ORDER NO. 15-356

ENTERED: NOV 03 2015

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 294

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

DISPOSITION: STIPULATIONS ADOPTED; APPLICATION FOR GENERAL RATE REVISION APPROVED AS REVISED, SUBJECT TO TRUE-UP

I. SUMMARY

Portland General Electric Company (PGE) seeks an overall revenue increase of $66 million (3.7 percent).[1] In this order, we adopt proposed settlements to resolve all issues related to the request and authorize an overall rate increase of 1 percent, or $17.8 million in additional revenues. Effective January 1, 2016, bills will increase on average by 0.6 percent for residential customers and 2.0 percent for commercial and industrial customers.[2]

II. BACKGROUND AND PROCEDURAL HISTORY

PGE is a public utility providing electricity service within the meaning of ORS 757.005, and is subject to our jurisdiction with respect to the prices and terms of service for its Oregon retail customers.

On February 12, 2015, PGE filed Advice No. 15-02 to increase overall rates by 3.7 percent to produce additional revenues of $66.2 million. PGE seeks the increase to recover increased business expenses and costs associated with the addition of the Carty Generating Station (Carty).

On February 20, 2015, we suspended PGE's tariff filing for a period of nine months as authorized by ORS 757.215.[3] During the course of the proceedings, the following were granted leave to intervene as parties: the Industrial Customers of Northwest Utilities (ICNU); Noble Americas Energy Solutions LLC; Fred Meyer Stores and Quality Food Centers, Divisions of Kroger Co. (Kroger); PacifiCorp, dba Pacific Power; NW Energy Coalition (NWEC); and the

[1] PGE's filing also included a request to recover net variable power costs (NVPC).
[2] These amounts will be subject to a true-up to reflect the changes to PGE's NVPCs as well as PGE's subsequent final MONET update.
[3] *See* Order No. 15-052.

Small Business Utility Advocates (SBUA). The Citizens' Utility Board of Oregon (CUB) intervened as a matter of right under ORS 774.180.

On May 18, 2015, we held a public comment hearing at the Portland Central Library. Members of the public and representatives from a variety of customer and community groups were given the opportunity to comment on the proposed increase in PGE' s rates. Representatives from PGE, CUB, and the Community Action Partnership of Oregon were available to answer questions and provide information. In addition, there was the opportunity to make comments via e-mail, U.S. Mail, and telephone.

The parties conducted discovery, filed several rounds of testimony, and engaged in settlement discussions. All issues were all ultimately resolved by the parties. A partial stipulation was filed on June 23, 2015. The parties state that subsequently, all power cost issues except one, and all revenue requirement issues were settled on July 8 and 9, 2015, subject to satisfactory settlement of rate spread and rate design issues. On July 17, 2015, the parties settled all rate spread and rate design issues, except for one power cost issue. Through the execution of a second partial stipulation, that issue was settled as well. The terms of settlement for all of the issues resolved subsequent to the first stipulation, including the process for updating of the cost of debt, were set forth in the second stipulation, filed on August 28, 2015. Each stipulation was supported by joint testimony. In addition, Staff filed testimony in support of the partial stipulation. No party opposes either of the stipulations.[4] The stipulations are attached to this order as Appendices A and B.

III. DISCUSSION

The parties were able to settle all issues in the proceeding. We outline the nature of each partial stipulation and summarize each initially disputed issue that was the subject of the negotiated settlement in that stipulation.

A. Partial Stipulation

The first partial stipulation addresses most of the issues relating to PGE's general revenue requirement. It was entered into by PGE, CUB, ICNU, Kroger, and Staff. SBUA participated in discussions, but was not a signatory. No party to the proceeding opposed the stipulation.

Those issues are as follows

1. Revenue Requirement Operations and Maintenance (O&M) Expense

a. Issue S-1: Uncollectible Rate

In its initial filing, PGE included a 0.4300 percent rate for uncollectible revenue. The stipulating parties agree that PGE will use a 0.4032 percent uncollectibles rate to reflect Staff's analysis

[4] The Commission Staff, CUB, ICNU, Kroger, and PGE were signatories to the stipulations. NWEC and SBUA, while not parties to the stipulation, did not interpose any objection to them.

calculating the three-year average of actual net write-offs, but did not agree to a specific reduction in uncollectible expense for the test year.[5]

b. Issue S-5: Advertising Costs

Staff conducted a detailed review of the company's test year advertising costs and proposed that certain costs in FERC account 908 be removed for lack of justification. Based on the parties' agreement, O&M costs related to advertising were reduced $70,000, due to the exclusion of Institutional/Promotional, Political/Non-Utility Advertising and Energy Efficiency/Conservation Advertising.[6]

c. Issue S-7: Medical Benefits

Staff analyzed PGE's medical benefits historical trends and the trends in comparable industries. Based on Staff's review, the parties agree to reduce non-union medical benefit expense by $577,000 and union medical benefit expense by $320,000. For settlement purposes, the parties also agree to remove $95,000 in expenses related to the company's biennial picnic.[7]

d. Issue S-9: Dues and Donations

Staff reviewed costs associated with PGE memberships in specific organizations and the parties agree to reduce the company's test year O&M expenses by $194,000.

e. Issue S-10: Capital Additions

Two capital projects are covered by the stipulation: the North Fork Surface Collector (NFSC) and the Grassland Switchyard (GS).

The NFSC is a hydro licensing requirement included in the FERC license for the Clackamas Hydro Project. PGE expects the collector to be operational this fall (2015). Because PGE's test year rate was established as of December 31, 2015, the parties agree that when the NFSC project is placed into service, PGE will file an attestation to that effect. If the plant is not in service by year-end, it will be removed from the test-year rate base. The costs included in the rate base will be the lesser of actual project costs or $53.8 million. If the costs exceed that amount, PGE will not be bound by its original estimate in subsequent rate proceedings, but will need to demonstrate prudence of expenditures in excess of $53.8 million.[8]

GS is a switchyard to be built to integrate the Carty plant into the existing Boardman-Slatt transmission line. Staff evaluated GS as part of the Carty review and found the investment to be prudent. However, the parties agree to remove the $24.7 million net amount for GS from the rate

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[5] Stipulating Parties/100, Gardner-Jenks-Mullins-Townsend-Tooman/4.
[6] *Id.*
[7] *Id.* at 5.
[8] *Id.* at 5-6.

base and have it remain in construction work in progress until Carty is placed into service in 2016.[9]

f. Issue S-12: Energy Efficiency and Demand Side Management Programs

The parties agree to reduce PGE's O&M costs by $237,000 based on Staff's review of historical actual costs and a comparison of test year program costs with tariffed programs and planned pilots.

g. Issue S-13: Research and Development

The parties agree to reduce test period R&D costs from $3.1 million to $2.0 million. The $2.0 million reflects $1.4 million in carryover projects from 2014 to 2015, and an additional $0.6 million for smart grid and energy storage programs. In reaching a settlement on this issue, the parties agree to certain conditions with respect to PGE's next general rate case filing:

- PGE will file annual reports of R&D spending.
- There will be no prudence review associated with these annual filings.
- If PGE's R&D spending is less than $2.0 million per year, the unspent amount will be refunded to customers.[10]

h. Miscellaneous Adjustments

In lieu of assigning particular dollar amounts to adjustments in each of these revenue requirement-related issues, the parties collectively resolved them with an $8.0 million reduction to PGE's test year O&M expenses and a $9.0 million reduction to PGE's test year rate base. The components to the group settlement were as follows:

- In Issue S-4, Wages and Salaries, the parties examined Staff's wage and salary model and appropriate escalation factors, the bases for specific increases in the number of full-time employees, percentage disallowances for various categories of incentives and appropriate rates of increase in overtime.
- In Issue S-6, A&G, the parties addressed, in particular, business meals and entertainment, employee recognition, union meals and incidentals, and director and officer (D&O) insurance and the appropriate percentages of these costs to include in the revenue requirement. In particular, the parties addressed to which layers of D&O insurance, expenses should be disallowed.
- In Issue S-8, Pension costs, the parties discussed the appropriate discount rate applicable to the company's FAS 87 pension expense and the appropriateness of including PGE's pension deferred tax liability in rate base.

[9] *Id.* at 6.
[10] *Id.* at 6-7.

- Issue S-11, Escalation, relates to the reasonableness of various factors used to escalate PGE's non-labor-related expenses and the appropriateness of using a single factor versus using different factors that relate to specific types of costs.
- Issue S-13, Fee Free Bankcard (FFBC), program addresses all issues related to the program and reflects discussions on projected participation rates, how those rates are determined and how much the rates would increase. The parties agree that PGE would not launch a commercial FFBC program in 2016 and would notify Staff no less than forty-five days before launching a commercial FFBC payment program.[11]

i. Issue I-7: Coal Inventory

Based on discovery by the parties, they agree that, for purposes of settlement, no adjustment is necessary to PGE's test year revenue requirement.[12]

2. Non-Revenue Requirement Issues

a. Issue I-2: Construction Overheads

This issue relates to PGE's methodology for allocating construction overheads to capital projects. Staff raised concerns with respect to PGE's methods, now based solely on labor, the ratio of overhead costs to direct labor costs for certain construction projects, and the trade-off between allocations and direct charges. The parties agree that PGE will hire an outside expert to review those allocations and methodologies to determine if PGE's methods readily identify the source of expenses and the bases for their allocation. PGE, Staff, and the other parties will collaborate on the expert selection process and will receive a copy of the expert's report.[13]

b. Issue I-3: Prudence of Carty Investment

Staff conducted a detailed prudence review of the Carty plant from two perspectives. First, the Carty plant investment was examined with respect to consistency with previous integrated resource plans (IRPs) and requests for proposal (RFPs). Secondly, Staff explored the question of whether the Carty plant was a prudent investment on the date PGE decided to proceed with the project. Staff concluded that Carty was consistent with previous IRPs and RFPs and was a prudent investment as of June 3, 2013, the date PGE decided to proceed with the project. The stipulating parties therefore agree for the purposes of settlement that the Carty plant was prudent and that the Commission should approve the tariff rider subject to the following conditions:

- For rates determined in this docket only, the gross plant for Carty, including GS, will be \$514 million. If the actual capital costs are lower, PGE will refund the 2016 revenue requirement differences resulting from lower capital costs.
- The parties ask for Commission approval of specific accounting language for treatment of GS capital costs. The parties agree to remove \$24.686 million from PGE's 2015 rate

[11] *Id.* at 7-8.
[12] *Id.* at 11.
[13] *Id.* at 9.

base and construction work in progress will continue to accrue until Carty is placed in service.

- If Carty capital costs exceed $524 million, PGE may not recover those costs through the tariff rider, but the company will not be bound to that number in future rate proceedings, although it will have to demonstrate prudence for such additional costs.

PGE will file an attestation by an officer when Carty is placed in service. However, if Carty is not completed and in service by July 31, 2016, PGE will need to file a new ratemaking request to include Carty and GS in rates.[14]

B. The Second Partial Stipulation

The second partial stipulation, filed on August 28, 2015, was entered into by PGE, CUB, ICNU, Kroger, and Staff. The SBUA participated in discussions, but was not a signatory. No party to the proceeding opposed the stipulation.

1. Issues S-0, S-3, and CUB-7: Cost of Capital

In its direct testimony, PGE requested a 7.677 percent cost of capital for the 2016 test year, which included a 9.9 percent authorized rate of return on equity (ROE) and a 5.433 percent cost of long-term debt and a 50-50 percent debt-to-equity capital structure. Staff proposed a 7.198 percent cost of capital which included a 9.160 percent authorized ROE, a 5.235 percent cost of long-term debt and a 50-50 percent capital structure. ICNU proposed a 7.34 percent cost of capital which included a 9.25 percent authorized ROE, a 5.43 percent cost of long-term debt and a 50-50 percent capital structure. CUB recommended a 55-45 percent capital structure or, alternatively, a 2 percent reduction in the authorized rate of return. In the interest of settlement, the parties agree to reduce the revenue requirement by $4 million for all of the revenue requirement issues including the cost of capital, as well as a 9.6 percent return on equity and 50 percent debt-50 percent equity capital structure.[15]

2. Issues I-4, I-6, ICNU-2, and ICNU-3: Marginal Cost of Service

Several issues were identified relating to the marginal cost of service. Staff (Issue I-4) proposed that the costs of Port Westward 2 be included as an energy cost for the purpose of integrating wind generation, arguing that "[any dollar-per-kilowatt] cost assigned to supplying wind power should be considered as an energy cost."[16] PGE proposed using the Bonneville Power Administration's Variable Energy Resource Balancing Service tariff as a capacity cost to integrate wind generation.

Staff (Issue I-6) proposed an adjustment to the marginal cost of billing based on reduced postage costs due to a greater incidence of paperless billing than projected by PGE in its direct testimony.

[14] Stipulating Parties/100, Gardner-Jenks-Mullins-Townsend-Tooman/10-12.
[15] Stipulating Parties/200, Gardner-McGovern-Mullins-Townsend-Wenzel/5. The cost of debt will be updated by actual debt issuances by PGE that occur no later than November 1, 2015.
[16] Staff/400, Bhattacharya/3.

ICNU (Issue ICNU-2) proposed that a more flexible capacity resource such as Port Westward 2 be used in determining the marginal generation capacity costs. PGE had proposed using a lower cost, less flexible capacity resource for estimating the marginal capacity cost of generation.[17]

Parties also proposed that the marginal cost of energy be reduced because of dispatch margins that could accrue to the baseload resource and proposed, for the sake of consistency, that PGE should include fixed pipeline costs for the capacity resource when calculating the capitalized costs of energy.

To resolve these issues as part of an overall settlement, the parties agree to Staff's position for calculating the marginal generation costs, and agree to use PGE's marginal capacity resource as the basis for marginal capacity costs. The parties also agree to Staff's adjustment to billing which used a trend analysis to determine the projected number of customers who enroll in paperless bills for the test period; the adjustment has a minor impact on the marginal costs of billing customers and did not impact the revenue requirement. Similarly, in the interest of settlement, the parties agree not to incorporate ICNU's proposed margin adjustment to the marginal costs but agree to ICNU's proposed adjustment to include the fixed pipeline costs of the marginal capacity resource when calculating the capital costs that are classified as energy.[18]

3. Issue I-5: Load Forecast

Staff was the only party to make recommendations regarding PGE's load forecast. Staff recommended that:

- PGE should exclude the price adjustment to the non-residential energy forecast for this proceeding.
- Staff should work with PGE to identify alternative methods for addressing energy efficiency in the load forecast.
- PGE should use an alternative set of residential load forecast regression models which incorporate real average price in the regression equations, rather than using PGE's price elasticity approach. Staff did not place a dollar amount on the effect of this change.

In settlement of all load forecast issues, the parties agree that

- PGE will exclude the price adjustment in the residential and non-residential load forecast in this rate case.
- PGE will work with Staff to compile an historical series of achieved energy efficiency with a goal of compiling data at the most reasonable disaggregate level and will work with Staff to consider alternative forecasting modeling methods that incorporate energy efficiency.
- PGE will work to increase Staff's and other parties' understanding of PGE's load forecasting model.[19]

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[17] Stipulating Parties/200 at 6-7.
[18] *Id.* at 6-8.
[19] *Id.* at 8-9.

- If PGE's load forecasting model in a subsequent docket explicitly includes a price effect, PGE agrees to work with the other parties to evaluate models that incorporate a marginal price variable into the base forecast.

4. Issue I-8: Portfolio Options

Staff questioned whether PGE's voluntary renewables portfolio options program participants were bearing their appropriate share of the program's costs or if non-participating customers were subsidizing the program. The program included various back office support costs as well as direct costs of acquiring renewable energy certificates (REC) and managing the program. Staff also questioned program development and marketing costs that were allocated to all eligible customers. Staff proposes that the company conduct a review of its portfolio options costs and that, if the amounts collected did not reasonably match the costs incurred, appropriate program and tariff changes should be made. Additional reviews should be performed periodically by the company.

PGE agrees to conduct an audit of portfolio options costs and participating customer contributions and agrees to work with Staff and other interested persons as well as the Commission's Portfolio Option Committee (POC) and to present its results to Staff and the POC by November 2015 and make any appropriate changes. Similar audits, with adjustments if necessary, will take place every three years on a going-forward basis.[20]

5. Issue I-10: Tariff Schedule 300 Non-Network Meter Charges

Staff questioned whether tariff Schedule 300 charges for installing and reading non-network meters levied on customers who opt out of PGE's advanced metering infrastructure, were too high and not cost-based. In seeking information from PGE, Staff noted that the Commission's Consumer Services Section had received customer complaints about the opt-out option's cost, as had CUB, with respect to the one-time installation charge.

In response, the parties agree that Schedule 300 charges for installing and reading non-network meters will be updated in PGE's compliance tariff filing. The current one-time installation charge of $254.00 will be reduced to $100.00 and the monthly charge for meter reading will be reduced from $51.00 to $45.00. To save costs, the non-network meters will not be capable of recording and storing customer interval load data. As a result, customers opting for a non-network residential meter will not be eligible for time-of-use rates.[21]

6. Miscellaneous Revenue Requirement and Power Cost Issues

Staff and other parties raised numerous issues regarding PGE's revenue requirement and power costs. The revenue requirement issues, both of which were settled by the stipulation, are as follows:

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[20] *Id.* at 9-10.
[21] *Id.* at 11-12.

- CUB-3. CUB raised concerns regarding under-forecasting of Other Revenues. CUB performed a detailed evaluation of the company's actual Other Revenue against budgeted/forecast amounts from 2006 through 2014. Although PGE did not agree with all of the assumptions used in the CUB analysis, the parties agree to increase PGE's test year forecast of Other Revenue by $1.5 million.

- ICNU-1. ICNU proposed reductions to PGE's rate base after a review of its capital additions, comparing the costs to historical levels of expenditure. Based on additional information provided by the company, the parties agree to reduce PGE's rate base by $18.7 million to effectively account for capital projects no longer expected to be operational by year-end 2015.[22]

The following power cost issues raised by Staff, CUB, and ICNU were all addressed and settled by the stipulation, with a single power cost forecast downward adjustment of $7.5 million[23] and two follow-up conditions discussed below:

- PC-1. Staff proposed a collar method to be applied to PGE's Coyote Springs plant similar to that used for excluding outliers from coal plants' forced outage rates.
- PC-2. Staff, CUB, and ICNU proposed to have PGE remove the Super Peak energy purchase from its 2016 power cost forecast.
- CUB-8. CUB questioned the amount of benefit from Carty in PGE's 2016 forecast based on the plant's projected on-line date.
- CUB-9. CUB questioned the recovery of the wind forecasting error based on the potential for double counting.
- CUB-10. CUB questioned whether PGE should analyze using sales for resale to reduce fixed costs by offsetting rate base.
- ICNU-7. ICNU proposed a reduction to PGE's power costs resulting from the economic benefits of access to the California-Oregon border market prices versus historical Mid-Columbia market prices.
- ICNU-8. ICNU questioned PGE's load net wind reserves calculations and proposed updating the forecasting model to reflect the changed reserve formula.
- Staff and ICNU also recommended denying PGE's request to increase the planned maintenance outage to include in the 2016 power cost forecast for Port Westward I from 20 to 79 days.

The two follow-up conditions are, first, that PGE will propose a method for forecasting California trading margins in its next (April 1, 2016) Annual Power Cost Update filing and tariff Schedule 125. Second, the parties ask the Commission to open a docket to address the forecasting of forced outage rates for natural gas generating plants, specifically whether there

[22] *Id.* at 12-13.

[23] The parties specified that the adjustment includes the planned maintenance for Port Westward I in the 2016 power cost forecast, consistent with the forecast included in PGE's April 1, 2015 MONET update. The parties agree that doing so reasonably addresses all of the power cost issues. *Id.* at 14.

should be limits on the length of historical forced outages included in the four-year rolling average.[24]

7. *Issue CUB-6: Power Cost Adjustment Mechanism (PCAM)*

CUB proposed updating the PCAM's power cost deadbands to $60 million above forecasted costs and $30 million below forecasted costs, to reflect the increased size of PGE's rate base. As part of the settlement, the parties agree not to change the current deadbands in Schedule 126, but no party will be precluded from raising the issue in subsequent proceedings.[25]

8. *Rate Spread and Rate Design*

PGE had proposed an allocation of its transmission revenue requirement based on each of the twelve monthly coincident peaks. Staff (I-1) and CUB (CUB-4) proposed different methods to allocate PGE's transmission revenue requirement. Staff proposed an allocation based 75 percent on the January, July, August, and December coincident peaks and 25 percent based on energy. CUB proposed a 65-35 percent allocation. In the interest of settlement, Staff's proposal was adopted.[26]

Several approaches were raised with respect to the optional irrigation Schedules 47 and 49. Staff disagreed with the company's proposal to price the optional irrigation Schedules 47 and 49 in a manner that will facilitate future consolidation into Schedules 32 and 38, respectively, because these schedules have significant cost differences and it would result in greater price increases in Schedules 32 and 38 than would otherwise occur. This would, in Staff's view, result in inequities to Schedule 32 and 38 customers that outweigh any cost savings occurring from an eventual rate consolidation.

Staff proposed to cap the rate increase of Schedules 47 and 49 at 12.5 percent before inclusion of Carty. ICNU (ICNU-6) proposed to cap the rate increase at 12 percent after including Carty. PGE proposed consolidating Schedule 47 into Schedule 32 and capping the rate increase at 12 percent for the consolidated Schedules 38 and 49.

The parties agree that PGE will not price the schedules in a manner that presumes consolidation, resolving the issue by acknowledging the impacts and making various adjustments to the schedules which resulted in reducing the rate increase burden on Schedule 32, relative to PGE's original proposal. PGE also agrees to work with SBUA (SBUA-1) to understand rate impacts for its customer class.[27]

[24] *Id.* at 13-14.
[25] *Id.* at 15.
[26] *Id.* at 17.
[27] *Id.* at 16, 18, 22.

Staff (I-1) and CUB (CUB-5) disagreed with PGE's proposal to raise the Schedule 7 monthly basic charge from $10.00 per month to $11.00 per month. The parties agree to a $10.50 per month basic charge for the purposes of settlement.[28]

Staff (I-9) stated that it would prefer PGE not accelerate the U.S. Department of Energy refund because of rate impacts that will occur January 2017 when the amortization of the refund is complete. Staff endorsed the plan originally proposed in docket UE 283 to spread out the refund over the 2015-2017 period. The parties agree to amortize the credit over the three-year period, but with timing and other changes that would minimize the overall rate impacts.[29]

CUB (CUB-2) raised concerns about the inclusion of the Residential Exchange Credit in determining whether a rate class should contribute to the burden of mitigating the rate increase for the irrigation Schedules 47 and 49. The parties agree with CUB that it would be inappropriate to have the credit contribute to mitigating the irrigation rate increase.[30]

ICNU (ICNU-4) opposed PGE's proposal to allocate the costs of the Schedule 90 load following credit to Schedule 89, believing that the cost of the load following credit should be allocated to all cost-of-service (COS) customers, as was done in previous rate cases. The parties agree that a portion of the credit equal to the amount in current prices should be allocated to all COS customers. To equalize the price impacts for Schedules 89 and 90 primary voltage customers, the parties agree that the load following credit should be increased to $2.00/MWh, with the cost increment above that contained in current rates allocated to Schedule 89 COS customers. The parties also agree to examine this issue in PGE's next general rate case through its marginal cost of service study.[31]

ICNU (ICNU-5) objected to PGE-proposed changes to a special condition in Schedules 75 and 575, Partial Requirements Service, arguing that PGE should be required to provide notice to a partial requirements customer before proposing a change in their baseline demand. ICNU also proposed an increase in the reservation payments to customers who participate in Schedule 77. In the interest of settlement, PGE agrees to ICNU's proposed modifications in Schedules 75 and 575 and ICNU agrees not to pursue its proposed changes to the Schedule 77 reservation payments.[32]

ICNU (ICNU-6) proposed an alternative method of allocating the franchise fee requirement, basing the fees on functionalized distribution and transmission revenue requirements rather than PGE's method which included generation and customer service revenue requirements. ICNU agrees, in the interest of the overall settlement, not to pursue the issue.[33]

Kroger (Kroger-1) proposed that, PGE, in its next general rate case, evaluate the costs of maintaining secondary conductors and how that maintenance cost should be allocated.

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[28] *Id.* at 19.
[29] *Id.* at 19-20.
[30] *Id.* at 16, 20.
[31] *Id.* at 20-21.
[32] *Id.* at 21.
[33] *Id.*

The parties agree that the proposal should be part of PGE's next general rate case and that the evaluation will improve the company's marginal cost estimates and provide for an improved allocation of costs to the rate schedules and delivery voltages.[34]

IV. RESOLUTION

We have reviewed the testimony presented by the parties and the comments filed with the Commission by customers and others with an interest in this proceeding.

We adopt the partial stipulation settling all of the issues not related to net variable power costs. Based on the evidence presented, we find the parties' joint proposals with respect to both revenue requirement and non-revenue requirement issues are reasonable.

We also adopt the second partial stipulation settling all of the remaining issues. Based on the evidence presented, we find the parties' joint proposals with respect to all remaining issues revenue requirement, non-revenue requirement, net variable power costs and rate spread and rate design issues to be just and reasonable.

Although we make no commitment to open an investigatory docket at this time, we may at some future date address the methodologies associated with forecasting forced outage rates for natural gas generating plants.

We conclude that our decisions in this docket will result in rates that are fair, just and reasonable.

V. ORDER

IT IS ORDERED that:

1. The partial stipulation and the second partial stipulations between the Staff of the Public Utility Commission of Oregon; Portland General Electric Company; the Citizens' Utility Board of Oregon; Fred Meyer Stores and Quality Food Centers, Divisions of Kroger Co.; and the Industrial Customers of Northwest Utilities, attached to this order as Appendices A and B, respectively, are adopted.

2. Portland General Electric Company's Revenue Requirement Estimate Update, filed October 1, 2015, attached to this order as Appendix C is adopted subject to a true-up when later data becomes available.

3. Advice No. 15-02 is permanently suspended.

[34] *Id.* at 17, 22.

4. Portland General Electric Company must file new tariffs consistent with this order by December 15, 2015, to be effective January 1, 2016.

Made, entered, and effective NOV 0 3 2015.

Susan K. Ackerman
Chair

John Savage
Commissioner

Stephen M. Bloom
Commissioner

A party may request rehearing or reconsideration of this order under ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-001-0720. A copy of the request must also be served on each party to the proceedings as provided in OAR 860-001-0180(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480 through 183.484.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 294

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.	**PARTIAL STIPULATION**

This Partial Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff'), the Citizens' Utility Board of Oregon ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), and Fred Meyer Stores and Quality Food Centers, Division of The Kroger Co. ("Kroger") (collectively, the "Stipulating Parties").

PGE filed this general rate case on February 12, 2015. The filing included fourteen separate pieces of testimony and exhibits. PGE also provided to Staff and other parties voluminous work papers in support of its filing. Since that time Staff and intervening parties have analyzed PGE's filing and work papers, and submitted several hundred data requests obtaining additional information. Settlement Conferences were held on May 21, and 29, 2015. Prior to these settlement conferences Staff provided to the other parties in this docket its settlement proposal that included numerous proposed adjustments to PGE's filed case. As a result of those discussions, the Stipulating Parties have reached a compromise settlement of several issues in this docket, as described in detail below. In addition to the Stipulating Parties, the Small Business Utility Advocates ("SBUA") attended the settlement discussions. SBUA does not oppose this Stipulation. No other parties participated in the settlement discussions.

TERMS OF PARTIAL STIPULATION

1. This Partial Stipulation resolves the issues identified below.

   a. S-1 Revenue Sensitive Costs and Uncollectibles. An uncollectible rate of 0.4032% will be used for test-year expenses.

   b. S-5 Advertising. Test-year expense will be reduced by $70,000.

   c. S-7 Medical Benefits. Non-union medical benefit expenses will be reduced by $577,000. Union medical benefit expenses will be reduced by $320,000. Company picnic expenses will be reduced by $95,000.

   d. S-9 Dues and Donations. Test-year expenses will be reduced by $194,000.

   e. S-12 Energy Efficiency. Test-year expense will be reduced by $237,000.

   f. S-13 Research and Development. Test-year expenses for research and development will be $2 million, a reduction of $1.1 million from PGE's request.

      i. PGE will, until its next general rate case, file annual reports of research and development spending.

      ii. If research and development spending is less than $2 million per year, the unspent amount will be refunded to customers.

      iii. There will be no prudence review associated with these annual filings.

   g. I-2 Construction Overheads. PGE will hire an outside expert to review its construction overheads cost allocation accounting and methodologies. The overall scope of the work will be to determine if PGE's allocation methodology readily identifies the source of the expenses and the basis for their allocation. PGE will consult with Staff and interested parties in identifying an appropriate expert and defining a scope of work. The expert will prepare a report that will be provided to Staff and interested parties.

h. The following issues were settled as a group:

S-4 Wages and Salaries

S-6 Various A&G

S-8 Pension

S-11 Escalation

S-15 Fee Free Bankcard

S-10 Capital Additions related to the North Fork Surface Collector and Grassland Switchyard

I-3 Carty Generating Station

I-7 Coal Inventory

In settlement of all of these issues:

A. For ratemaking purposes, test-year expenses will be reduced by $8 million, and rate base will be reduced by $9 million.

B. PGE agrees not to launch a commercial fee free bankcard payment program in 2016. PGE agrees to notify Staff no less than forty-five days prior to launching a commercial fee free bankcard payment program. PGE further agrees with Staff's residential bankcard program adoption rate of 9.1 percent and 13.06 percent for end of years 2015 and 2016, respectively.

C. When the North Fork Surface Collector project is placed into service PGE will file an attestation from an officer attesting that the plant has been placed into service. If the plant is not placed into service by December 31, 2015, the project costs will be removed from the test-year rate base. Project costs included in test-year rate base will be the lesser of actual project costs or $53.8 million. If North Fork capital costs are higher than that amount, PGE will not be bound to its original $53.8 million estimate in subsequent general rate proceedings. If PGE seeks to recover any additional amounts in a subsequent general rate filing, PGE must demonstrate the prudence of such additional costs.

D. The Grassland Switchyard net rate base amount of $24.686 million will be removed from year-end 2015 rate base. Grassland Switchyard plant will remain in Construction Work In Progress until the Carty Generating Station is placed into service. The parties request that the Commission approve the following accounting treatment language:

> "PGE will continue to classify the capital costs associated with the Grassland Switchyard as construction work in progress (CWIP) in FERC Account 107 until the Carty Generating Station (Carty) is placed into service. Depreciation of such amount is expected to begin when Carty is placed into service. Allowance for funds used during construction will accrue on CWIP until Carty is placed in service."

E. The parties agree that PGE's decision to construct the Carty Generating Station was prudent and the Commission should approve the Carty tariff rider requested by PGE to reflect the prudently incurred costs and benefits of the plant when it begins providing service to customers, with the following conditions:

i. For determining rates in this docket only, the gross plant for Carty, including the Grassland Switchyard, will be $514 million. If actual capital costs for Carty (including the Grassland Switchyard) are lower than the stated amount, PGE will refund the 2016 revenue requirement difference resulting from the lower capital costs, with interest at its overall authorized cost of capital, beginning January 1, 2017. If Carty capital costs are higher than the designated amount, PGE may not recover those costs through the Carty tariff rider. However, PGE will not be bound to the original $514 million estimate in subsequent rate proceedings. If PGE seeks to recover any additional amounts in a subsequent general rate filing, PGE must demonstrate the prudence of such additional costs.

ii. PGE will file an attestation by an officer when the Carty plant is placed in service.

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

2. The Stipulating Parties recommend and request that the Commission approve the adjustments and provisions described herein as appropriate and reasonable resolutions of the identified issues in this docket.

3. The Stipulating Parties agree that this Stipulation is in the public interest, and will contribute to rates that are fair, just and reasonable, consistent with the standard in ORS 756.040.

4. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all of the Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in the instant or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

5. The Stipulating Parties have negotiated this Stipulation as an integrated document. The Stipulating Parties, after consultation, may seek to obtain Commission approval of this Stipulation prior to evidentiary hearings. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right: (i) to withdraw from the Stipulation, upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation, in whole or material part, or adds such material condition; (ii) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this Stipulation; and (iii) pursuant to ORS 756.561 and OAR 860-001-0720, to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission's final order. Nothing in this paragraph provides any Stipulating Party the right to withdraw from this Stipulation as a result of the Commission's resolution of issues that this Stipulation does not resolve.

6. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Stipulation throughout this proceeding and in any appeal, and provide witnesses to support this Stipulation (if specifically required by the Commission), and recommend that the Commission issue an order adopting the settlements contained herein. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the

terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

7. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this _______ day of June, 2015.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

THE KROGER CO.

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7. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 23rd day of June, 2015.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

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DATED this _______ day of June, 2015.

____
PORTLAND GENERAL ELECTRIC
COMPANY

Johan Reinnenschneider
STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

____
CITIZENS' UTILITY BOARD
OF OREGON

____
INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

____
THE KROGER CO.

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7. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 23rd day of June, 2015.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

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7. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 22nd day of June, 2015.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

THE KROGER CO.

terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

7. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this ________ day of June, 2015.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OF OREGON

INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

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BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 294

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.	**SECOND PARTIAL STIPULATION**

This Partial Stipulation ("Stipulation") is between Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), and Fred Meyer Stores and Quality Food Centers, Division of The Kroger Co. ("Kroger") (collectively, the "Stipulating Parties"). The Small Business Utility Advocates also participated in settlement discussions and does not oppose this Stipulation. No other parties participated in the settlement discussions.

On June 23, 2015, a Partial Stipulation resolving a number of revenue requirement issues was filed in this docket. Since that time the Stipulating Parties have held numerous settlement conferences to address issues raised in the testimony filed in this docket. All power cost issues except one, and all revenue requirement issues, were settled on July 8 and 9, 2015, subject to satisfactory settlement of rate spread and rate design issues. On July 17, 2015, the parties settled all rate spread and rate design issues. As a result, when coupled with the previously filed Partial Stipulation, the parties had reached settlement of all issues in this docket except one power cost issue. That power cost issue related to the length of the maintenance outage for the Port Westward I plant as modeled in PGE's 2016 power cost forecast. A settlement conference was held on August 7, 2015, and the parties settled the one remaining power cost issue. As a result, this Second Partial Stipulation resolves all remaining issues in this docket, and the Stipulating Parties request adoption of this Second Partial Stipulation, along with the previously filed Partial Stipulation.

TERMS OF SECOND PARTIAL STIPULATION

1. This Partial Stipulation resolves the issues identified below.

   a. Load Forecast (I-5). In settlement of all load forecast issues, the Stipulating Parties agree:

      i. PGE will exclude in this rate case the price adjustment in the residential and non-residential load forecast.

      ii. PGE will work with Staff to compile a historical series of achieved energy efficiency with a goal of compiling data at the most reasonable disaggregate level, and will work with Staff to consider alternative forecasting modeling methods that incorporate energy efficiency.

      iii. PGE will work with Staff and other parties to understand PGE's load forecasting model. Staff and interested parties are also encouraged to participate in IRP workshops and meetings pertaining to or including load forecasting.

      iv. If in a subsequent docket PGE's load forecast explicitly accounts for a price effect, PGE agrees to work with the other interested parties to evaluate models that incorporate a marginal price variable into the base forecast.

b. Portfolio Options (I-8). To settle issues regarding cost allocation for renewable portfolio options, the parties agree that:

   i. PGE will audit the costs allocated to the voluntary portfolio options programs and customers, and work with Staff and interested parties, including the Portfolio Options Committee, to examine the cost allocation methodology and approach. This will be done and reviewed with Staff and the Portfolio Options Committee by November 2015. PGE will follow up on audit results with any necessary tariff filing.

   ii. Every three years after this audit, or more frequently if requested by Staff or another Stipulating Party, the allocation of costs to these portfolio options will be examined in the same manner.

c. Tariff Schedule 300 (I-10). Charges for Non-Network Residential Meter Rates will be set at: Installation of non-network meter: $100

   Non-network Meter Read: $45 per month.

   The parties further agree that PGE should make other tariff changes necessary such that customers opting for a non-network residential meter are not eligible for time-of-use rates.

d. Rate base (ICNU -1). To resolve all rate base issues raised by all parties, PGE's test-year rate base will be reduced by $18.7 million. The rate base reductions in this Stipulation and the Partial Stipulation do not incorporate the effects of Docket No. UP 310; rate base will be further reduced in the event the Commission approves the sale of poles to the City of Portland in that docket.

e. Other revenues (CUB-3). The test-year forecast of Other Revenues will be increased by $1.5 million.

f. Power costs (PC-1, PC-2, CUB-8, CUB-9, CUB-10, ICNU-7, ICNU-8, ICNU-10). In settlement of remaining power cost issues, test-year power costs will be reduced by $7.5 million. Planned maintenance for Port Westward I included in the 2016 power cost forecast will be consistent with the forecast included in PGE's April 1, 2015, MONET update. This settles all other power cost issues including California trading margins, the 2016 forced outage rate for Coyote Springs, the Super Peak Energy Purchase, load net of wind reserves, pipeline capacity release credits, the Carty modeled online date, and all other power cost issues raised in this docket. In addition to the $7.5 million reduction in power costs:

   i. PGE will propose a method for forecasting California trading margins in its next Annual Power Cost Update filing (i.e., April 1, 2016), under tariff Schedule 125.

   ii. The parties request that the Commission open a docket to address the forecasting of forced outage rates for natural gas generating plants, specifically whether there should be limits on the length of historical forced outages included in the four-year rolling average.

g. Cost of Capital (S-0, S-3, CUB-7). Revenue requirement should be set using a 9.6% return on equity, and a 50% equity, 50% debt capital structure. In settlement of cost of capital and all other issues in this docket, PGE's revenue requirement will be reduced by $4 million. Cost of debt will be updated later this year to incorporate actual 2015 debt costs, including any new issuances priced by PGE, no later than November 1, 2015. PGE will base the cost of debt update on Exhibit Staff/207C, including all updates to that document provided by Staff in July 2015 and any additional bond issuance detail for 2015. Accordingly, the revenue requirement impact of this stipulation may change.

h. PCAM (CUB-6). There will be no change in this docket to the deadbands currently contained in PGE's Annual Power Cost Variance Mechanism (PCAM) tariff, Schedule 126.

i. Marginal Cost (I-4, I-6, ICNU-2, ICNU-3). In settlement of all marginal cost issues the parties agree that in this docket:

   i. The cost of Port Westward 2 will be included as an energy cost for purposes of integrating wind energy.

   ii. The marginal cost of billing will be reduced to account for paperless billing as proposed in Staff's testimony.

   iii. Marginal capacity costs will be calculated as proposed by PGE.

   iv. Fixed pipeline costs of the marginal resource used in the marginal cost study will be included when calculating capitalized energy costs, as proposed by ICNU.

   v. All other elements of the marginal cost calculation will be consistent with the methodology presented in PGE's initial filing.

j. Ratespread and Rate Design. All ratespread and rate design issues are settled as follows:

i. Transmission revenue requirement (Staff I-1, CUB-4). Transmission revenue requirement will be allocated 25% based on energy, and 75% based on coincident peaks in the months of January, July, August, and December.

ii. Schedule Consolidation and Customer Impact Offset (Staff I-1). As part of this settlement, tariff Schedules 47 and 49 will not be priced in a manner that presumes future consolidation with Schedules 32 and 38 respectively. Schedules 38 will be priced at cost-of-service. The rate increase in this docket for Schedules 47 and 49 will be set at the greater of 13.5% or three times the overall base rate increase, excluding supplemental schedules, after inclusion of the Carty plant. Schedule 32 will bear the burden of mitigating the Schedule 47 price increase, and Schedules 83 and 85 will bear the burden of mitigating the Schedule 49 price increase.

iii. Schedule 7 Basic Charge (Staff I-1, CUB-5). The Basic Charge for Schedule 7 customers will be set at $10.50.

iv. Schedule 143 (Staff I-9). Amortization of the refund from the Trojan Nuclear Decommissioning Trust Fund under Schedule 143 will be modified as follows: Beginning January 1, 2016, Schedule 143 prices will be set to zero. Starting at the same time as the Carty plant is included in rates, Schedule 143 prices will be set to refund over the remainder of 2016 the amount that otherwise would have been amortized over 2016 if the change above had not been implemented. Beginning January 1, 2017, Schedule 143 prices will be set to amortize the remaining balance of the refund over calendar year 2017.

v. Load Following Credit (ICNU-4). The Schedule 90 load following credit will be increased in this docket from the current \$1.13/MWh to \$2.00/MWh. The portion of the credit in current rates (\$1.13/MWh for 150 average megawatts) will be allocated to all customers. The increased amount (\$0.87/MWh) will be allocated to Schedule 89 customers. In its next general rate case, PGE agrees to complete a study to evaluate the marginal cost of load following and other related ancillary services.

vi. Schedules 75 and 575 (ICNU-5). The Special Conditions in Schedules 75 and 575 will be modified as proposed by ICNU to require notice by PGE to partial requirements customers before PGE proposes a change to their baseline demand.

vii. Franchise Fees (ICNU-6). Franchise fee expenses will be allocated as originally proposed by PGE in this docket.

viii. Maintenance expenses (Kroger-1). Prior to its next rate case, PGE will evaluate the maintenance costs of secondary voltage conductors and the applicability of those costs to specific rate schedules and delivery voltages.

2. All other issues raised in this docket not otherwise specifically addressed above have been settled with no adjustments.

3. The Stipulating Parties recommend and request that the Commission approve the

adjustments and provisions described herein as appropriate and reasonable resolutions of the identified issues in this docket.

4. The Stipulating Parties agree that this Stipulation is in the public interest, and will contribute to rates that are fair, just and reasonable, consistent with the standard in ORS 756.040.

5. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the Stipulating Parties. Without the written consent of all of the Stipulating Parties, evidence of conduct or statements, including but not limited to term sheets or other documents created solely for use in settlement conferences in this docket, are confidential and not admissible in the instant or any subsequent proceeding, unless independently discoverable or offered for other purposes allowed under ORS 40.190.

6. The Stipulating Parties have negotiated this Stipulation as an integrated document. The Stipulating Parties, after consultation, may seek to obtain Commission approval of this Stipulation prior to evidentiary hearings. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order that is not consistent with this Stipulation, each Stipulating Party reserves its right: (i) to withdraw from the Stipulation, upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation, in whole or material part, or adds such material condition; (ii) pursuant to OAR 860-001-0350(9), to present evidence and argument on the record in support of the Stipulation, including the right to cross-examine witnesses, introduce evidence as deemed appropriate to respond fully to issues presented, and raise issues that are incorporated in the settlements embodied in this Stipulation; and (iii) pursuant to ORS 756.561 and OAR 860-001-0720,

to seek rehearing or reconsideration, or pursuant to ORS 756.610 to appeal the Commission's final order.

7. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR 860-001-0350(7). The Parties agree to support this Stipulation throughout this proceeding and in any appeal, and provide witnesses to support this Stipulation (if specifically required by the Commission), and recommend that the Commission issue an order adopting the settlements contained herein. By entering into this Stipulation, no Stipulating Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Stipulating Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Stipulating Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

8. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 28th day of August, 2015.

PORTLAND GENERAL ELECTRIC
COMPANY

STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

CITIZENS' UTILITY BOARD
OF OREGON

INDUSTRIAL CUSTOMERS OF
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THE KROGER CO.

Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

October 1, 2015

Email / FedEx
puc.filingcenter@state.or.us

Public Utility Commission of Oregon
201 High St SE, Suite 100
Salem, OR 97301

RE: **UE 294 Revenue Requirement Estimate Update and PGE's October MONET Update**

Filing Center:

Enclosed is a revised revenue requirement estimate for Docket No. UE 294. This revision includes PGE's October 1, 2015 MONET update, which contains contracts and electric and gas forward curves as of September 3, 2015. PGE provides this estimate as information only and does not seek any action by the Commission.

Revised Revenue Requirement Estimate
PGE's revised revenue requirement estimate shown in the table below incorporates the October 1, 2015 MONET update and the stipulations filed with the Commission in Docket No. UE 294 on June 23, 2015 and August 28, 2015. Collectively, the stipulations resolve all issues in this docket.[1]

PGE's revised revenue requirement estimate is a decrease of $15.1 million before the consideration of the Carty Generating Station (Carty), which separately represents an $84.1 million increase.

Revised Revenue Requirement ($ millions)

	Base Case	Carty	Total*
Original Filing	$38.8	$83.6	$122.4
April 1, NVPC Update	($5.2)	($1.0)	($6.2)
June 23, Stipulation	($15.3)	$2.8	($12.5)
June Load Forecast Update	$1.9	--	$1.9
July 15, NVPC Update	($2.3)	($0.7)	($3.0)
August 28, Stipulation	($28.2)	($1.4)	($29.6)
Sept. Load Forecast Update	($2.5)	--	($2.5)
Oct. 1, NVPC Update	($2.3)	$0.8	($1.5)
Total*	($15.1)	$84.1	$68.9

* May not sum due to rounding.

[1] On September 29, 2015, PGE filed its second supplemental response to OPUC Standard Data Request No. 012. In the response, PGE updated its cost of long-term debt for 2015. PGE's revised revenue requirement table in this letter does not reflect the update to PGE's cost of long-term debt.

MONET Update
Prior to PGE's adjustment to reflect an annualized amount for the Carty revenue requirement, the MONET update results in a Net Variable Power Cost (NVPC) forecast of $536.0 million. Because the Carty revenue requirement reflects annualized amounts, PGE increases Carty's dispatch benefit from $1.6 million to $2.5 million. This reduces NVPC in our case to $535.1 million for revenue requirement purposes, a decrease of roughly $11.4 million from the July 15, 2015 power cost update filing.[2] This decrease is primarily due to the reduction to PGE's NVPC forecast agreed to in the Second Partial Stipulation filed on August 28, 2015.

Summary of Attachments
As part of this update, PGE is including four attachments.

1. Attachment 1 provides PGE's revised revenue requirement as described above.
2. Confidential Attachment 2 is one (1) CD containing the confidential Minimum Filing Requirements (MFRs).
3. Attachment 3 is one (1) CD containing the non-confidential MFRs.
4. Confidential Attachment 4 is one (1) CD containing the load forecast work papers.

Attachments 2 and 4 are confidential and subject to Protective Order No. 15-036.

If you have any questions or require further information, please contact Aaron Rodehorst at 503-464-8804. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Patrick G. Hager
Manager, Regulatory Affairs

encl.

[2] See PGE's letter dated July 15, 2015 and filed in Docket No. UE 294. NVPC for revenue requirement purposes was reported to be $546.5 million.

UE 294

2016 PGE Annual Power Cost Update
October 1, 2015

Attachment 1

Provided in Electronic Format Only

Revised Revenue Requirement

Portland General Electric Company
2016 Revenue Requirement Summary
($000)

	Rev Req	Percent
Total Increase:	68,941	3.8%

	Base Business 2016	Carty	Total Results
	(1)	(2)	(3)
1 Sales to Consumers	1,784,482	84,073	1,868,555
2 Sales for Resale	-	-	-
3 Other Revenues	26,638	-	26,638
4 Total Operating Revenues	1,811,120	84,073	1,895,193
5 Net Variable Power Costs	537,594	(2,533)	535,061
6 Production O&M (excludes Trojan)	146,000	10,130	156,130
7 Trojan O&M	93	-	93
8 Transmission O&M	14,251	-	14,251
9 Distribution O&M	94,457	-	94,457
10 Customer & MBC O&M	71,776	-	71,776
11 Uncollectibles Expense	7,195	339	7,534
12 OPUC Fees	6,692	315	7,007
13 A&G, Ins/Bene., & Gen. Plant	142,717	1,644	144,361
14 Total Operating & Maintenance	1,020,776	9,896	1,030,671
15 Depreciation	270,257	14,397	284,654
16 Amortization	45,845	-	45,845
17 Property Tax	59,947	2,433	62,379
18 Payroll Tax	14,187	226	14,413
19 Other Taxes	1,798	-	1,798
20 Franchise Fees	45,452	2,141	47,594
21 Utility Income Tax	57,316	16,766	74,082
22 Total Operating Expenses & Taxes	1,515,579	45,859	1,561,437
23 **Utility Operating Income**	295,542	38,214	333,755
24 **Rate Base**			
25 Avg. Gross Plant	8,650,728	513,750	9,164,479
26 Avg. Accum. Deprec. / Amort	(4,217,975)	(7,089)	(4,225,065)
27 Avg. Accum. Def Tax	(591,593)	1,031	(590,561)
28 Avg. Accum. Def ITC	-	-	-
29 **Net Utility Plant**	3,841,160	507,693	4,348,853
30 Misc. Deferred Debits	26,623	-	26,623
31 Operating Materials & Fuel	79,458	-	79,458
32 Misc. Deferred Credits	(70,321)	(959)	(71,280)
33 Working Cash	54,987	1,664	56,651
34 **Rate Base**	3,931,907	508,398	4,440,305
35 **Rate of Return**	7.517%		7.517%
36 **Implied Return on Equity**	9.600%		9.600%

ORDER NO. 15 356

	Base Business 2016	Carty	Total Results
	(1)	(2)	(3)
37 Effective Cost of Debt	5.433%	5.433%	5.433%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.717%	2.717%	2.717%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%
44 State Tax Rate	7.212%	7.212%	7.212%
45 Federal Tax Rate	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.688%	39.688%	39.688%
47 Bad Debt Rate	0.403%	0.403%	0.403%
48 Franchise Fee Rate	2.547%	2.547%	2.547%
49 Working Cash Factor	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.658	1.658	1.658
51 ROE Target	9.600%	9.600%	9.600%
52 Grossed-Up COC	10.675%	10.675%	10.675%
53 OPUC Fee Rate	0.3750%	0.375%	0.375%
Utility Income Taxes			
54 Book Revenues	1,811,120	84,073	1,895,193
55 Book Expenses	1,458,262	29,093	1,487,355
56 Interest Deduction	106,810	13,811	120,621
57 Production Deduction	-	-	-
58 Permanent Ms	(23,836)	(1,075)	(24,911)
59 Deferred Ms	92,595	4,682	97,277
60 Taxable Income	177,289	37,562	214,851
61 Current State Tax	12,786	2,709	15,495
62 State Tax Credits	(992)	-	(992)
63 Net State Taxes	11,794	2,709	14,504
64 Federal Taxable Income	165,494	34,853	200,348
65 Current Federal Tax	57,923	12,199	70,122
66 Federal Tax Credits	(49,150)	-	(49,150)
67 ITC Amort	-	-	-
68 Deferred Taxes	36,749	1,858	38,607
69 Total Income Tax Expense	57,316	16,766	74,082
70 Regulated Net Income	188,732		213,135
71 Check Regulated NI			213,135

ORDER NO. 15 356

Portland General Electric Company
2016 Revenue Requirement - Base Business
($000)

	Rev Req	Percent
Total Increase:	(15,132)	-0.84%

	At Current Rates (1)	Sept. Load Forecast Delta (2)	GRC Change for RROE (3)	Proposed 2016 (4)	Blank (5)	Blank (6)	Blank (7)	Subtotal (8)	Non-NVPC Adjustments (5)	NVPC Adjustments (6)	Total Results (7)
1 Sales to Consumers	1,799,009	605	38,147	1,837,761	-	-	-	1,837,761	(33,234)	(20,045)	1,784,482
2 Sales for Resale	-			-				-	-	-	-
3 Other Revenues	25,138			25,138				25,138	1,500	-	26,638
4 Total Operating Revenues	1,824,147		38,147	1,862,900	-	-	-	1,862,900	(31,734)	(20,045)	1,811,120
5 Net Variable Power Costs	556,895			556,895				556,895	-	(19,301)	537,594
6 Production O&M (excludes Trojan)	146,000			146,000				146,000	-	-	146,000
7 Trojan O&M	93			93				93	-	-	93
8 Transmission O&M	14,251			14,251				14,251	-	-	14,251
9 Distribution O&M	94,457			94,457				94,457	-	-	94,457
10 Customer & MBC O&M	72,083			72,083				72,083	(307)	-	71,776
11 Uncollectibles Expense	7,736		167	7,902	-	-	-	7,902	(91)	(81)	7,195
12 OPUC Fees	6,746		145	6,892	-	-	-	6,892	(84)	(75)	6,692
13 A&G, Ins/Bene., & Gen. Plant	153,003			153,003				153,003	(10,286)	-	142,717
14 Total Operating & Maintenance	1,051,265		312	1,051,577	-	-	-	1,051,577	(10,768)	(19,457)	1,020,776
15 Depreciation	270,257			270,257				270,257	-	-	270,257
16 Amortization	49,697			49,697				49,697	(3,852)	-	45,845
17 Property Tax	59,947			59,947				59,947	-	-	59,947
18 Payroll Tax	14,187			14,187				14,167	-	-	14,187
19 Other Taxes	1,798			1,798				1,798	-	-	1,798
20 Franchise Fees	45,822		987	46,809	-	-	-	46,809	(572)	(511)	45,452
21 Utility Income Tax	48,126		14,858	62,984	-	-	-	62,984	(5,644)	(23)	57,316
22 Total Operating Expenses & Taxes	1,541,099		16,157	1,557,256	-	-	-	1,557,256	(20,836)	(19,990)	1,515,579
23 Utility Operating Income	283,049		22,595	305,644	-	-	-	305,644	(10,899)	(55)	295,542
				305,644							295,542
24 Average Rate Base											
25 Avg. Gross Plant	8,705,924			8,705,924				8,705,924	(55,196)	-	8,650,728
26 Avg. Accum. Deprec. / Amort	(4,219,464)			(4,219,464)				(4,219,464)	1,489	-	(4,217,975)
27 Avg. Accum. Def Tax	(591,970)			(591,970)				(591,970)	377	-	(591,593)
28 Avg. Accum. Def ITC	-			-				-	-	-	-
29 Avg. Net Utility Plant	3,894,490		-	3,894,490	-	-	-	3,894,490	(53,330)	-	3,841,160
30 Misc. Deferred Debits	26,623			26,623				26,623	-	-	26,623
31 Operating Materials & Fuel	79,458			79,458				79,458	-	-	79,458
32 Misc. Deferred Credits	(70,321)			(70,321)				(70,321)	-	-	(70,321)
33 Working Cash	55,913		586	56,499	-	-	-	56,499	(756)	(725)	54,987
34 Average Rate Base	3,986,163		586	3,986,749	-	-	-	3,986,749	(54,086)	(725)	3,931,907
35 Rate of Return	7.101%			7.667%							7.517%
36 Implied Return on Equity	8.769%			9.900%							9.600%

ORDER NO.

Portland General Electric Company
2016 Revenue Requirement - Carty
($000)

	As Filed (2/12/2015)	Blank	Subtotal	Settlement Uncoll. ROE	Settlement Subtotal	Capital Additions S-10	NVPC Adjustments	Total
1 Sales to Consumers	83,583	-	83,583	(1,270)	82,313	2,729	(970)	84,073
2 Sales for Resale	-	-	-		-	-	-	-
3 Other Revenues	-	-	-		-	-	-	-
4 Total Operating Revenues	83,583	-	83,583	(1,270)	82,313	2,729	(970)	84,073
5 Net Variable Power Costs	(1,599)		(1,599)	-	(1,599)	-	(934)	(2,533)
6 Production O&M (excludes Trojan)	10,130	-	10,130	-	10,130	-	-	10,130
7 Trojan O&M	-	-	-	-	-	-	-	-
8 Transmission O&M	-	-	-	-	-	-	-	-
9 Distribution O&M	-	-	-	-	-	-	-	-
10 Customer & MBC O&M	-	-	-	-	-	-	-	-
11 Uncollectibles Expense	359	-	359	(5)	332	11	(4)	339
12 OPUC Fees	313	-	313	(5)	309	10	(4)	315
13 A&G, Ins/Bene., & Gen. Plant	1,644	-	1,644	-	1,644	-	-	1,644
14 Total Operating & Maintanance	10,849	-	10,849	(10)	10,816	21	(942)	9,896
15 Depreciation	14,397		14,397	-	14,397	-	-	14,397
16 Amortization	-		-	-	-	-	-	-
17 Property Tax	2,433		2,433	-	2,433	-	-	2,433
18 Payroll Tax	226	-	226	-	226	-	-	226
19 Other Taxes	-	-	-	-	-	-	-	-
20 Franchise Fees	2,129	-	2,129	(32)	2,097	70	(25)	2,141
21 Utility Income Tax	16,464	-	16,464	(487)	15,986	781	(1)	16,766
22 Total Operating Expenses & Taxes	46,498	-	46,498	(529)	45,955	871	(967)	45,859
23 **Utility Operating Income**	37,086	-	37,086	(741)	36,358	1,858	(3)	38,214
24 **Average Rate Base**								
25 Avg. Gross Plant	488,250		488,250	-	488,250	25,500	-	513,750
26 Avg. Accum. Deprec. / Amort	(6,598)		(6,598)	-	(6,598)	(491)	-	(7,089)
27 Avg. Accum. Def Tax	1,354		1,354	-	1,354	(323)	-	1,031
29 **Avg. Net Utility Plant**	483,007	-	483,007	-	483,007	24,686	-	507,693
30 Misc. Deferred Debits	-	-	-	-	-	-	-	-
31 Operating Materials & Fuel	-	-	-	-	-	-	-	-
32 Misc. Deferred Credits	(959)	-	(959)	-	(959)	-	-	(959)
33 Working Cash	1,687	-	1,687	(19)	1,667	32	(35)	1,664
34 **Average Rate Base**	483,735	-	483,735	(19)	483,715	24,718	(35)	508,398
35 **Rate of Return**	7.667%		7.667%					7.517%
36 **Implied Return on Equity**	9.900%		9.900%					9.600%

37 Effective Cost of Debt	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%
38 Effective Cost of Preferred	0.000%	0.000%	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%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%
42 Weighted Cost of Preferred	0.000%	0.000%	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%	50.000%	50.000%
44 State Tax Rate	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%
47 Bad Debt Rate	0.430%	0.430%	0.430%	0.4032%	0.403%	0.403%	0.403%	0.403%
48 Franchise Fee Rate	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%
49 Working Cash Factor	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658
51 ROE Target	9.900%	9.900%	9.900%	9.600%	9.600%	9.600%	9.600%	9.600%
52 Grossed-Up COC	10.924%	10.924%	10.924%	10.675%	10.675%	10.675%	10.675%	10.675%
53 OPUC Fee Rate	0.375%	0.375%	0.375%	0.375%	0.375%	0.375%	0.375%	0.375%
Utility Income Taxes								
54 Book Revenues	83,583	-	83,583	(1,270)	82,313	2,729	(970)	84,073
55 Book Expenses	30,033	-	30,033	(42)	29,969	91	(966)	29,093
56 Interest Deduction	13,141	-	13,141	(1)	13,140	671	(1)	13,811
57 Production Deduction	-	-	-	-	-	-	-	-
58 Permanent Ms	(1,075)		(1,075)	-	(1,075)	-	-	(1,075)
59 Deferred Ms	4,682		4,682	-	4,682	-	-	4,682
60 Taxable Income	36,803	-	36,803	(1,227)	35,598	1,967	(3)	37,562
61 Current State Tax	2,654	-	2,654	(88)	2,567	142	(0)	2,709
62 State Tax Credits	-	-	-	-	-	-	-	-
63 Net State Taxes	2,654	-	2,654	(88)	2,567	142	(0)	2,709
64 Federal Taxable Income	34,148	-	34,148	(1,139)	33,031	1,825	(3)	34,853
65 Current Federal Tax	11,952	-	11,952	(398)	11,561	639	(1)	12,199
66 Federal Tax Credits	-	-	-	-	-	-	-	-
67 ITC Amort	-	-	-	-	-	-	-	-
68 Deferred Taxes	1,858	-	1,858	-	1,858	-	-	1,858
69 Total Income Tax Expense	16,464	-	16,464	(487)	15,986	781	(1)	16,766
70 Regulated Net Income								
71 Check Regulated NI								

Non-NVPC Adjustment Detail

	All Revenue Sensitive	7/9/2015 ROE	Cost of Debt	Uncollectibles	Rev Sensitive S-1, S-2, S-3	Advertising S-5	Medical Benefits S-7	6/23/2015 Dues & Donations S-9	Cap. Adds Rate Base S-10	Energy Efficiency S-12	R&D S-13
	(10,785)	(10,276)	-	(512)							
1 Sales to Consumers	1,826,976	1,827,485	1,837,761	1,837,250	(10,785)	(73)	(1,030)	(201)	(2,729)	(246)	(1,142)
2 Sales for Resale	-	-	-	-							
3 Other Revenues	25,138	25,138	25,138	25,138							
4 Total Operating Revenues	1,852,115	1,852,623	1,862,900	1,862,388	(10,785)	(73)	(1,030)	(201)	(2,729)	(246)	(1,142)
5 Net Variable Power Costs	556,895	556,895	556,895	556,895							
6 Production O&M (Excludes Trojan)	146,000	146,000	146,000	146,000							
7 Trojan O&M	93	93	93	93							
8 Transmission O&M	14,251	14,251	14,251	14,251							
9 Distribution O&M	94,457	94,457	94,457	94,457							
10 Customer & MBC O&M	72,083	72,083	72,083	72,083		(70)				(237)	
11 Uncollectibles Expense	7,366	7,858	7,902	7,408	(536)	(0)	(4)	(1)	(11)	(1)	(5)
12 OPUC Fees	6,851	6,853	6,892	6,890	(40)	(0)	(4)	(1)	(10)	(1)	(4)
13 A&G, Ins/Bene., & Gen. Plant	153,003	153,003	153,003	153,003			(992)	(194)			(1,100)
14 Total Operating & Maintenance	1,051,000	1,051,494	1,051,577	1,051,080	(576)	(71)	(1,000)	(196)	(21)	(239)	(1,109)
15 Depreciation	270,257	270,257	270,257	270,257							
16 Amortization	49,697	49,697	49,697	49,697							
17 Property Tax	59,947	59,947	59,947	59,947							
18 Payroll Tax	14,187	14,187	14,187	14,187							
19 Other Taxes	1,798	1,798	1,798	1,798							
20 Franchise Fees	46,535	46,548	46,809	46,796	(275)	(2)	(26)	(5)	(70)	(6)	(29)
21 Utility Income Tax	59,043	59,044	62,984	62,983	(3,941)	(0)	(1)	(0)	(781)	(0)	(1)
22 Total Operating Expenses & Taxes	1,552,464	1,552,971	1,557,256	1,556,746	(4,792)	(73)	(1,027)	(201)	(871)	(245)	(1,139)
23 **Utility Operating Income**	299,651	299,652	305,644	305,643	(5,993)	(0)	(3)	(1)	(1,858)	(1)	(3)
	299,651	299,652	305,644	305,643							
24 **Average Rate Base**											
25 Avg. Gross Plant	8,705,924	8,705,924	8,705,924	8,705,924					(25,500)		
26 Avg. Accum. Deprec. / Amort	(4,219,464)	(4,219,464)	(4,219,464)	(4,219,464)					491		
27 Avg. Accum. Def Tax	(591,970)	(591,970)	(591,970)	(591,970)					323		
28 Avg. Accum. Def ITC	-	-	-	-							
29 **Avg. Net Utility Plant**	3,894,490	3,894,490	3,894,490	3,894,490	-	-	-	-	(24,686)	-	-
30 Misc. Deferred Debits	26,623	26,623	26,623	26,623							
31 Operating Materials & Fuel	79,458	79,458	79,458	79,458							
32 Misc. Deferred Credits	(70,321)	(70,321)	(70,321)	(70,321)							
33 Working Cash	56,325	56,343	56,499	56,480	(174)	(3)	(37)	(7)	(32)	(9)	(41)
34 **Average Rate Base**	3,986,575	3,986,593	3,986,749	3,986,730	(174)	(3)	(37)	(7)	(24,718)	(9)	(41)
35 **Rate of Return**	7.517%	7.517%	7.667%	7.667%							
36 **Implied Return on Equity**	9.600%	9.600%	9.900%	9.900%							

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37 Effective Cost of Debt	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	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%	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%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	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%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%
47 Bad Debt Rate	0.4032%	0.4300%	0.4300%	0.4032%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%
48 Franchise Fee Rate	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%
49 Working Cash Factor	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658
51 ROE Target	9.600%	9.600%	9.900%	9.900%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%
52 Grossed-Up COC	10.675%	10.675%	10.924%	10.924%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%
53 OPUC Fee Rate	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%
Utility Income Taxes											
54 Book Revenues	1,852,115	1,852,623	1,862,900	1,862,388	(10,785)	(73)	(1,030)	(201)	(2,729)	(246)	(1,142)
55 Book Expenses	1,493,421	1,493,928	1,494,272	1,493,763	(851)	(72)	(1,026)	(201)	(91)	(245)	(1,138)
56 Interest Deduction	108,295	108,296	108,300	108,300	(5)	(0)	(1)	(0)	(671)	(0)	(1)
57 Production Deduction	-	-	-	-							
58 Permanent Ms	(23,836)	(23,836)	(23,836)	(23,836)							
59 Deferred Ms	92,595	92,595	92,595	92,595							
60 Taxable Income	181,640	181,641	191,569	191,567	(9,929)	(0)	(3)	(1)	(1,967)	(1)	(3)
61 Current State Tax	13,100	13,100	13,816	13,816	(716)	(0)	(0)	(0)	(142)	(0)	(0)
62 State Tax Credits	(992)	(992)	(992)	(992)							
63 Net State Taxes	12,108	12,108	12,824	12,824	(716)	(0)	(0)	(0)	(142)	(0)	(0)
64 Federal Taxable Income	169,531	169,533	178,744	178,743	(9,213)	(0)	(3)	(1)	(1,825)	(1)	(3)
65 Current Federal Tax	59,336	59,336	62,561	62,560	(3,225)	(0)	(1)	(0)	(639)	(0)	(1)
66 Federal Tax Credits	(49,150)	(49,150)	(49,150)	(49,150)							
67 ITC Amort	-	-	-	-							
68 Deferred Taxes	36,749	36,749	36,749	36,749	-	-	-	-	-	-	-
69 Total Income Tax Expense	59,043	59,044	62,984	62,983	(3,941)	(0)	(1)	(0)	(781)	(0)	(1)
73 Regulated Net Income	191,356	191,356	197,344	197,343	(5,988)	(0)	(2)	(0)	(1,186)		

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Non-NVPC Adjustment Detail

	7/9/2015 Settlement				UP 310					
	Partial Settlement	ICNU Rate Base	CUB Other Rev	All Parties Return	CoP Pole and Circuit Sale	Blank	Blank	Blank	Blank	**Total Non-NVPC Adjustments**
1 Sales to Consumers	(9,303)	(2,068)	(1,552)	(4,000)	(104)	-	-	-	-	(33,234)
2 Sales for Resale										-
3 Other Revenues			1,500							1,500
4 Total Operating Revenues	(9,303)	(2,068)	(52)	(4,000)	(104)	-	-	-	-	(31,734)
5 Net Variable Power Costs										-
6 Production O&M (Excludes Trojan)										-
7 Trojan O&M										-
8 Transmission O&M										-
9 Distribution O&M										-
10 Customer & MBC O&M										(307)
11 Uncollectibles Expense	(38)	(8)	(6)	(16)	(0)	-	-	-	-	(91)
12 OPUC Fees	(35)	(8)	(6)	(15)	(0)	-	-	-	-	(84)
13 A&G, Ins/Bene., & Gen. Plant	(8,000)			-						(10,286)
14 Total Operating & Maintenance	(8,072)	(16)	(12)	(31)	(1)	-	-	-	-	(10,768)
15 Depreciation				-						-
16 Amortization				(3,852)						(3,852)
17 Property Tax										-
18 Payroll Tax										-
19 Other Taxes				-						-
20 Franchise Fees	(237)	(53)	(40)	(102)	(3)	-	-	-	-	(572)
21 Utility Income Tax	(294)	(591)	(0)	(5)	(30)	-	-	-	-	(1,704)
22 Total Operating Expenses & Taxes	(8,603)	(660)	(52)	(3,989)	(33)	-	-	-	-	(16,895)
23 **Utility Operating Income**	(700)	(1,407)	(0)	(11)	(71)	-	-	-	-	(14,840)
24 **Average Rate Base**										
25 Avg. Gross Plant	(9,000)	(18,700)			(1,996)					(55,196)
26 Avg. Accum. Deprec. / Amort					998					1,489
27 Avg. Accum. Def Tax					54					377
28 Avg. Accum. Def ITC										-
29 **Avg. Net Utility Plant**	(9,000)	(18,700)	-	-	(944)	-	-	-	-	(53,330)
30 Misc. Deferred Debits										-
31 Operating Materials & Fuel										-
32 Misc. Deferred Credits										-
33 Working Cash	(312)	(24)	(2)	(145)	(1)	-	-	-	-	(613)
34 **Average Rate Base**	(9,312)	(18,724)	(2)	(145)	(945)	-	-	-	-	(53,943)
35 **Rate of Return**										
36 **Implied Return on Equity**										

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37 Effective Cost of Debt	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	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%	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%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	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%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%
47 Bad Debt Rate	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%
48 Franchise Fee Rate	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%
49 Working Cash Factor	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658
51 ROE Target	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%
52 Grossed-Up COC	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%
53 OPUC Fee Rate	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%
Utility Income Taxes										
54 Book Revenues	(9,303)	(2,068)	(52)	(4,000)	(104)	-	-	-	-	(31,734)
55 Book Expenses	(8,309)	(69)	(52)	(3,985)	(3)	-	-	-	-	(15,191)
56 Interest Deduction	(253)	(509)	(0)	(4)	(26)	-	-	-	-	(1,465)
57 Production Deduction										-
58 Permanent Ms										-
59 Deferred Ms										-
60 Taxable Income	(741)	(1,490)	(0)	(12)	(75)	-	-	-	-	(15,078)
61 Current State Tax	(53)	(107)	(0)	(1)	(5)	-	-	-	-	(1,087)
62 State Tax Credits										-
63 Net State Taxes	(53)	(107)	(0)	(1)	(5)	-	-	-	-	(1,087)
64 Federal Taxable Income	(688)	(1,383)	(0)	(11)	(70)	-	-	-	-	(13,991)
65 Current Federal Tax	(241)	(484)	(0)	(4)	(24)	-	-	-	-	(4,897)
66 Federal Tax Credits										-
67 ITC Amort										-
68 Deferred Taxes	-	-	-	-	-	-	-	-	-	-
69 Total Income Tax Expense	(294)	(591)	(0)	(5)	(30)	-	-	-	-	(5,984)
73 Regulated Net Income	(447)	(899)	(0)	(7)				-		(13,374)

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APPENDIX C
Page 12 of 30

NVPC Adjustment Detail

	4/1/2015 NVPC Update (1)	7/15/2015 NVPC Update (2)	8/12/2015 Settlement Update	10/1/2015 NVPC Update (3)	11/5/2015 NVPC Update (3)	11/16/2015 NVPC Update (3)	**Total NVPC Adjustments**
1 Sales to Consumers	(5,155)	(2,318)	(10,234)	(2,338)	-	-	(20,045)
2 Sales for Resale							-
3 Other Revenues							-
4 Total Operating Revenues	(5,155)	(2,318)	(10,234)	(2,338)	-	-	(20,045)
5 Net Variable Power Costs	(4,964)	(2,232)	(9,854)	(2,251)	-	-	(19,301)
6 Production O&M (Excludes Trojan)							-
7 Trojan O&M							-
8 Transmission O&M							-
9 Distribution O&M							-
10 Customer & MBC O&M							-
11 Uncollectibles Expense	(21)	(9)	(41)	(9)	-	-	(81)
12 OPUC Fees	(19)	(9)	(38)	(9)	-	-	(75)
13 A&G, Ins/Bene., & Gen. Plant							-
14 Total Operating & Maintenance	(5,004)	(2,250)	(9,934)	(2,269)	-	-	(19,457)
15 Depreciation							-
16 Amortization							-
17 Property Tax							-
18 Payroll Tax							-
19 Other Taxes							-
20 Franchise Fees	(131)	(59)	(261)	(60)	-	-	(511)
21 Utility Income Tax	(6)	(3)	(12)	(3)	-	-	(23)
22 Total Operating Expenses & Taxes	(5,141)	(2,312)	(10,206)	(2,331)	-	-	(19,990)
23 **Utility Operating Income**	(14)	(6)	(28)	(6)	-	-	(55)
24 **Average Rate Base**							
25 Avg. Gross Plant							-
26 Avg. Accum. Deprec. / Amort							-
27 Avg. Accum. Def Tax							-
28 Avg. Accum. Def ITC							-
29 **Avg. Net Utility Plant**	-	-	-	-	-	-	-
30 Misc. Deferred Debits							-
31 Operating Materials & Fuel							-
32 Misc. Deferred Credits							-
33 Working Cash	(187)	(84)	(370)	(85)	-	-	(725)
34 **Average Rate Base**	(187)	(84)	(370)	(85)	-	-	(725)
35 **Rate of Return**	7.516%						7.516%
36 **Implied Return on Equity**	9.600%						9.600%

37 Effective Cost of Debt	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%
38 Effective Cost of Preferred	0.000%	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%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%
42 Weighted Cost of Preferred	0.000%	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%	50.000%
44 State Tax Rate	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%
47 Bad Debt Rate	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%
48 Franchise Fee Rate	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%
49 Working Cash Factor	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.658	1.658	1.658	1.658	1.658	1.658	1.658
51 ROE Target	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%
52 Grossed-Up COC	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%
53 OPUC Fee Rate	0.375%	0.375%	0.375%	0.375%	0.375%	0.375%	0.375%
Utility Income Taxes							
54 Book Revenues	(5,155)	(2,318)	(10,234)	(2,338)	-	-	(20,045)
55 Book Expenses	(5,135)	(2,309)	(10,194)	(2,329)	-	-	(19,968)
56 Interest Deduction	(5)	(2)	(10)	(2)	-	-	(20)
57 Production Deduction							-
58 Permanent Ms							-
59 Deferred Ms							-
60 Taxable Income	(15)	(7)	(29)	(7)	-	-	(58)
61 Current State Tax	(1)	(0)	(2)	(0)	-	-	(4)
62 State Tax Credits							-
63 Net State Taxes	(1)	(0)	(2)	(0)	-	-	(4)
64 Federal Taxable Income	(14)	(6)	(27)	(6)	-	-	(54)
65 Current Federal Tax	(5)	(2)	(10)	(2)	-	-	(19)
66 Federal Tax Credits							-
67 ITC Amort							-
68 Deferred Taxes	-	-	-	-	-	-	-
69 Total Income Tax Expense	(6)	(3)	(12)	(3)	-	-	(23)
73 Regulated Net Income	(9)	(4)	(18)	(4)	-	-	(35)

Category A Advertising
Adjust Result to 1/8 of 1% per OAR

9090001 CustSvc-InformAdvertisingExp	2,113,423
Less: Legally Mandated Advertising	25,750
	2,087,673
2016 Total Revenue Requirement	1,868,555
Factor per OAR	0.125%
Presumed Reasonable Cat A Costs	2,335,693
Total Adjustment	-

UE 294

2016 PGE Annual Power Cost Update
October 1, 2015

Attachment 2

Provided in Electronic Format (CD) Only

Confidential and Subject to Protective Order No. 15-036

Minimum Filing Requirements
Supporting Documents and Work Papers

UE 294

2016 PGE Annual Power Cost Update
October 1, 2015

Attachment 3

Provided in Electronic Format (CD) Only

Minimum Filing Requirements
Non-Confidential Supporting Documents and Work Papers

UE 294

2016 PGE Annual Power Cost Update
October 1, 2015

Attachment 4

Provided in Electronic Format (CD) Only

Confidential and Subject to Protective Order No. 15-036

PGE Energy and Load Forecast Work Papers
SSEP15E

Portland General Electric Company
2016 Revenue Requirement Summary
($000)

	Rev Req	Percent
Total Increase:	68,941	3.8%

	Base Business 2016 (1)	Carty (2)	Total Results (3)
1 Sales to Consumers	1,784,482	84,073	1,868,555
2 Sales for Resale	-	-	-
3 Other Revenues	26,638	-	26,638
4 Total Operating Revenues	1,811,120	84,073	1,895,193
5 Net Variable Power Costs	537,594	(2,533)	535,061
6 Production O&M (excludes Trojan)	146,000	10,130	156,130
7 Trojan O&M	93	-	93
8 Transmission O&M	14,251	-	14,251
9 Distribution O&M	94,457	-	94,457
10 Customer & MBC O&M	71,776	-	71,776
11 Uncollectibles Expense	7,195	339	7,534
12 OPUC Fees	6,692	315	7,007
13 A&G, Ins/Bene., & Gen. Plant	142,717	1,644	144,361
14 Total Operating & Maintenance	1,020,776	9,896	1,030,671
15 Depreciation	270,257	14,397	284,654
16 Amortization	45,845	-	45,845
17 Property Tax	59,947	2,433	62,379
18 Payroll Tax	14,187	226	14,413
19 Other Taxes	1,798	-	1,798
20 Franchise Fees	45,452	2,141	47,594
21 Utility Income Tax	57,316	16,766	74,082
22 Total Operating Expenses & Taxes	1,515,579	45,859	1,561,437
23 **Utility Operating Income**	295,542	38,214	333,755
24 **Rate Base**			
25 Avg. Gross Plant	8,650,728	513,750	9,164,479
26 Avg. Accum. Deprec. / Amort	(4,217,975)	(7,089)	(4,225,065)
27 Avg. Accum. Def Tax	(591,593)	1,031	(590,561)
28 Avg. Accum. Def ITC	-	-	-
29 **Net Utility Plant**	3,841,160	507,693	4,348,853
30 Misc. Deferred Debits	26,623	-	26,623
31 Operating Materials & Fuel	79,458	-	79,458
32 Misc. Deferred Credits	(70,321)	(959)	(71,280)
33 Working Cash	54,987	1,664	56,651
34 **Rate Base**	3,931,907	508,398	4,440,305
35 **Rate of Return**	7.517%		7.517%
36 **Implied Return on Equity**	9.600%		9.600%

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	Base Business 2016	Carty	Total Results
	(1)	(2)	(3)
37 Effective Cost of Debt	5.433%	5.433%	5.433%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%
39 Debt Share of Cap Structure	50.000%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.717%	2.717%	2.717%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%
43 Equity Share of Cap Structure	50.000%	50.000%	50.000%
44 State Tax Rate	7.212%	7.212%	7.212%
45 Federal Tax Rate	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.688%	39.688%	39.688%
47 Bad Debt Rate	0.403%	0.403%	0.403%
48 Franchise Fee Rate	2.547%	2.547%	2.547%
49 Working Cash Factor	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.658	1.658	1.658
51 ROE Target	9.600%	9.600%	9.600%
52 Grossed-Up COC	10.675%	10.675%	10.675%
53 OPUC Fee Rate	0.3750%	0.375%	0.375%
Utility Income Taxes			
54 Book Revenues	1,811,120	84,073	1,895,193
55 Book Expenses	1,458,262	29,093	1,487,355
56 Interest Deduction	106,810	13,811	120,621
57 Production Deduction	-	-	-
58 Permanent Ms	(23,836)	(1,075)	(24,911)
59 Deferred Ms	92,595	4,682	97,277
60 Taxable Income	177,289	37,562	214,851
61 Current State Tax	12,786	2,709	15,495
62 State Tax Credits	(992)	-	(992)
63 Net State Taxes	11,794	2,709	14,504
64 Federal Taxable Income	165,494	34,853	200,348
65 Current Federal Tax	57,923	12,199	70,122
66 Federal Tax Credits	(49,150)	-	(49,150)
67 ITC Amort	-	-	-
68 Deferred Taxes	36,749	1,858	38,607
69 Total Income Tax Expense	57,316	16,766	74,082
70 Regulated Net Income	188,732		213,135
71 Check Regulated NI			213,135

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Portland General Electric Company
2016 Revenue Requirement - Base Business
($000)

	Rev Req	Percent
Total Increase:	(15,132)	-0.84%

	At Current Rates (1)	Sept. Load Forecast Delta (2)	GRC Change for RROE (3)	Proposed 2016 (4)	Blank (5)	Blank (6)	Blank (7)	Subtotal (8)	Non-NVPC Adjustments (5)	NVPC Adjustments (6)	Total Results (7)
1 Sales to Consumers	1,799,009	605	38,147	1,837,761	-	-	-	1,837,761	(33,234)	(20,045)	1,784,462
2 Sales for Resale	-			-				-	-	-	-
3 Other Revenues	25,138			25,138				25,138	1,500	-	26,638
4 Total Operating Revenues	1,824,147		38,147	1,862,900	-	-	-	1,862,900	(31,734)	(20,045)	1,811,120
5 Net Variable Power Costs	556,895			556,895				556,895	-	(19,301)	537,594
6 Production O&M (excludes Trojan)	146,000			146,000				146,000	-	-	146,000
7 Trojan O&M	93			93				93	-	-	93
8 Transmission O&M	14,251			14,251				14,251	-	-	14,251
9 Distribution O&M	94,457			94,457				94,457	-	-	94,457
10 Customer & MBC O&M	72,083			72,083				72,083	(307)	-	71,776
11 Uncollectibles Expense	7,736		167	7,902	-	-	-	7,902	(91)	(81)	7,195
12 OPUC Fees	6,746		145	6,892	-	-	-	6,892	(84)	(75)	6,692
13 A&G, Ins/Bene., & Gen. Plant	153,003			153,003				153,003	(10,286)	-	142,717
14 Total Operating & Maintenance	1,051,265		312	1,051,577	-	-	-	1,051,577	(10,768)	(19,457)	1,020,776
15 Depreciation	270,257			270,257				270,257	-	-	270,257
16 Amortization	49,697			49,697				49,697	(3,852)	-	45,845
17 Property Tax	59,947			59,947				59,947	-	-	59,947
18 Payroll Tax	14,187			14,187				14,187	-	-	14,187
19 Other Taxes	1,798			1,798				1,798	-	-	1,798
20 Franchise Fees	45,822		987	46,809	-	-	-	46,809	(572)	(511)	45,452
21 Utility Income Tax	48,126		14,858	62,984	-	-	-	62,984	(5,644)	(23)	57,316
22 Total Operating Expenses & Taxes	1,541,099		16,157	1,557,256	-	-	-	1,557,256	(20,836)	(19,990)	1,515,579
23 **Utility Operating Income**	283,049		22,595	305,644	-	-	-	305,644	(10,899)	(55)	295,542
				305,644							295,542
24 **Average Rate Base**											
25 Avg. Gross Plant	8,705,924			8,705,924				8,705,924	(55,196)	-	8,650,728
26 Avg. Accum. Deprec. / Amort	(4,219,464)			(4,219,464)				(4,219,464)	1,489	-	(4,217,975)
27 Avg. Accum. Def Tax	(591,970)			(591,970)				(591,970)	377	-	(591,593)
28 Avg. Accum. Def ITC	-			-				-	-	-	-
29 **Avg. Net Utility Plant**	3,894,490		-	3,894,490	-	-	-	3,894,490	(53,330)	-	3,841,160
30 Misc. Deferred Debits	26,623			26,623				26,623	-	-	26,623
31 Operating Materials & Fuel	79,458			79,458				79,458	-	-	79,458
32 Misc. Deferred Credits	(70,321)			(70,321)				(70,321)	-	-	(70,321)
33 Working Cash	55,913		586	56,499	-	-	-	56,499	(756)	(725)	54,987
34 **Average Rate Base**	3,986,163		586	3,986,749	-	-	-	3,986,749	(54,086)	(725)	3,931,907
35 **Rate of Return**	7.101%			7.667%							7.517%
36 **Implied Return on Equity**	8.769%			9.900%							9.600%

ORDER NO. 15 356

Portland General Electric Company
2016 Revenue Requirement - Carty
($000)

	As Filed (2/12/2015)	Blank	Subtotal	Settlement Uncoll. ROE	Settlement Subtotal	Capital Additions S-10	NVPC Adjustments	Total
1 Sales to Consumers	83,583	-	83,583	(1,270)	82,313	2,729	(970)	84,073
2 Sales for Resale	-	-	-		-	-	-	-
3 Other Revenues	-	-	-		-	-	-	-
4 Total Operating Revenues	83,583	-	83,583	(1,270)	82,313	2,729	(970)	84,073
5 Net Variable Power Costs	(1,599)		(1,599)	-	(1,599)	-	(934)	(2,533)
6 Production O&M (excludes Trojan)	10,130	-	10,130	-	10,130	-	-	10,130
7 Trojan O&M	-	-	-	-	-	-	-	-
8 Transmission O&M	-	-	-	-	-	-	-	-
9 Distribution O&M	-	-	-	-	-	-	-	-
10 Customer & MBC O&M	-	-	-	-	-	-	-	-
11 Uncollectibles Expense	359	-	359	(5)	332	11	(4)	339
12 OPUC Fees	313	-	313	(5)	309	10	(4)	315
13 A&G, Ins/Bene., & Gen. Plant	1,644	-	1,644	-	1,644	-	-	1,644
14 Total Operating & Maintenance	10,849	-	10,849	(10)	10,816	21	(942)	9,896
15 Depreciation	14,397		14,397	-	14,397	-	-	14,397
16 Amortization	-		-	-	-	-	-	-
17 Property Tax	2,433		2,433	-	2,433	-	-	2,433
18 Payroll Tax	226	-	226	-	226	-	-	226
19 Other Taxes	-	-	-	-	-	-	-	-
20 Franchise Fees	2,129	-	2,129	(32)	2,097	70	(25)	2,141
21 Utility Income Tax	16,464	-	16,464	(487)	15,986	781	(1)	16,766
22 Total Operating Expenses & Taxes	46,498	-	46,498	(529)	45,955	871	(967)	45,859
23 Utility Operating Income	37,086	-	37,086	(741)	36,358	1,858	(3)	38,214
24 Average Rate Base								
25 Avg. Gross Plant	488,250		488,250	-	488,250	25,500	-	513,750
26 Avg. Accum. Deprec. / Amort	(6,598)		(6,598)	-	(6,598)	(491)	-	(7,089)
27 Avg. Accum. Def Tax	1,354		1,354	-	1,354	(323)	-	1,031
29 Avg. Net Utility Plant	483,007	-	483,007	-	483,007	24,686	-	507,693
30 Misc. Deferred Debits	-	-	-	-	-	-	-	-
31 Operating Materials & Fuel	-	-	-	-	-	-	-	-
32 Misc. Deferred Credits	(959)	-	(959)	-	(959)	-	-	(959)
33 Working Cash	1,687	-	1,687	(19)	1,667	32	(35)	1,664
34 Average Rate Base	483,735	-	483,735	(19)	483,715	24,718	(35)	508,398
35 Rate of Return	7.667%		7.667%					7.517%
36 Implied Return on Equity	9.900%		9.900%					9.600%

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37 Effective Cost of Debt	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%
38 Effective Cost of Preferred	0.000%	0.000%	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%	50.000%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%
42 Weighted Cost of Preferred	0.000%	0.000%	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%	50.000%	50.000%
44 State Tax Rate	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%
47 Bad Debt Rate	0.430%	0.430%	0.430%	0.4032%	0.403%	0.403%	0.403%	0.403%
48 Franchise Fee Rate	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%
49 Working Cash Factor	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658
51 ROE Target	9.900%	9.900%	9.900%	9.600%	9.600%	9.600%	9.600%	9.600%
52 Grossed-Up COC	10.924%	10.924%	10.924%	10.675%	10.675%	10.675%	10.675%	10.675%
53 OPUC Fee Rate	0.375%	0.375%	0.375%	0.375%	0.375%	0.375%	0.375%	0.375%
Utility Income Taxes								
54 Book Revenues	83,583	-	83,583	(1,270)	82,313	2,729	(970)	84,073
55 Book Expenses	30,033	-	30,033	(42)	29,969	91	(966)	29,093
56 Interest Deduction	13,141	-	13,141	(1)	13,140	671	(1)	13,811
57 Production Deduction	-	-	-	-	-	-	-	-
58 Permanent Ms	(1,075)		(1,075)	-	(1,075)	-	-	(1,075)
59 Deferred Ms	4,682		4,682	-	4,682	-	-	4,682
60 Taxable Income	36,803	-	36,803	(1,227)	35,598	1,967	(3)	37,562
61 Current State Tax	2,654	-	2,654	(88)	2,567	142	(0)	2,709
62 State Tax Credits	-	-	-	-	-	-	-	-
63 Net State Taxes	2,654	-	2,654	(88)	2,567	142	(0)	2,709
64 Federal Taxable Income	34,148	-	34,148	(1,139)	33,031	1,825	(3)	34,853
65 Current Federal Tax	11,952	-	11,952	(398)	11,561	639	(1)	12,199
66 Federal Tax Credits	-	-	-	-	-	-	-	-
67 ITC Amort	-	-	-	-	-	-	-	-
68 Deferred Taxes	1,858	-	1,858	-	1,858	-	-	1,858
69 Total Income Tax Expense	16,464	-	16,464	(487)	15,986	781	(1)	16,766
70 Regulated Net Income								
71 Check Regulated NI								

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Non-NVPC Adjustment Detail

	All Revenue Sensitive	ROE	Cost of Debt	Uncollectibles	Rev Sensitive	Advertising	Medical Benefits	Dues & Donations	Cap. Adds Rate Base	Energy Efficiency	R&D
		7/9/2015		6/23/2015							
					S-1, S-2, S-3	S-5	S-7	S-9	S-10	S-12	S-13
	(10,785)	(10,276)	-	(512)							
1 Sales to Consumers	1,826,976	1,827,485	1,837,761	1,837,250	(10,785)	(73)	(1,030)	(201)	(2,729)	(246)	(1,142)
2 Sales for Resale	-	-	-	-							
3 Other Revenues	25,138	25,138	25,138	25,138							
4 Total Operating Revenues	1,852,115	1,852,623	1,862,900	1,862,388	(10,785)	(73)	(1,030)	(201)	(2,729)	(246)	(1,142)
5 Net Variable Power Costs	556,895	556,895	556,895	556,895							
6 Production O&M (Excludes Trojan)	146,000	146,000	146,000	146,000							
7 Trojan O&M	93	93	93	93							
8 Transmission O&M	14,251	14,251	14,251	14,251							
9 Distribution O&M	94,457	94,457	94,457	94,457							
10 Customer & MBC O&M	72,083	72,083	72,083	72,083		(70)				(237)	
11 Uncollectibles Expense	7,366	7,858	7,902	7,408	(536)	(0)	(4)	(1)	(11)	(1)	(5)
12 OPUC Fees	6,851	6,853	6,892	6,890	(40)	(0)	(4)	(1)	(10)	(1)	(4)
13 A&G, Ins/Bene., & Gen. Plant	153,003	153,003	153,003	153,003			(992)	(194)			(1,100)
14 Total Operating & Maintenance	1,051,000	1,051,494	1,051,577	1,051,080	(576)	(71)	(1,000)	(196)	(21)	(239)	(1,109)
15 Depreciation	270,257	270,257	270,257	270,257							
16 Amortization	49,697	49,697	49,697	49,697							
17 Property Tax	59,947	59,947	59,947	59,947							
18 Payroll Tax	14,187	14,187	14,187	14,187							
19 Other Taxes	1,798	1,798	1,798	1,798							
20 Franchise Fees	46,535	46,548	46,809	46,796	(275)	(2)	(26)	(5)	(70)	(6)	(29)
21 Utility Income Tax	59,043	59,044	62,984	62,983	(3,941)	(0)	(1)	(0)	(781)	(0)	(1)
22 Total Operating Expenses & Taxes	1,552,464	1,552,971	1,557,256	1,556,746	(4,792)	(73)	(1,027)	(201)	(871)	(245)	(1,139)
23 **Utility Operating Income**	299,651	299,652	305,644	305,643	(5,993)	(0)	(3)	(1)	(1,858)	(1)	(3)
	299,651	299,652	305,644	305,643							
24 **Average Rate Base**											
25 Avg. Gross Plant	8,705,924	8,705,924	8,705,924	8,705,924					(25,500)		
26 Avg. Accum. Deprec. / Amort	(4,219,464)	(4,219,464)	(4,219,464)	(4,219,464)					491		
27 Avg. Accum. Def Tax	(591,970)	(591,970)	(591,970)	(591,970)					323		
28 Avg. Accum. Def ITC	-	-	-	-							
29 **Avg. Net Utility Plant**	3,894,490	3,894,490	3,894,490	3,894,490	-	-	-	-	(24,686)	-	-
30 Misc. Deferred Debits	26,623	26,623	26,623	26,623							
31 Operating Materials & Fuel	79,458	79,458	79,458	79,458							
32 Misc. Deferred Credits	(70,321)	(70,321)	(70,321)	(70,321)							
33 Working Cash	56,325	56,343	56,499	56,480	(174)	(3)	(37)	(7)	(32)	(9)	(41)
34 **Average Rate Base**	3,986,575	3,986,593	3,986,749	3,986,730	(174)	(3)	(37)	(7)	(24,718)	(9)	(41)
35 **Rate of Return**	7.517%	7.517%	7.667%	7.667%							
36 **Implied Return on Equity**	9.600%	9.600%	9.900%	9.900%							

37 Effective Cost of Debt	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	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%	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%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	0.000%	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%	50.000%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%
47 Bad Debt Rate	0.4032%	0.4300%	0.4300%	0.4032%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%
48 Franchise Fee Rate	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%
49 Working Cash Factor	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658
51 ROE Target	9.600%	9.600%	9.900%	9.900%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%
52 Grossed-Up COC	10.675%	10.675%	10.924%	10.924%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%
53 OPUC Fee Rate	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%
Utility Income Taxes											
54 Book Revenues	1,852,115	1,852,623	1,862,900	1,862,388	(10,785)	(73)	(1,030)	(201)	(2,729)	(246)	(1,142)
55 Book Expenses	1,493,421	1,493,928	1,494,272	1,493,763	(851)	(72)	(1,026)	(201)	(91)	(245)	(1,138)
56 Interest Deduction	108,295	108,296	108,300	108,300	(5)	(0)	(1)	(0)	(671)	(0)	(1)
57 Production Deduction	-	-	-	-							
58 Permanent Ms	(23,836)	(23,836)	(23,836)	(23,836)							
59 Deferred Ms	92,595	92,595	92,595	92,595							
60 Taxable Income	181,640	181,641	191,569	191,567	(9,929)	(0)	(3)	(1)	(1,967)	(1)	(3)
61 Current State Tax	13,100	13,100	13,816	13,816	(716)	(0)	(0)	(0)	(142)	(0)	(0)
62 State Tax Credits	(992)	(992)	(992)	(992)							
63 Net State Taxes	12,108	12,108	12,824	12,824	(716)	(0)	(0)	(0)	(142)	(0)	(0)
64 Federal Taxable Income	169,531	169,533	178,744	178,743	(9,213)	(0)	(3)	(1)	(1,825)	(1)	(3)
65 Current Federal Tax	59,336	59,336	62,561	62,560	(3,225)	(0)	(1)	(0)	(639)	(0)	(1)
66 Federal Tax Credits	(49,150)	(49,150)	(49,150)	(49,150)							
67 ITC Amort	-	-	-	-							
68 Deferred Taxes	36,749	36,749	36,749	36,749	-	-	-	-	-	-	-
69 Total Income Tax Expense	59,043	59,044	62,984	62,983	(3,941)	(0)	(1)	(0)	(781)	(0)	(1)
73 Regulated Net Income	191,356	191,356	197,344	197,343	(5,988)	(0)	(2)	(0)	(1,186)		

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Non-NVPC Adjustment Detail

	7/9/2015 Settlement				UP 310					Total
	Partial Settlement	ICNU Rate Base	CUB Other Rev	All Parties Return	CoP Pole and Circuit Sale	Blank	Blank	Blank	Blank	**Non-NVPC Adjustments**
1 Sales to Consumers	(9,303)	(2,068)	(1,552)	(4,000)	(104)	-	-	-	-	(33,234)
2 Sales for Resale										-
3 Other Revenues			1,500							1,500
4 Total Operating Revenues	(9,303)	(2,068)	(52)	(4,000)	(104)	-	-	-	-	(31,734)
5 Net Variable Power Costs										-
6 Production O&M (Excludes Trojan)										-
7 Trojan O&M										-
8 Transmission O&M										-
9 Distribution O&M										-
10 Customer & MBC O&M										(307)
11 Uncollectibles Expense	(38)	(8)	(6)	(16)	(0)	-	-	-	-	(91)
12 OPUC Fees	(35)	(8)	(6)	(15)	(0)	-	-	-	-	(84)
13 A&G, Ins/Bene., & Gen. Plant	(8,000)			-						(10,286)
14 Total Operating & Maintenance	(8,072)	(16)	(12)	(31)	(1)	-	-	-	-	(10,758)
15 Depreciation				-						-
16 Amortization				(3,852)						(3,852)
17 Property Tax										-
18 Payroll Tax										-
19 Other Taxes				-						-
20 Franchise Fees	(237)	(53)	(40)	(102)	(3)	-	-	-	-	(572)
21 Utility Income Tax	(294)	(591)	(0)	(5)	(30)	-	-	-	-	(1,704)
22 Total Operating Expenses & Taxes	(8,603)	(660)	(52)	(3,989)	(33)	-	-	-	-	(16,895)
23 **Utility Operating Income**	(700)	(1,407)	(0)	(11)	(71)	-	-	-	-	(14,840)
24 **Average Rate Base**										
25 Avg. Gross Plant	(9,000)	(18,700)			(1,996)					(55,196)
26 Avg. Accum. Deprec. / Amort					998					1,489
27 Avg. Accum. Def Tax					54					377
28 Avg. Accum. Def ITC										-
29 **Avg. Net Utility Plant**	(9,000)	(18,700)	-	-	(944)	-	-	-	-	(53,330)
30 Misc. Deferred Debits										-
31 Operating Materials & Fuel										-
32 Misc. Deferred Credits										-
33 Working Cash	(312)	(24)	(2)	(145)	(1)	-	-	-	-	(613)
34 **Average Rate Base**	(9,312)	(18,724)	(2)	(145)	(945)	-	-	-	-	(53,943)
35 **Rate of Return**										
36 **Implied Return on Equity**										

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37 Effective Cost of Debt	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%
38 Effective Cost of Preferred	0.000%	0.000%	0.000%	0.000%	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%	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%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%
42 Weighted Cost of Preferred	0.000%	0.000%	0.000%	0.000%	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%	50.000%	50.000%	50.000%	50.000%
44 State Tax Rate	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%
47 Bad Debt Rate	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%
48 Franchise Fee Rate	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%
49 Working Cash Factor	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658	1.658
51 ROE Target	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%
52 Grossed-Up COC	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%
53 OPUC Fee Rate	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%	0.3750%
Utility Income Taxes										
54 Book Revenues	(9,303)	(2,068)	(52)	(4,000)	(104)	-	-	-	-	(31,734)
55 Book Expenses	(8,309)	(69)	(52)	(3,985)	(3)	-	-	-	-	(15,191)
56 Interest Deduction	(253)	(509)	(0)	(4)	(26)	-	-	-	-	(1,465)
57 Production Deduction										-
58 Permanent Ms										-
59 Deferred Ms										-
60 Taxable Income	(741)	(1,490)	(0)	(12)	(75)	-	-	-	-	(15,078)
61 Current State Tax	(53)	(107)	(0)	(1)	(5)	-	-	-	-	(1,087)
62 State Tax Credits										-
63 Net State Taxes	(53)	(107)	(0)	(1)	(5)	-	-	-	-	(1,087)
64 Federal Taxable Income	(688)	(1,383)	(0)	(11)	(70)	-	-	-	-	(13,991)
65 Current Federal Tax	(241)	(484)	(0)	(4)	(24)	-	-	-	-	(4,897)
66 Federal Tax Credits										-
67 ITC Amort										-
68 Deferred Taxes	-	-	-	-	-	-	-	-	-	-
69 Total Income Tax Expense	(294)	(591)	(0)	(5)	(30)	-	-	-	-	(5,984)
73 Regulated Net Income	(447)	(899)	(0)	(7)				-		(13,374)

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NVPC Adjustment Detail

	4/1/2015 NVPC Update (1)	7/15/2015 NVPC Update (2)	8/12/2015 Settlement Update	10/1/2015 NVPC Update (3)	11/5/2015 NVPC Update (3)	11/16/2015 NVPC Update (3)	**Total NVPC Adjustments**
1 Sales to Consumers	(5,155)	(2,318)	(10,234)	(2,338)	-	-	(20,045)
2 Sales for Resale							-
3 Other Revenues							-
4 Total Operating Revenues	(5,155)	(2,318)	(10,234)	(2,338)	-	-	(20,045)
5 Net Variable Power Costs	(4,964)	(2,232)	(9,854)	(2,251)	-	-	(19,301)
6 Production O&M (Excludes Trojan)							-
7 Trojan O&M							-
8 Transmission O&M							-
9 Distribution O&M							-
10 Customer & MBC O&M							-
11 Uncollectibles Expense	(21)	(9)	(41)	(9)	-	-	(81)
12 OPUC Fees	(19)	(9)	(38)	(9)	-	-	(75)
13 A&G, Ins/Bene., & Gen. Plant							-
14 Total Operating & Maintenance	(5,004)	(2,250)	(9,934)	(2,269)	-	-	(19,457)
15 Depreciation							-
16 Amortization							-
17 Property Tax							-
18 Payroll Tax							-
19 Other Taxes							-
20 Franchise Fees	(131)	(59)	(261)	(60)	-	-	(511)
21 Utility Income Tax	(6)	(3)	(12)	(3)	-	-	(23)
22 Total Operating Expenses & Taxes	(5,141)	(2,312)	(10,206)	(2,331)	-	-	(19,990)
23 **Utility Operating Income**	(14)	(6)	(28)	(6)	-	-	(55)
24 **Average Rate Base**							
25 Avg. Gross Plant							-
26 Avg. Accum. Deprec. / Amort							-
27 Avg. Accum. Def Tax							-
28 Avg. Accum. Def ITC							-
29 **Avg. Net Utility Plant**	-	-	-	-	-	-	-
30 Misc. Deferred Debits							-
31 Operating Materials & Fuel							-
32 Misc. Deferred Credits							-
33 Working Cash	(187)	(84)	(370)	(85)	-	-	(725)
34 **Average Rate Base**	(187)	(84)	(370)	(85)	-	-	(725)
35 **Rate of Return**	7.516%						7.516%
36 **Implied Return on Equity**	9.600%						9.600%

37 Effective Cost of Debt	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%	5.433%
38 Effective Cost of Preferred	0.000%	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%	50.000%
40 Preferred Share of Cap Structure	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
41 Weighted Cost of Debt	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%	2.717%
42 Weighted Cost of Preferred	0.000%	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%	50.000%
44 State Tax Rate	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%	7.212%
45 Federal Tax Rate	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%	35.000%
46 Composite Tax Rate	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%	39.688%
47 Bad Debt Rate	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%	0.403%
48 Franchise Fee Rate	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%	2.547%
49 Working Cash Factor	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%	3.628%
50 Gross-Up Factor	1.658	1.658	1.658	1.658	1.658	1.658	1.658
51 ROE Target	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%	9.600%
52 Grossed-Up COC	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%	10.675%
53 OPUC Fee Rate	0.375%	0.375%	0.375%	0.375%	0.375%	0.375%	0.375%
Utility Income Taxes							
54 Book Revenues	(5,155)	(2,318)	(10,234)	(2,338)	-	-	(20,045)
55 Book Expenses	(5,135)	(2,309)	(10,194)	(2,329)	-	-	(19,968)
56 Interest Deduction	(5)	(2)	(10)	(2)	-	-	(20)
57 Production Deduction							-
58 Permanent Ms							-
59 Deferred Ms							-
60 Taxable Income	(15)	(7)	(29)	(7)	-	-	(58)
61 Current State Tax	(1)	(0)	(2)	(0)	-	-	(4)
62 State Tax Credits							-
63 Net State Taxes	(1)	(0)	(2)	(0)	-	-	(4)
64 Federal Taxable Income	(14)	(6)	(27)	(6)	-	-	(54)
65 Current Federal Tax	(5)	(2)	(10)	(2)	-	-	(19)
66 Federal Tax Credits							-
67 ITC Amort							-
68 Deferred Taxes	-	-	-	-	-	-	-
69 Total Income Tax Expense	(6)	(3)	(12)	(3)	-	-	(23)
73 Regulated Net Income	(9)	(4)	(18)	(4)	-	-	(35)

Category A Advertising
Adjust Result to 1/8 of 1% per OAR

9090001 CustSvc-InformAdvertisingExp	2,113,423
Less: Legally Mandated Advertising	25,750
	2,087,673
2016 Total Revenue Requirement	1,868,555
Factor per OAR	0.125%
Presumed Reasonable Cat A Costs	2,335,693
Total Adjustment	-