and activities of the council and the department for each fiscal year of the upcoming biennium. After making that determination, the director shall convene a **public meeting** with representatives of energy resource suppliers and other interested parties for the purpose of providing energy resource suppliers with a **full accounting** of:

(A) The projected revenue needed to fund **each department program or activity**; and

(B) The projected allocation of moneys derived from the assessment imposed under this subsection to **each department program or activity.**"

ORS 469.421(8)(b) (emphases added).

In this matter, the ODOE convened four meetings in 2014, but none pursuant to the public meeting laws set out in ORS 192.630-640(1). The first meeting on May 19, 2014, called the "Energy Advisory Work Group", was an overall retrospective review of department policies, plans, and activities but did not specifically provide an accounting of the projected revenue needed or the projected allocation of the monies derived from the assessment. The second meeting on August 5, 2014 and the third meeting on August 7, 2014 were about budget information; however, both meetings lacked representatives of energy resource suppliers and other interested parties as mandated by ORS 469.421(8)(b). The fourth meeting on September 2, 2014, called the "Energy Advisory Work Group" was similar to the first meeting on May 19, 2014.

The first statutory violation the plaintiffs ask the court to consider is whether ODOE was required to and failed to hold a "public meeting" as that term is defined by ORS 192.630-640. Oregon's Public Meeting Laws define a "meeting" as "the convening of a governing body of a public body for which a quorum is required in order to make a decision or to deliberate toward a decision on any matter." ORS 192.610(5). Where no decision or deliberation takes place, there is no basis for calling an interaction a public meeting subject to the notice requirement. *See Handy v. Lane County*, 274 Or. App. 644, 661 (2015). A "governing body" is "any public body which consists of two or more members, with the authority to make decisions for or recommendations to the public body on policy or administration." ORS 192.610(3). A "decision" is "any

determination, action, vote or final disposition upon a motion, proposal, resolution, order, ordinance or measure on which a vote of a governing body is required, at any meeting.” ORS 192.610(1). The ESA meetings from 2014 were to provide energy resource suppliers with information. A meeting that facilitates information gathering is not, by itself a public meeting. *Harris v. Nordquist*, 96 Or. App. 19, 25 (1989). Thus, the 2014 meetings were not within the definition of requiring a governing body to make a decision but informational meetings pursuant to ORS 469.421(8).

Additionally, according to the *Attorney General's Public Records and Meetings Manual*, “The Public Meetings Law applies to the meetings of the governing body of public body... A ‘public body’ is also a board, department, commission, council, bureau, committee, subcommittee or advisory group.” (*Attorney General's Public Records and Meetings Manual – Governing Bodies of Public Bodies* (November 2014) § II.B.1). More importantly, “a department headed by an individual public officer, such as the office of the State Treasurer, is not a ‘governing body.’” *Id.* Here, the ODOE is a public body. The ODOE is headed by Michael Kaplan. As the director, Mr. Kaplan is not a governing body; therefore the Public Meetings Law is not applicable to ORS 469.421(8)(b).

The second violation the plaintiffs ask the court to consider is whether ODOE provided a “full accounting” to representatives of energy resource suppliers and other interested parties as required by the statute. On this point the court finds there is no genuine issue of material fact. Despite holding four separate meetings in 2014 and claims that a “full accounting” was provided, at no time did ODOE provide the full accounting required by ORS 469.421(8)(b). ODOE erroneously interpreted this provision of the law. ODOE failed to specifically provide the representatives of energy resource suppliers and other interested parties the projected revenue needed to fund each department program or activity and the projected allocation of monies derived from the assessment imposed under this subsection to each department program or activity. Therefore, the court finds ODOE failed to follow statutory procedures before including the ESA in the agency’s 2015-17 budget. The court must assume that the legislature intended to give full effect to each statutory provision. ODOE’s failure to provide the full accounting required by ORS 469.421(8)(b) deprived the representatives of energy resource suppliers and other interested parties of information the legislature intended them to have so that they could

fully and effectively engage in the legislative process. There is no remedy that would adequately address ODOE's failure other than setting aside the Orders imposing the 2016 ESA.

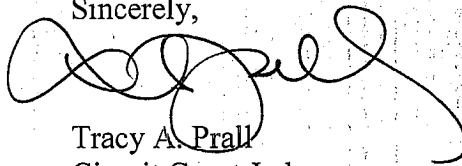
CONCLUSION

Plaintiffs' Motion for Summary Judgment is **GRANTED** in part. Respondents' Motion for Summary Judgment is **DENIED**.

- The court declares the ESA is a tax.
- The court declares SB 5510 is not subject to Oregon constitutional requirements for bills raising revenue.
- The court declares the ODOE and Michael Kaplan did not follow statutory procedures before including the ESA in the agency's 2015-17 budget. Pursuant to ORS 183.484, the court finds that the ODOE erroneously interpreted a provision of law and that a correct interpretation compels the court to set aside the Orders imposing the 2016 ESA. Therefore, the ESA amounts paid by petitioners shall be refunded.
- Pursuant to ORS 183.484, the court lacks authority to issue an order enjoining collection of future ESAs.

Mr. Daniels shall prepare an appropriate order and judgment within 14 days for opposing counsel's review. There are no future dates set in this matter.

Sincerely,



Tracy A. Prall
Circuit Court Judge

TAP:cdh

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UE 335

In the Matter of)
)
PORTLAND GENERAL ELECTRIC)
COMPANY,)
)
Request for a General Rate Revision.)
<hr/>)

EXHIBIT NO. AWEC/309

EXCERPT OF ODOE ESA POWERPOINT

2017-19 PROGRAM BUDGET ALLOCATIONS WITH PACKAGES

8/13/2016

	Base	Essential	Current Service Level		Policy Option	ESA in Packages		Agency Request Budget			
	Budget	Packages	CSL	CSL ESA	Packages	Pkg 07D	Pkg 11D	ARB	ARB ESA	FTE	FTE ESA
PUBLIC SCHOOLS	\$1,114,826	\$10,806	\$1,125,632	\$174,526				\$1,125,632	\$174,526	3.18	0.43
PUBLIC BUILDINGS	\$1,328,029	\$12,665	\$1,340,694	\$779,451	\$77,393			\$1,418,087	\$779,451	3.92	2.08
ENERGY EFFICIENCY & CONSERVATION	\$1,067,800	\$10,668	\$1,078,467	\$860,002	(\$77,393)		(\$77,393)	\$1,001,074	\$782,609	2.37	1.83
RENEWABLE TECHNOLOGIES	\$2,060,564	\$166,552	\$2,227,116	\$2,198,753				\$2,227,116	\$2,198,753	6.06	6.06
TRANSPORTATION	\$790,144	\$7,374	\$797,518	\$790,918	(\$164,480)		(\$164,480)	\$633,039	\$626,439	1.33	1.33
PLANNING, ECONOMICS & OTHER	\$1,150,481	\$59,309	\$1,209,790	\$1,197,117				\$1,209,790	\$1,197,117	3.09	3.09
SELP LOAN ACTIVITY	\$118,981,555	\$0	\$118,981,555					\$118,981,555	\$0		
SELP ADMINISTRATION	\$2,688,081	(\$29,471)	\$2,658,610		(\$118,220)			\$2,540,390	\$0	7.64	
CLEAN ENERGY DEPLOYMENT FUND	\$1,227,760	\$45,427	\$1,273,187					\$1,273,187	\$0		
EEAST DEBT SERVICES	\$3,023,630	\$0	\$3,023,630					\$3,023,630	\$0		
ALT FUEL VEHICLE LOAN PROGRAM	\$1,007,661	\$37,511	\$1,045,172					\$1,045,172	\$0		
ENERGY INCENTIVE PROGRAM	\$4,904,490	(\$618,889)	\$4,285,601		\$2,000,000			\$6,285,601	\$0	4.81	
BIOMASS TAX CREDITS	\$406,172	(\$254,420)	\$151,752	\$5,000				\$151,752	\$5,000	0.59	
BUSINESS ENERGY TAX CREDITS	\$380,326	(\$215,391)	\$164,935	\$2,000				\$164,935	\$2,000	0.54	
RESIDENTIAL ENERGY TAX CREDIT	\$859,336	(\$130,476)	\$728,859	\$447,837				\$728,859	\$447,837	3.25	1.82
STATE HEATING OIL WEATHERIZATION PROGRAM	\$717,528	\$16,024	\$733,552					\$733,552	\$0	0.27	
HANFORD OVERSIGHT	\$1,903,256	\$15,933	\$1,919,190					\$1,919,190	\$0	3.80	
EMERGENCY PREPAREDNESS	\$783,136	\$6,610	\$789,746	\$173,149				\$789,746	\$173,149	1.58	0.40
RADIOACTIVE WASTE TRANSPORTATION	\$166,950	\$2,002	\$168,952					\$168,952	\$0	0.25	
SITING CERTIFICATION	\$3,346,109	\$67,288	\$3,413,397					\$3,413,397	\$0	4.46	
SITE CERTIFICATION MONITORING	\$416,998	\$0	\$416,998					\$416,998	\$0	1.10	
FEDERAL SITING COORDINATION	\$5,829	\$0	\$5,829	\$5,829				\$5,829	\$5,829	0.11	0.01
ENERGY FACILITY SITING COUNCIL	\$2,210,241	\$7,611	\$2,217,852	\$594,169	\$202,097			\$2,419,949	\$594,169	6.33	1.38
DIRECTOR'S OFFICE	\$4,839,713	(\$775,629)	\$4,064,084	\$4,187,493	\$250,000			\$4,314,084	\$4,187,493	8.52	8.52
CENTRAL SERVICES	\$6,443,114	\$2,226,356	\$8,669,470		\$819,073			\$9,488,543	\$0	28.45	
OTHER ADMINISTRATIVE SERVICES	\$729,410	\$1,075	\$730,485		\$502,617			\$1,233,102	\$0	3.00	
NON PROGRAM SPECIFIC FUNCTIONS											
Energy Planning & Innovation	\$2,656,706	\$57,762	\$2,714,467	\$1,337,111	(\$1,147,890)			\$1,566,577	\$1,337,111	3.30	3.30
Energy Development Services	\$2,191,747	(\$628,016)	\$1,563,732	\$549,420	(\$118,220)	(\$118,220)		\$1,445,512	\$431,200	0.73	0.73
Nuclear Safety & Emergency Preparedness	\$376,486	(\$47,525)	\$328,961	\$176,855	(\$135,000)			\$193,961	\$176,855	0.37	0.37
Energy Facility Siting		\$0	\$0					\$0	\$0		
Administrative Service:	\$1,667,023	(\$681,901)	\$985,121		(\$655,752)			\$329,369	\$0		
Total (includes indirects)	\$169,445,102	(\$630,745)	\$168,814,357	\$13,479,632	\$1,434,225	(\$282,700)	(\$77,393)	\$170,248,582	\$13,119,539	99.04	31.34