Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● jog@dvclaw.com
Suite 400
333 SW Taylor
Portland, OR 97204

June 16, 2017

Via Electronic Filing and Federal Express

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

Re: In the Matter of PORTLAND GENERAL ELECTRIC CO.
2017 Request for a General Rate Revision
Docket No. UE 319

Dear Filing Center:

Please find enclosed the Opening Testimony and Exhibits of Michael P. Gorman (ICNU/200 through ICNU/221) and the redacted version of the Opening Testimony and Exhibits of Bradley G. Mullins (ICNU/300 – ICNU/304) on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

In accordance with OAR 860-001-0170(2) and per the Commission's request, ICNU is also providing the Commission with four (4) hard copy sets of Mr. Gorman's testimony and exhibits. The confidential portions of Mr. Mullins' testimony and exhibits are being handled pursuant to Order No. 17-057 and will follow to the Commission via Federal Express.

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

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the **Opening Testimony and Exhibits of Michael P. Gorman and the confidential portions of the Opening Testimony and Exhibits of Bradley G. Mullins** upon the parties shown below by mailing copies via First Class U.S. Mail, postage prepaid.

Dated at Portland, Oregon, this 16th day of June, 2017

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

CITIZENS' UTILITY BOARD OF OREGON
Robert Jenks **(C)**
Elizabeth Jones **(C)**
610 SW Broadway, Suite 400
Portland, OR 97205
bob@oregoncub.org
liz@oregoncub.org

SMALL BUSINESS UTILITY ADVOCATES
James Birkelund **(C)**
Small Business Utility Advocates
548 Market St., Suite 11200
San Francisco, CA 94104
james@utilityadvocates.org

Diane Henkels **(C)**
Cleantech Law Partners PC
420 SW Washington St., Suite 400
Portland, OR 97204
dhenkels@cleantechlaw.com

FRED MEYER
Kurt J. Boehm **(C)**
Jody Kyler Cohn
Boehm Kurtz & Lowry
36 E. Seventh St., Suite 1510
Cincinnati, OH 45202
kboehm@bkllawfirm.com
jkyler@bkllawfirm.com

PUC STAFF - DEPARTMENT OF JUSTICE
Stephanie S. Andrus **(C)**
Sommer Moser **(C)**
PUC Staff – Dept. of Justice
Business Activities Section
1162 Court St. NE
Salem, OR 97301-4096
stephanie.andrus@state.or.us
sommer.moser@doj.state.or.us

PORTLAND GENERAL ELECTRIC COMPANY
Stefan Brown **(C)**
Jay Tinker **(C)**
121 SW Salmon
1WTC-0306
Portland, OR 97204
stefan.brown@pgn.com
pge.opuc.filings@pgn.com

CALPINE ENERGY
Gregory M. Adams **(C)**
Richardson Adams, PLLC
P.O. Box 7218
Boise, ID 83702
greg@richardsonadams.com

WAL-MART
Vicki M. Baldwin **(C)**
Parson Behle & Latimer
201 S. Main St., Suite 1800
Salt Lake City, UT 84111
vbaldwin@parsonbehle.com

Steve W. Chriss **(C)**
Wal-Mart Stores, Inc.
2001 SE 10th St.
Bentonville, AR 72716
stephen.chriss@wal-mart.com

CALPINE ENERGY
Kevin Higgins **(C)**
Energy Strategies LLC
215 State St., Suite 200
Salt Lake City, UT 84111-2322
khiggins@energystrat.com

Greg Bass
Calpine Energy Solutions, LLC
401 West A St., Suite 500
San Diego, CA 92101
greg.bass@calpinesolutions.com

PACIFICORP
Matthew McVee
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232
matthew.mcvee@pacificorp.com

OPUC STAFF
Marianne Gardner **(C)**
OPUC
P.O. Box 1088
Salem, OR 97308-1088
marianne.gardner@state.or.us

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

OPENING TESTIMONY OF MICHAEL P. GORMAN

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 16, 2017

TABLE OF CONTENTS TO THE OPENING TESTIMONY OF MICHAEL P. GORMAN

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017. I am employed by the firm of Brubaker & Associates, Inc. ("BAI"), regulatory and economic consultants with corporate headquarters in Chesterfield, Missouri. My qualifications are provided in Exhibit ICNU/201.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including Portland General Electric Company ("PGE" or the "Company").

Q. WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A. My testimony will address PGE's overall rate of return including return on equity, embedded debt cost, and capital structure. I will also respond to PGE witness Dr. Bente Villadsen.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibits ICNU/201 through ICNU/221.

I. SUMMARY

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS AND CONCLUSIONS ON RATE OF RETURN.

A. I recommend the Public Utility Commission of Oregon ("Commission") award a return on common equity of 9.25%, which is the midpoint of my recommended range of 8.90% to 9.60%. My recommended return on equity will fairly compensate PGE for its current market cost of common equity, and it will mitigate PGE's claimed revenue deficiency in this proceeding while providing a return that fairly balances the interests of customers and shareholders.

I recommend the Company's proposed use of a 50% debt and 50% common equity hypothetical ratemaking capital structure based on a rounding of its 2018 projected balances of long-term debt and common equity be rejected. Instead, I recommend the capital structure be set at the actual weights of the Company's projected 2018 capital structure mix which includes a 51.35% component of debt, and 48.65% component of common equity.

The overall rate of return produced by my recommended return on common equity, and ratemaking capital structure for PGE produces an overall rate of return of 7.16%, as shown on my Exhibit ICNU/202.

Finally, the Company requested a return on equity of 9.75% based on the studies supported by PGE witness Dr. Bente Villadsen. Dr. Villadsen's recommended range of 9.3% to 10.3% is excessive and unreasonable, and her point estimate of 9.8% substantially overstates a fair and reasonable return on equity for PGE in this proceeding.

II. RATE OF RETURN

Q. PLEASE DESCRIBE THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I will explain the analysis I performed to determine the reasonable rate of return in this proceeding and present the results of my analysis. I begin my estimate of a fair return on equity by reviewing the authorized returns approved by the regulatory commissions in various jurisdictions, the market assessment of the regulated utility industry investment risk, credit standing, and stock price performance. I used this information to get a sense of the market's perception of the risk characteristics of regulated utility investments in general, which is then used to produce a refined estimate of the market's return requirement for assuming investment risk similar to PGE's utility operations.

As described below, I find the credit rating outlook of the industry to be strong, supportive of the industry's financial integrity and access to capital. Further, regulated utilities' stocks have exhibited strong price performance over the last several years, which is evidence of utility access to capital.

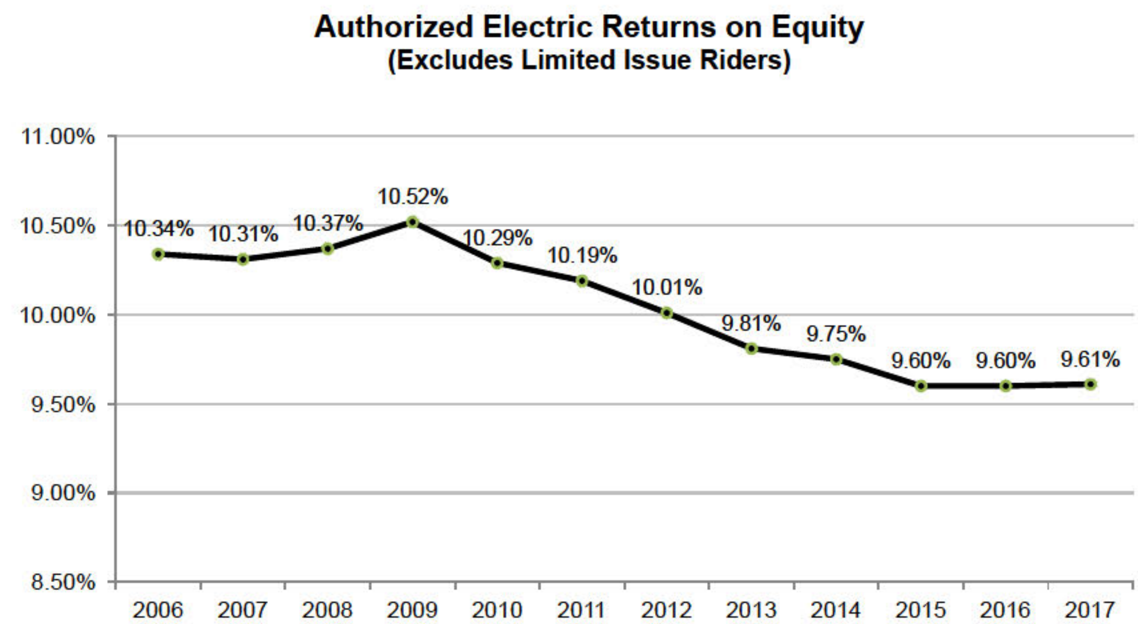
Based on this review of credit outlooks and stock price performance, I conclude that the market continues to embrace the regulated utility industry as a safe-haven investment and views utility equity and debt investments as low-risk securities.

II.A. ELECTRIC INDUSTRY AUTHORIZED RETURNS ON EQUITY, ACCESS TO CAPITAL, AND CREDIT STRENGTH

Q. PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED RETURNS ON EQUITY FOR ELECTRIC UTILITIES, UTILITIES' CREDIT STANDING, AND UTILITIES' ACCESS TO CAPITAL TO FUND INFRASTRUCTURE INVESTMENT.

A. Authorized returns on equity for both electric utilities have been steadily declining over the last 10 years, as illustrated in Figure 1 below. More recent authorized returns on equity for electric utilities have declined down to about 9.60%. This trend continues during the first quarter of 2017.

FIGURE 1



Source and Note:
Regulatory Research Associates, Inc., Regulatory Focus, Major Rate Case Decisions -- January - March 2017, April 20, 2017 at page 6.

While the declines in authorized returns on equity are public knowledge, and align with declining capital market costs, utilities are maintaining a stable investment grade credit outlook, and have been able to attract large amounts of capital at low costs to fund very large capital programs.

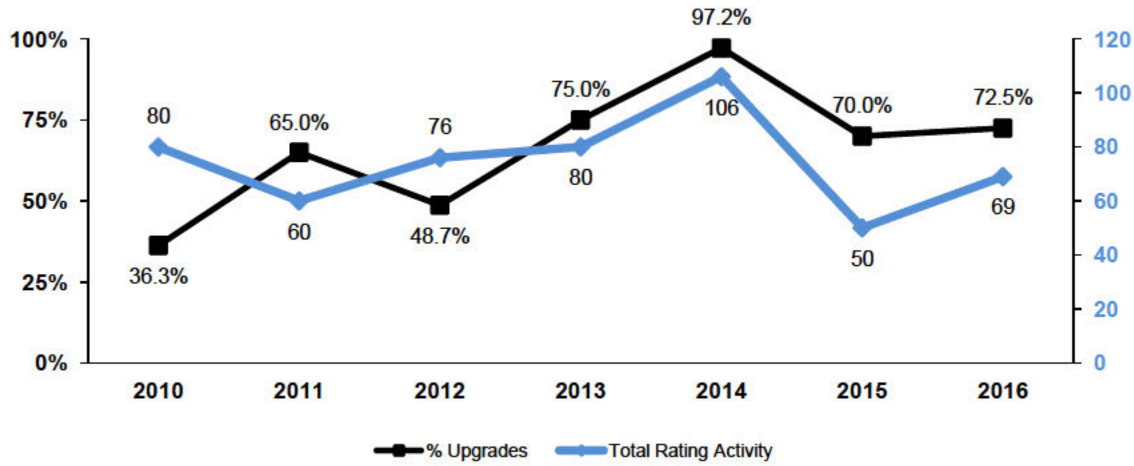
Q. PLEASE DESCRIBE THE TREND IN CREDIT RATING CHANGES IN THE ELECTRIC UTILITY INDUSTRY OVER THE LAST SEVERAL YEARS.

A. As shown in Figure 2 below, over the period 2010-2016, the electric utility industry has experienced a significant number of upgrades in credit ratings by all of the major credit rating agencies (Fitch Ratings, Moody's, and Standard & Poor's).

FIGURE 2

Credit Rating Changes
(U.S. Shareholder-Owned Electric Utility Industry)

	2010	2011	2012	2013	2014	2015	2016
Upgrades	29	39	37	60	103	35	50
Downgrades	51	21	39	20	3	15	19
% Upgrades	36.3%	65.0%	48.7%	75.0%	97.2%	70.0%	72.5%
Total Rating Activity	**80**	**60**	**76**	**80**	**106**	**50**	**69**



Source: EEI 2016 Q4 Credit Ratings. Tab IV. Direction of Rating Action.

As noted above in Figure 2, the upgrades in utility credit ratings started outpacing downgrades in 2011, and more recently, the number of upgrades has substantially exceeded the number of downgrades. For example, in 2014, there were 103 upgrades and only three downgrades. In 2015, the number of upgrades was more than twice the number of downgrades (35 upgrades and 15 downgrades). This trend was even more profound in 2016.

Q. HOW DID THIS CREDIT RATING ACTIVITY IMPACT THE CREDIT RATING OF THE ELECTRIC UTILITY INDUSTRY?

A. The credit rating changes for the electric utility industry reflected a significant strengthening of the electric utility industry credit rating as shown below in Table 1. As shown in this table, in 2008, approximately 69% of the electric utility industry was rated from BBB- to BBB+, 18% had a bond rating better than BBB+, and around 13% of the industry was below investment grade. This industry rating improved steadily over the subsequent eight years. By 2016, only about 3% of the industry was below investment grade, around 65% continued to be in the range of BBB- to BBB+, and over 32% of the industry had a bond rating of A- or higher. Overall, the improvement to the credit rating of the electric utility industry has been very significant.

TABLE 1

S&P Ratings by Category
(Year End)

Description	2008	2009	2010	2011	2012	2013	2014	2015	2016
Regulated									
A or higher	8%	7%	9%	8%	6%	3%	3%	3%	5%
A-	10%	15%	14%	14%	17%	20%	21%	22%	27%
BBB+	23%	22%	17%	19%	14%	17%	32%	33%	35%
BBB	23%	27%	31%	35%	36%	49%	37%	33%	22%
BBB-	23%	20%	17%	14%	17%	6%	3%	3%	8%
Below BBB-	13%	10%	11%	11%	11%	6%	5%	6%	3%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: EEI 2016 Q4 Credit Ratings. Tab V. S&P Rating by Comp. Category.

Moody's comments on this improved credit standing of regulated utility companies in its publication, "Regulation Remains a Credit Supportive Ratings Driver Two Years After Sector-Wide Upgrades." Moody's stated as follows:

> **Summary**
>
> In January and February 2014, we upgraded the ratings of 147 US regulated electric and gas utility debt issuers as part of a sector-wide rating action that reflected <u>our more favorable view of the relative credit supportiveness of US utility regulation</u>. Factors supporting this view include better cost-recovery provisions, reduced regulatory lag, and <u>generally fair and open relationships</u> between utilities and their state regulators.[1/]

[1/] Moody's Investor Service: "U.S. Regulated Utilities: Regulation Remains a Credit Supportive Ratings Driver Two Years After Sector-Wide Upgrades," November 6, 2015, emphasis added.

Q. HAVE CREDIT RATING AGENCIES COMMENTED ON DECLINING AUTHORIZED RETURNS ON EQUITY?

A. Yes. Credit rating agencies recognize the declining trend in authorized returns and the expectation that regulators will continue lowering the returns for U.S. utilities while maintaining a stable credit profile. Specifically, Moody's states:

> **Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles**
>
> The credit profiles of US regulated utilities will remain intact over the next few years despite our expectation that regulators will continue to trim the sector's profitability by lowering its authorized returns on equity (ROE).[2/]

Further, in a recent report, Standard & Poor's ("S&P") states:

> **2. Earned returns will remain in line with authorized returns**
>
> Authorized returns on equity granted by U.S. utility regulators in rate cases this year have been steady at about <u>9.5%</u>. Utilities have been adept at earning at or very near those authorized returns in today's economic and fiscal environment. A slowly recovering economy, natural gas and electric prices coming down and then stabilizing at fairly low levels, and the same experience with interest rates have led to a perfect "non-storm" for utility ratepayers and regulators, with utilities benefitting alongside those important constituencies. Utilities have largely used this protracted period of favorable circumstances to consolidate and institutionalize the regulatory practices that support earnings and cash flow stability. We have observed and we project continued use of credit-supportive policies such as short lags between rate filings and final decisions, up-to-date test years, flexible and dynamic tariff clauses for major expense items, and alternative ratemaking approaches that allow faster rate recognition for some new investments.[3/]

Q. HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT INFRASTRUCTURE CAPITAL PROGRAMS?

A. Yes. While cost of capital and authorized returns on equity were declining, the utility industry has been able to fund substantial increases in capital investments needed for

---

2/ *Moody's Investors Service*, "US Regulated Utilities: Lower Authorized Equity Returns Will Not Hurt Near-Term Credit Profiles," March 10, 2015.

3/ *Standard & Poor's Ratings Services*: "Corporate Industry Credit Research: Industry Top Trends 2016, Utilities," December 9, 2015, at 23, emphasis added.

infrastructure modernization and expansion. The Edison Electric Institute ("EEI") reported in a 2015 financial review of the electric industry financial performance that electric "industry-wide capex has more than doubled since 2005."[4/]

EEI also observed that, despite this significant increase in capital expenditures during the period 2005-2015, a majority of the funding for utilities' capital expenditures has been provided by internal funds. EEI reports approximately 25% of funding needed to meet these increasing capital expenditures has been derived from external sources and 75% of these capital expenditures have been funded by internal cash. Further, despite nearly tripling capital expenditures, the electric utility industry debt interest expense has declined by approximately 1.9% despite increases in the amount of outstanding debt (and reductions to the cost of debt).[5/] This is clear evidence that utilities have enjoyed access to large amounts of capital, and that the costs of capital have declined with declining market capital costs.

Similarly, in its March 21, 2017 Capital Expenditure Update report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several recent comments about utility capital investments:

> Capital expenditures throughout the U.S. power and gas sectors in 2017 are projected to reach an all-time high of $117.5 billion. The nation's largest electric and gas utilities are investing in infrastructure to comply with sweeping environmental regulations, implement new technologies, build new natural gas, solar and wind generation and upgrade aging transmission and distribution systems. Moreover, their near-term capital spending forecasts continue to escalate …. Total CapEx in 2016 for the companies in the RRA utility universe was $110.3 billion. We expect considerable levels of spending to serve as the basis for solid profit

---

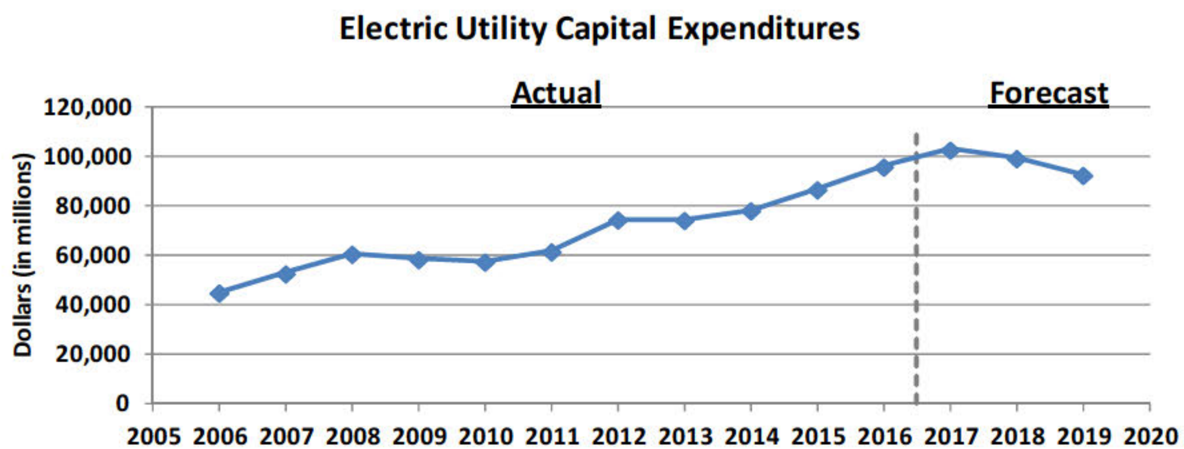
4/ Edison Electric Institute, *2015 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry*, at 17.

5/ *Id.* at 8-11.

> expansion for the foreseeable future, although our data indicates that CapEx in the industry may fall modestly in 2018 and 2019.[6/]

Indeed, historical versus projected outlooks for the electric industry's capital investments are shown in Figure 3 below. As shown in this graph, electric industry investment outlooks are expected to be considerably higher relative to the last 10-year historical period. As noted by S&P Global Market Intelligence, this capital investment is exceeding internal sources of funds to the electric utilities, requiring them to seek external capital to fund capital investments.

FIGURE 3



Source: *S&P Global Market Intelligence, Financial Focus*, Capital Expenditure Update, March 21, 2017, Page 7

Q. IS THERE EVIDENCE OF ROBUST VALUATIONS OF ELECTRIC UTILITY EQUITY SECURITIES?

A. Yes. On my Exhibit ICNU/203, I show the historical valuation of the electric utility industry followed by *Value Line* based on price-to-earnings ratio, price-to-cash flow ratio and market price-to-book value ratio indicators. These electric utility industry security

6/ S&P Global Market Intelligence, RRA Financial Focus: "Capital Expenditure Update," March 21, 2017, at 1.

valuation metrics show that current electric utility stock valuations are very strong and robust relative to the last 15 years. These robust valuations are an indication that utilities can sell equity securities at high prices, which is a strong indication that they can access capital under reasonable terms and conditions, and at relatively low cost.

Q. HOW SHOULD THE COMMISSION USE THIS MARKET INFORMATION IN ASSESSING A FAIR RETURN FOR PGE?

A. Market evidence is quite clear that capital market costs are near historically low levels. Authorized returns on equity have fallen to the low to mid 9.0% area; utilities continue to have access to large amounts of external capital to fund large capital programs; and utilities' investment grade credit standings are stable and have improved due, in part, to supportive regulatory treatment. The Commission should carefully weigh all this important observable market evidence in assessing a fair return on equity for PGE.

II.B. Regulated Utility Industry Market Outlook

Q. PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.

A. Regulated utilities' credit ratings have improved over the last few years and the outlook has been labeled "Stable" by credit rating agencies. Credit analysts have also observed that utilities have strong access to capital at attractive pricing (i.e., low capital costs), which has supported very large capital programs.

S&P recently published a report titled "Corporate Industry Credit Research: Industry Top Trends 2017, Utilities." In that report, S&P noted the following:

> **– Ratings Outlook**: Rating trends across regulated utilities remain mostly stable supported by stable regulatory oversight, slow but steady demand for utility services, and tempered by aggressive capital spending that will keep credit metrics from improving. Emerging new political trends in historically stable regions like Europe and the U.S. may have far-reaching effect on utilities over time, but S&P Global Ratings sees little immediate

> influence from those factors in 2017. Sovereign rating developments can influence utility ratings in some countries and we expect them to vary in different parts of the globe.
>
> * * *
>
> – **Assumptions:** Sales growth at most utilities is closely tied to the general economic outlook in its service territory, which can vary considerably from utility to utility. We project solid regulatory support for utility earnings and cash flow, with the occasional exception due to specific political or policy issues at the local level. Capital spending will continue to be elevated in most areas, with substantial infrastructure needs.
>
> * * *
>
> **– Industry Trends:** The utility industry in most regions is stable, consistent with our general ratings outlook and the nature of the essential products and services utilities sell.[7]

Similarly, Fitch states:

> **Stable Financial Performance:** The stable financial performance of Utilities, Power & Gas (UPG) issuers continues to support a sound credit profile for the sector, with 93% of the UPG portfolio carrying investment-grade ratings as of June 30, 2015, including 65% in the 'BBB' rating category. Second-quarter 2015 LTM [Long-Term Maturity] leverage metrics remained relatively unchanged year over year (YOY) while interest coverage metrics modestly improved. Fitch Ratings expects this trend to broadly sustain for the remainder of 2015, driven by positive recurring factors.[8]

Moody's recent comments on the U.S. Utility Sector state as follows:

> **2017 Outlook - Timely Cost-Recovery Drives Stable Outlook**
>
> Our outlook for the US regulated utilities industry is stable. This outlook reflects our expectations for the fundamental business conditions in the industry over the next 12 to 18 months.
>
> **A credit-supportive regulatory environment is the main driver of our stable outlook.** Our stable outlook for the US regulated utility industry is

[7] *Standard & Poor's Global Ratings*: "Industry Top Trends 2017, Utilities," February 16, 2017, at 1, emphasis added.

[8] *Fitch Ratings*: "U.S. Utilities, Power & Gas Data comparator," September 21, 2015, at 1 and 7, emphasis added.

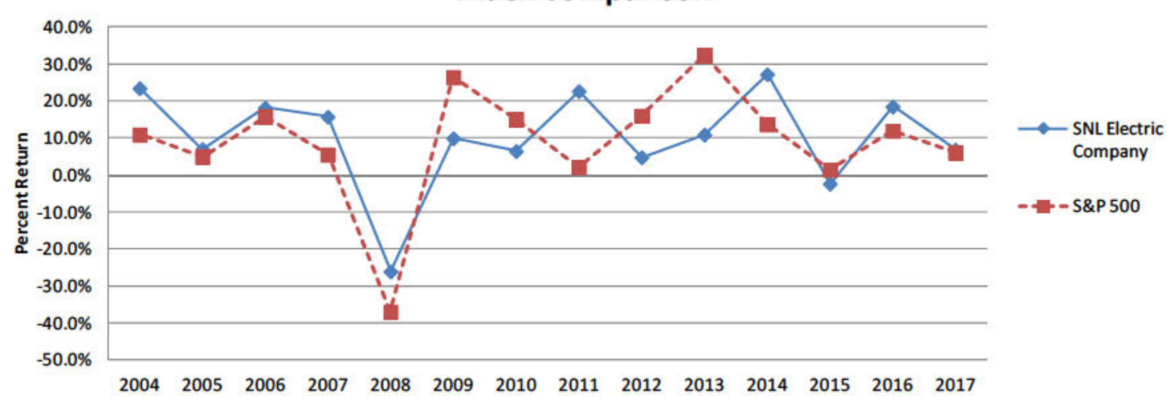
> based on our expectation that utilities will continue to recover costs in a timely manner and maintain stable cash flows.[9/]

Q. PLEASE DESCRIBE UTILITY STOCK PRICE PERFORMANCE OVER THE LAST SEVERAL YEARS.

A. As shown in Figure 4 below, SNL Financial has recorded utility stock price performance compared to the market. The industry's stock performance data from 2004 through the first quarter of 2017 shows that the SNL Electric Company Index has outperformed the market in downturns and trailed the market during recovery. This relatively stable price performance for utilities supports my conclusion that utility stock investments are regarded by market participants as a moderate- to low-risk investment.

FIGURE 4

Index Comparison



Source: SNL Financial.
Data through March 31, 2017

9/ *Moody's Investors Service*: "Regulated Utilities - US: 2017 Outlook – Timely Cost-Recovery Drives Stable Outlook," November 4, 2016, at 1, emphasis added.

Q. HAVE YOU CONSIDERED CONSENSUS MARKET OUTLOOKS FOR CHANGES IN INTEREST RATES IN FORMING YOUR RECOMMENDED RETURN ON EQUITY IN THIS CASE?

A. Yes. The outlook for changes in interest rates has been highly impacted by an expectation that the Federal Reserve Bank Open Market Committee ("FOMC") will raise short-term interest rates, and outlooks for inflation and GDP growth after the recent Presidential election. The market consensus economists are expecting continued increases in the Federal Funds rate as the FOMC continues to normalize interest rates in response to the strengthening of the U.S. economy.

This is evident from a comparison of current and forecasted changes in the Federal Funds rate, as shown in Table 2 below. However, while the Federal Funds rate is expected to increase dramatically over the next several years, consensus economists are not projecting significant increases in long-term interest rates. This is also illustrated in Table 2 below.

TABLE 2

Blue Chip Financial Forecasts
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index

Publication Date	3Q 2016	4Q 2016	1Q 2017	2Q 2017	3Q 2017	4Q 2017	1Q 2018	2Q 2018	3Q 2018
Federal Funds Rate									
Dec-16	**0.4**	0.5	0.7	0.8	1.0	1.1	1.3		
Jan-17		0.4	0.7	0.8	1.0	1.2	1.3	1.5	
Feb-17		**0.5**	0.7	0.8	1.0	1.1	1.3	1.6	
Mar-17		**0.5**	0.7	0.8	1.0	1.2	1.4	1.6	
Apr-17			0.7	0.9	1.1	1.3	1.5	1.7	1.9
May-17			**0.7**	1.0	1.2	1.3	1.5	1.7	1.9
Jun-17			**0.7**	1.0	1.2	1.4	1.5	1.7	1.9
T-Bond, 30 yr.									
Dec-16	**2.3**	2.8	3.0	3.1	3.2	3.3	3.4		
Jan-17		2.8	2.4	2.6	2.7	2.8	3.0	3.1	
Feb-17		**2.8**	3.1	3.2	3.4	3.5	3.6	3.7	
Mar-17		**2.8**	3.1	3.2	3.3	3.5	3.6	3.7	
Apr-17			3.1	3.2	3.3	3.5	3.6	3.7	3.8
May-17			**3.0**	3.1	3.3	3.4	3.5	3.6	3.7
Jun-17			**3.0**	3.0	3.2	3.4	3.5	3.6	3.7
GDP Price Index									
Dec-16	**1.5**	2.1	1.9	2.1	2.1	2.1	2.2		
Jan-17		2.1	2.0	2.1	2.1	2.1	2.2	2.2	
Feb-17		**2.1**	2.0	2.1	2.0	2.1	2.1	2.2	
Mar-17		**2.1**	2.2	2.0	2.1	2.1	2.2	2.2	
Apr-17			2.2	1.9	2.1	2.2	2.3	2.2	2.2
May-17			**2.3**	1.7	2.1	2.1	2.2	2.2	2.2
Jun-17			**2.2**	1.5	2.0	2.1	2.2	2.1	2.2

Source and Note:
Blue Chip Financial Forecasts, December 2016 through June 2017.
Actual Yields in Bold

I note that the three increases in the Federal Funds rate experienced over the last 16 months have not caused comparable changes in outlooks for changes in long-term interest rates. This is illustrated on my attached Exhibit ICNU/204. As shown on that exhibit, the actions taken by the FOMC to increase the Federal Funds rate has simply flattened the yield curve, and have not resulted in an increase in long-term interest rates. This is significant because cost of common equity is impacted by long-term interest rates, not short-term interest rates. As a result, these recent increases in the Federal Funds rate, and the expectation of continued increases in the Federal Funds rate, has not, and is not expected to, significantly impact long-term interest rates.

Another aspect of the Fed's impact on long-term interest rates is the amount of long-term Treasury notes and collateralized mortgage agreements the Fed has acquired and retained on its balance sheet. From November 2008 through October 2014, the Fed engaged in quantitative easing, purchasing large amounts of Treasury securities and collateralized mortgage agreements, including an extended period when the Fed was buying over $85 billion a month of these securities. Currently, the Fed has over $4.7 trillion of Treasury notes and collateralized mortgage agreements on its balance sheet. The Fed intends to reinvest cash flows produced by its balance sheet securities up until its normalization policies are reached, after which it will strategically start to liquidate the securities on its balance sheet. Concerning the impact on interest rates, *Blue Chip Financial Forecasts* describes Fed Chair Janet Yellen's comments as follows:

> She introduced another justification that we found interesting. She sees the effect of the Fed's enlarged balance sheet on the level of long-term interest rates as diminishing over time, and the waning effect of the portfolio on interest rates represents a passive tightening in policy. Specifically, she argued that the average maturity of the Fed's balance sheet is declining and thus its effect on long-term interest rates is lessening. From another perspective, the Fed's portfolio has been steady in the past two years because officials are merely reinvesting maturing and pre-paid securities. A steady portfolio translates to a diminishing share of a growing fixed-income market and therefore a smaller influence on interest rates.[10/]

[10/] *Blue Chip Financial Forecasts*, February 1, 2017 at 13.

Q. WHAT ARE THE IMPORTANT TAKEAWAY POINTS FROM THIS ASSESSMENT OF UTILITY INDUSTRY CREDIT AND INVESTMENT RISK OUTLOOKS?

A. Credit rating agencies consider the regulated utility industry to be "Stable" and believe investors will continue to provide an abundance of low-cost capital to support utilities' large capital programs at attractive costs and terms. All of this reinforces my belief that utility investments are generally regarded as safe-haven or low-risk investments and the market continues to demand low-risk investments such as utility securities. The ongoing demand for low-risk investments can reasonably be expected to continue to provide attractive low-cost capital for regulated utilities.

II.C. PGE Investment Risk

Q. PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF THE INVESTMENT RISK OF PGE.

A. The market's assessment of PGE's investment risk is described by credit rating analysts' reports. PGE's current corporate bond ratings from S&P and Moody's are BBB and A3, respectively.[11] The Company's outlook from both S&P and Moody's is "Stable."

S&P states:

> **Outlook: Stable**
>
> S&P Global Ratings' stable outlook on Portland General Electric Co. reflects our expectation that credit measures will not materially fall below the current average of about 19% funds from operations (FFO) to total debt. At the same time, we expect the ongoing cost recovery of the Carty generating unit through rates and incremental construction costs through rates or a surety bond.
>
> **Business Risk: Strong**
>
> Our assessment of Portland General's business risk profile incorporates the very low risk of the regulated utility industry that

[11] Exhibit PGE/1100, Villadsen/3 and Exhibit PGE/1000, Hager-Liddle/10.

> has material barriers to entry and essentially operates as a monopoly insulated from market challenges. The company has a constructive regulatory environment, a midsize customer base, and competitive rates across customer classes.
>
> * * *
>
> **Financial Risk: Significant**
>
> Our baseline forecast includes adjusted FFO to debt averaging around 19%, modestly above the mid-point of the benchmark range. The supplemental ratio of FFO cash interest coverage robustly supports this determination since in our base-case scenario we expect this measure to average 5.6x over the next few years.[12]

II.D. PGE'S PROPOSED CAPITAL STRUCTURE

Q. WHAT IS PGE'S PROPOSED CAPITAL STRUCTURE?

A. PGE's proposed capital structure is shown in Table 3 below:

TABLE 3

PGE's Proposed Capital Structure
(Test Year 2018)

Description	Weight
Long-Term Debt	50.00%
Common Equity	50.00%
Total Regulatory Capital Structure	100.00%

Source: Exhibit PGE/1000, Hager-Liddle/2.

PGE's proposed ratemaking capital structure is sponsored by its witnesses Patrick Hager and Christopher Liddle.

[12] Standard & Poor's RatingsDirect: "Summary: Portland General Electric Co.," April 7, 2017, emphasis added.

Q. DO YOU HAVE ANY COMMENTS IN REGARD TO PGE'S PROPOSED CAPITAL STRUCTURE?

A. Yes. The Company is proposing to set rates using a capital structure consisting of 50.0% debt and 50.0% equity capital for the projected 2018 test year. However, at page 2 of the testimony of Mr. Hager and Mr. Liddle, PGE's projected 2018 capital structure is comprised of a 51.35% long-term debt ratio and a 48.65% common equity ratio, as shown on my Exhibit ICNU/202. The Company's proposed ratemaking capital structure contains a higher percentage of common equity than the Company's projected 2018 test year capital structure.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S PROPOSED CAPITAL STRUCTURE?

A. I recommend PGE's projected test year capital structure be used to set rates. PGE's projected test year capital structure is composed of 48.65% common equity and 51.35% long-term debt.

This projected 2018 capital structure reasonably aligns with PGE's actual capital structure weights over the last five years. Hence, I believe the Company's projected 2018 capital structure's actual weights are reasonable, in line with historical actual capital structures over the last five years, and will support PGE's investment grade bond rating. Also, using the Company's projected test year capital structure will reduce its claimed revenue deficiency, because the projected test year capital structure has a lower amount of common equity than PGE's requested capital structure and, thus, will result in a lower overall rate of return, income tax and revenue requirement. The Company's projected 2018 capital structure will maintain its financial integrity and access to capital at a lower cost to retail customers.

Therefore, I believe it is more reasonable than the Company's proposed hypothetical weighted capital structure composed of 50% debt and 50% equity.

As such, I recommend PGE's projected 2018 test year capital structure as shown below in Table 4 be used to set rates in this proceeding.

TABLE 4

PGE's Proposed Capital Structure
(Test Year 2018)

Description	Weight
Long-Term Debt	51.35%
Common Equity	48.65%
Total Regulatory Capital Structure	100.00%

Sources: Exhibit PGE/1000, Hager-Liddle/2 and Exhibit ICNU/202.

II.E. EMBEDDED COST OF DEBT

Q. WHAT IS THE COMPANY'S EMBEDDED COST OF DEBT?

A. PGE is proposing an embedded cost of debt of 5.17% as developed on Exhibit PGE/1001, Hager-Liddle/1. I have used the Company's proposed cost of debt in my calculation of an overall weighted cost of capital.

II.F. RETURN ON EQUITY

Q. PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A. A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

Q. PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A. In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944).

These decisions identify the general financial and economic standards to be considered in establishing the cost of common equity for a public utility. Those general standards provide the authorized return should: (1) be sufficient to maintain financial integrity; (2) attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q. PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE PGE'S COST OF COMMON EQUITY.

A. I have used several models based on financial theory to estimate PGE's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Risk Premium model; and (5) a Capital Asset Pricing Model ("CAPM"). I have applied these models to a group of publicly traded utilities with investment risk similar to PGE.

II.G. Risk Proxy Group

Q. PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP TO ESTIMATE PGE'S CURRENT MARKET COST OF EQUITY.

A. I relied on the same proxy group developed by Company witness Dr. Villadsen. I believe that this proxy group can be used to reasonably reflect the investment risk of PGE.

Q. PLEASE DESCRIBE WHY YOU BELIEVE YOUR PROXY GROUP IS REASONABLY COMPARABLE IN INVESTMENT RISK TO PGE.

A. The proxy group is shown in Exhibit ICNU/205, The proxy group has an average corporate credit rating from S&P of BBB+, which is a notch higher than the credit rating of PGE of "BBB". The proxy group has an average corporate credit rating from Moody's of Baa1, which is a notch lower than PGE's credit ratings of "A3". Based on this information, I believe my proxy group is reasonably comparable in investment risk to PGE.

The proxy group has an average common equity ratio of 45.2% (including short-term debt) from SNL Financial ("SNL") and 48.2% (excluding short-term debt) from *The Value Line Investment Survey* ("*Value Line*") in 2016. PGE's test year projected capital structure has a common equity ratio of 48.65% which is comparable to the proxy group's long-term capital structure ratio of 48.2%. For these reasons, I conclude that the proxy group has comparable total investment risk to that of PGE.

II.H. Discounted Cash Flow Model

Q. PLEASE DESCRIBE THE DCF MODEL.

A. The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \; .\;.\;.\;. \; \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price

D = Dividends in periods 1 - ∞

K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return otherwise known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return

D_1 = Dividend in first year

P_0 = Current stock price

G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A. As shown in Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q. WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A. I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on May 19, 2017. An average stock price is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

A 13-week average stock price reflects a period that is still short enough to contain data that reasonably reflects current market expectations but the period is not so short as to be susceptible to market price variations that may not reflect the stock's long-term value. In my judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements.

Q. WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A. I used the most recently paid quarterly dividend as reported in *Value Line*.[13/] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

Q. WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A. There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' consensus about what the dividend, or earnings growth rate, will be and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[14/] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices than growth rates derived only from historical data.

13/ *The Value Line Investment Survey*, March 17, April 28, and May 19, 2017.

14/ *See, e.g.,* David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," *The Journal of Portfolio Management*, Spring 1989.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, SNL, and Reuters. All such projections were available on May 19, 2017, and all were reported online.

Each consensus growth rate projection is based on a survey of security analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not as reliably predict consensus investor outlooks as does a consensus of market analysts' projections. The consensus estimate is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analyst forecasts is a good proxy for market consensus expectations.

Q. WHAT ARE THE GROWTH RATES YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A. The growth rates I used in my DCF analysis are shown in Exhibit ICNU/206. The average growth rate for my proxy group is 5.37%.

Q. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A. As shown in Exhibit ICNU/207, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 8.80% and 8.87%, respectively.

Q. DO YOU HAVE ANY COMMENTS ON THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A. Yes. The constant growth DCF analysis for my proxy group is based on a group average long-term sustainable growth rate of 5.37%. The three- to five-year growth rates are higher than my estimate of a maximum long-term sustainable growth rate of 4.20%, which I discuss later in this testimony. I believe the constant growth DCF analysis produces a reasonable high-end return estimate from my DCF studies.

Q. HOW DID YOU ESTIMATE A MAXIMUM LONG-TERM SUSTAINABLE GROWTH RATE?

A. A long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. Hence, the long-term maximum sustainable growth rate for a utility investment is best proxied by the projected long-term Gross Domestic Product ("GDP"). *Blue Chip Financial Forecasts* projects that over the next 5 and 10 years, the U.S. nominal GDP will grow approximately 4.20%. These GDP growth projections reflect a real growth outlook of 2.1% and an inflation outlook of 2.1% going forward. As such, the average growth rate over the next 10 years is approximately 4.20%, which I believe is a reasonable proxy of long-term sustainable growth.[15/]

In my multi-stage growth DCF analysis, I discuss academic and investment practitioner support for using the projected long-term GDP growth outlook as a maximum sustainable growth rate projection. Hence, recognizing the long-term GDP growth rate as a maximum sustainable growth is logical, and is generally consistent with academic and economic practitioner accepted practices.

II.I. Sustainable Growth DCF

Q. PLEASE DESCRIBE HOW YOU ESTIMATED A SUSTAINABLE LONG-TERM GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A. A sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. These reinvested earnings increase the earnings base (rate base). Earnings grow when plant funded by reinvested

15/ *Blue Chip Financial Forecasts*, June 1, 2017, at 14.

earnings is put into service, and the utility is allowed to earn its authorized return on such additional rate base investment.

The internal growth methodology is tied to the percentage of earnings retained in the company and not paid out as dividends. The earnings retention ratio is 1 minus the dividend payout ratio. As the payout ratio declines, the earnings retention ratio increases. An increased earnings retention ratio will fuel stronger growth because the business funds more investments with retained earnings.

The payout ratios of the proxy group are shown in my Exhibit ICNU/208. These dividend payout ratios and earnings retention ratios then can be used to develop a sustainable long-term earnings retention growth rate. A sustainable long-term earnings retention ratio will help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit ICNU/209, the average sustainable growth rate for the proxy group using this internal growth rate model is 4.74%.

Q. WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE LONG-TERM GROWTH RATES?

A. A DCF estimate based on these sustainable growth rates is developed in Exhibit ICNU/210. As shown there, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 8.15% and 7.65%, respectively.

II.J. Multi-Stage Growth DCF Model

Q. HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A. Yes. My first constant growth DCF is based on consensus analysts' growth rate projections so it is a reasonable reflection of rational investment expectations over the next three to five years. The limitation on this constant growth DCF model is that it cannot reflect a rational expectation that a period of high or low short-term growth can be followed by a change in growth to a rate that is more reflective of long-term sustainable growth. Hence, I performed a multi-stage growth DCF analysis to reflect this outlook of changing growth expectations.

Q. WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A. Analyst-projected growth rates over the next three to five years will change as utility earnings growth outlooks change. Utility companies go through cycles in making investments in their systems. When utility companies are making large investments, their rate base grows rapidly, which in turn accelerates earnings growth. Once a major construction cycle is completed or levels off, growth in the utility rate base slows and its earnings growth slows from an abnormally high three- to five-year rate to a lower sustainable growth rate.

As major construction cycles extend over longer periods of time, even with an accelerated construction program, the growth rate of the utility will slow simply because rate base growth will slow and the utility has limited human and capital resources available to expand its construction program. Therefore, the three- to five-year growth rate projection should be used as a long-term sustainable growth rate but not without making a reasonable informed judgment to determine whether it considers the current market environment, the industry, and whether the three- to five-year growth outlook is sustainable.

Q. PLEASE DESCRIBE YOUR MULTI-STAGE GROWTH DCF MODEL.

A. The multi-stage growth DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage growth DCF model reflects three growth periods: (1) a short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 through perpetuity.

For the short-term growth period, I relied on the consensus analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate.

Q. WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A. Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. Utilities' earnings/dividend growth is created by increased utility investment or rate base. Such investment, in turn, is driven by service area economic growth and demand for utility service. In other words, utilities invest in plant to meet sales demand growth. Sales growth, in turn, is tied to economic growth in their service areas.

The U.S. Department of Energy, Energy Information Administration ("EIA") has observed utility sales growth tracks the U.S. GDP growth, albeit at a lower level, as shown in Exhibit ICNU/211. Utility sales growth has lagged behind GDP growth for more than a decade. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q. IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE GROWTH OF THE U.S. GDP?

A. Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but <u>dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation)</u>.[16/]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

> **Estimating Growth Rates**
>
> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation

[16/] "*Fundamentals of Financial Management*," Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298, emphasis added.

> and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[17/]

Q. IS THERE ANY ACTUAL INVESTMENT HISTORY THAT SUPPORTS THE NOTION THAT THE CAPITAL APPRECIATION FOR STOCK INVESTMENTS WILL NOT EXCEED THE NOMINAL GROWTH OF THE U.S. GDP?

A. Yes. This is evident by a comparison of the compound annual growth of the U.S. GDP compared to the geometric growth of the U.S. stock market. Morningstar measures the historical geometric growth of the U.S. stock market over the period 1926-2016 to be approximately 5.8%.[18/] During this same time period, the U.S. nominal compound annual growth of the U.S. GDP was approximately 6.4%.[19/]

As such, the compound geometric growth of the U.S. nominal GDP has been higher but comparable to the nominal growth of the U.S. stock market capital appreciation. This historical relationship indicates the U.S. GDP growth outlook is a conservative estimate of the long-term sustainable growth of U.S. stock investments.

Q. HOW DID YOU DETERMINE A SUSTAINABLE LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OUTLOOK OF THE MARKET?

A. I relied on the consensus analysts' projections of long-term GDP growth. *Blue Chip Financial Forecasts* publishes consensus economists' GDP growth projections twice a year. These consensus analysts' GDP growth outlooks are the best available measure of the market's assessment of long-term GDP growth. These analyst projections reflect all current outlooks for GDP and are likely the most influential on investors' expectations of

---

17/ *Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook* at 51 and 52.

18/ *Duff & Phelps, 2017 SBBI Yearbook* at 6-17.

19/ U.S. Bureau of Economic Analysis, February 28, 2017.

future growth outlooks. The consensus economists' published GDP growth rate outlook is 4.20% over the next five to 10 years.[20]

Therefore, I propose to use the consensus economists' projected 5- and 10-year average GDP consensus growth rates of 4.20%, as published by *Blue Chip Financial Forecasts*, as an estimate of long-term sustainable growth. *Blue Chip Financial Forecasts* projections provide real GDP growth projections of 2.1% and GDP inflation of 2.1%[21] over the 5-year and 10-year projection periods. These consensus GDP growth forecasts represent the most likely views of market participants because they are based on published consensus economist projections.

Q. DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A. Yes, and these sources corroborate my consensus analysts' projections, as shown below in Table 5.

20/ *Blue Chip Financial Forecasts*, June 1, 2017, at 14.

21/ *Id.*

TABLE 5

GDP Forecasts

Source	Term	Real GDP	Inflation	Nominal GDP
Blue Chip Financial Forecasts	5-10 Yrs	2.1%	2.1%	4.2%
EIA – Annual Earnings Outlook	29 Yrs	2.0%	2.1%	4.2%
Congressional Budget Office	6 Yrs	1.9%	2.0%	4.0%
Moody's Analytics	25 Yrs	2.0%	2.0%	4.0%
Social Security Administration	49 Yrs			4.4%
The Economist Intelligence Unit	25 Yrs	1.7%	1.9%	3.6%

The EIA in its *Annual Energy Outlook* projects real GDP out until 2050. In its 2017 Annual Report, the EIA projects real GDP through 2050 to be 2.0% and a long-term GDP price inflation projection of 2.1%. The EIA data supports a long-term nominal GDP growth outlook of 4.2%.[22/]

Also, the Congressional Budget Office ("CBO") makes long-term economic projections. The CBO is projecting real GDP growth to be 1.9% during the next 6 years with a GDP price inflation outlook of 2.0%. The CBO 6-year outlook for nominal GDP based on this projection is 4.0%.[23/]

Moody's Analytics also makes long-term economic projections. In its recent 25-year outlook to 2046, Moody's Analytics is projecting real GDP growth of 2.0% with

22/ DOE/EIA Annual Energy Outlook 2017 With Projections to 2050, downloaded March 1, 2017.

23/ *CBO: The Budget and Economic Outlook: 2017 to 2027*, January 2017, downloaded March 1, 2017.

GDP inflation of 2.0%. Based on these projections, Moody's is projecting nominal GDP growth of 4.0% over the next 25 years.[24/]

The Social Security Administration ("SSA") makes long-term economic projections out to 2090. The SSA's nominal GDP projection, under its intermediate cost scenario of 50 years, is 4.4%.[25/]

The Economist Intelligence Unit, a division of *The Economist* and a third-party data provider to SNL Financial, makes a long-term economic projection out to 2050. The Economist Intelligence Unit is projecting real GDP growth of 1.7% with an inflation rate of 1.9% out to 2050. The real GDP growth projection is in line with the consensus economists. The long-term nominal GDP projection based on these outlooks is approximately 3.6%.[26/]

The real GDP and nominal GDP growth projections made by these independent sources support the use of the consensus economists' 5-year and 10-year projected GDP growth outlooks as a reasonable estimate of market participants' long-term GDP growth outlooks.

Q. WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE GROWTH DCF ANALYSIS?

A. I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For stage one growth, I used the consensus analysts' growth rate projections discussed above in my constant growth DCF model. The first stage growth covers the first five years, consistent with the term of the analyst growth rate projections. The second stage, or transition stage, begins in year 6 and extends

24/ www.economy.com, *Moody's Analytics Forecast*, February 6, 2017.
25/ www.ssa.gov, "2016 OASDI Trustees Report," Table VI.G4, downloaded March 1, 2017.
26/ *SNL Financial, Economist Intelligence Unit,* downloaded on March 1, 2017.

through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.20% long-term sustainable growth rate based on the consensus economists' long-term projected nominal GDP growth rate.

Q. WHAT ARE THE RESULTS OF YOUR MULTI-STAGE GROWTH DCF MODEL?

A. As shown in Exhibit ICNU/212, the average and median DCF returns on equity for my proxy group using the 13-week average stock price are 7.93% and 7.85%, respectively.

Q. PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A. The results from my DCF analyses are summarized in Table 6 below:

TABLE 6

Summary of DCF Results

Description	Proxy Group Average	Proxy Group Median
Constant Growth DCF Model (Analysts' Growth)	8.80%	8.87%
Constant Growth DCF Model (Sustainable Growth)	8.15%	7.65%
Multi-Stage Growth DCF Model	7.93%	7.85%

I conclude that my DCF studies support a return on equity of 8.9%. I place primary reliance on my constant growth DCF result, which I find as a reasonable but high-end DCF return estimate. I have concerns with my constant growth DCF using a sustainable growth rate and my multi-stage growth DCF model because they produce results under 8%. I do not believe that a return on equity this low is reasonably consistent with market evidence of required risk premiums and security valuations. Therefore, my point estimate falls just at the approximate median of my constant growth DCF studies.

II.K. Risk Premium Model

Q. PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A. This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds. The difference between the required return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year over the period January 1986 through March 2017. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Authorized returns are typically based on expert witnesses' estimates of the contemporary investor-required return.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period January 1986 through March 2017 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit ICNU/213, which shows the market-to-book ratio since 1986 for the electric utility industry was consistently above a multiple of 1.0x. Over this period, regulatory authorized returns were sufficient to support market prices that at least exceeded book value. This is an indication that regulatory authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares, and, thus, utilities were able to access equity markets under reasonable terms.

Based on this analysis, as shown in Exhibit ICNU/214, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.50%. Since the risk premium can vary depending upon market conditions and changing investor risk perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I incorporated five-year and 10-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit ICNU/214, the five-year rolling average risk premium over Treasury bonds ranged from 4.25% to 6.72%, while the 10-year rolling average risk premium ranged from 4.38% to 6.50%.

As shown on my Exhibit ICNU/215, the average indicated equity risk premium over contemporary Moody's utility bond yields was 4.13%. The five-year and 10-year rolling average risk premiums ranged from 2.88% to 5.57% and 3.20% to 5.16%, respectively.

Q. DO YOU BELIEVE THAT THE TIME PERIOD USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES IS APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?

A. Yes. The time period I use in this risk premium study is a generally accepted period to develop a risk premium study using "expectational" data.

Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value is an indication the authorized returns on equity and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Alternatively, some studies, such as Duff & Phelps referred to later in this testimony, have recommended that use of "actual achieved investment return data" in a risk premium study should be based on long historical time periods. The studies find that achieved returns over short time periods may not reflect investors' expected returns due to unexpected and abnormal stock price performance. Short-term, abnormal actual returns would be smoothed over time and the achieved actual investment returns over long time periods would approximate investors' expected returns. Therefore, it is reasonable to assume that averages of annual achieved returns over long time periods will generally converge on the investors' expected returns.

My risk premium study is based on expectational data, not actual investment returns, and, thus, need not encompass a very long historical time period.

Q. HOW DID YOU USE THIS RISK PREMIUM STUDY TO ESTIMATE PGE'S COST OF COMMON EQUITY IN THIS PROCEEDING?

A. I used this information to measure an equity risk premium that reflects the current market or investor perception of investment risk in the utility industry today. I have gauged market/investor perceptions in utility risk today in Exhibit ICNU/216, where I show the yield spread between utility bonds and Treasury bonds over the last 37 years. As shown in this schedule, the average utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.51% and 1.95%, respectively. The utility bond yield spreads over Treasury bonds for "A" and "Baa" rated utilities for 2016 were 1.33% and 2.08%, respectively. The yield spreads for the first three months of 2017 were considerably lower, 1.14% (A) and 1.56% (Baa). The current average "A" rated utility bond yield spread over Treasury bond yields is now lower than the 37-year average spread. The current "Baa" rated utility bond yield spread over Treasury bond yields is also lower than the 37-year average spread.

These yield spreads show that utility capital costs are lower currently than they have been historically relative to treasury bond yields, and also that the bond yield spreads expand above historical norms as the investment risk of the security increases. This information allows for a informed determination of whether the current equity risk premiums in the market is above, below or at historical averages.

Q. HOW DO YOU DETERMINE WHERE A REASONABLE RISK PREMIUM IS IN THE CURRENT MARKET?

A. I observed the spread of Treasury securities relative to public utility bonds and corporate bonds in gauging whether or not the risk premium in current market prices is relatively stable relative to the past. What this observation of market evidence clearly provides is that the valuations in the current market place an above average risk premium on securities that have greater risk.

This market evidence is summarized below in Table 7, which shows the utility bond yield spreads over Treasury bond yields on average for the period 1980 through March 2017 and the spreads for 2016 and the first three months of 2017. I also show the corporate bond yield spreads for Aaa corporates and Baa corporates.

TABLE 7

Comparison of Yield Spreads Over Treasury Bonds

	Utility		Corporate	
Description	**A**	**Baa**	**Aaa**	**Baa**
2016	1.33%	2.08%	1.07%	2.12%
2017 YTD`	1.14%	1.56%	0.92%	1.62%
Average Historical Spread	1.51%	1.95%	0.84%	1.94%

Source: Exhibit ICNU/216.

The observable yield spreads shown in the table above illustrate securities of greater risk have above average risk premiums relative to the long-term historical average risk premium. Specifically, A-rated utility bonds to Treasuries, a relatively low-risk investment, have a yield spread in 2016 that has been very comparable to that of its long-term historical yield spread. The 2016 and 2017 A-rated utility bond yield spread is actually below the yield spread over the last 37 years. This is an indication that low risk investments like Aaa corporate bond yield and A-rated utility bond yield have premium values relative to minimal risk Treasury securities.

In contrast, the higher risk Baa utility and corporate bond yields currently have an above-average yield spread of approximately 20 basis points (2.08% vs. 1.95%) in 2016. The higher risk Baa utility bond yields do not have the same premium valuations as their lower risk A-rated utility bond yields, and thus the yield spread for greater risk investments is wider than lower risk investments. However, in the first three months of 2017, the yield spread is lower than the historical average.

This illustrates securities with greater risk, such as Baa yields versus A yields, are commanding above average risk premium spreads in the current marketplace. Utility equity securities are greater risk than Baa utility bonds. Because greater risk securities appear to support an above-average risk premium relative to historical averages, this would support an above-average risk premium in measuring a fair return on equity for a utility stock or equity security.

Q. WHAT IS YOUR RECOMMENDED RETURN FOR PGE BASED ON YOUR RISK PREMIUM STUDY?

A. To be conservative, I am recommending more weight to the high-end risk premium estimates than the low-end. I state this because of the relatively low level of interest rates now but relative upward movements of utility yields more recently. Hence, I propose to provide 75% weight to my high-end risk premium estimates and 25% to the low-end. Applying these weights, the risk premium for Treasury bond yields would be approximately 6.1%,[27/] which is considerably higher than the 31-year average risk premium of 5.50% and reasonably reflective of the 3.7% projected Treasury bond yield. A Treasury bond risk premium of 6.1% and projected Treasury bond yield of 3.7% produce a risk premium estimate of 9.80%. Similarly, applying these weights to the

27/ (4.25% * 25%) + (6.72% * 75%) = 6.10%.

utility risk premium indicates a risk premium of 4.9%.[28/] This risk premium is above the 31-year historical average risk premium of 4.13%. This risk premium in connection with the current Baa observable utility bond yield of 4.54% produces an estimated return on equity of approximately 9.40%.

Based on this methodology, my Treasury bond risk premium and my utility bond risk premium indicate a return in the range of 9.4% to 9.8%, with a midpoint of 9.6%.

II.L. Capital Asset Pricing Model ("CAPM")

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM method of analysis is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The stock-specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in the opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix, and production limitations).

28/ (2.88% * 25%) + (5.57% * 75%) = 4.90%.

The risks that cannot be eliminated when held in a diversified portfolio are non-diversifiable risks. Non-diversifiable risks are related to the market in general and referred to as systematic risks. Risks that can be eliminated by diversification are non-systematic risks. In a broad sense, systematic risks are market risks and non-systematic risks are business risks. The CAPM theory suggests the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk investors will be compensated for are systematic or non-diversifiable risks. The beta is a measure of the systematic or non-diversifiable risks.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A. The CAPM requires an estimate of the market risk-free rate, the Company's beta, and the market risk premium.

Q. WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A. As previously noted, *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield is 3.70%.[29/] The current 30-year Treasury bond yield is 2.99%, as shown in Exhibit ICNU/217. I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 3.70% for my CAPM analysis.

Q. WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A. Treasury securities are backed by the full faith and credit of the United States government so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate

---

[29/] *Blue Chip Financial Forecasts*, June 1, 2017, at 2.

(or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. A Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic of market risks. Consequently, for companies with betas less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q. WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A. As shown in Exhibit ICNU/218, the proxy group average *Value Line* beta estimate is 0.70.

Q. HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATE?

A. I derived two market risk premium estimates: a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

Duff & Phelps' *2017 SBBI Yearbook* estimates the historical arithmetic average inflation-adjusted market return over the period 1926 to 2016 as 8.9%.[30/] A current consensus analysts' inflation projection, as measured by the Consumer Price Index, is

---

[30/] *Duff & Phelps*, *2017 SBBI Yearbook* at 6-18.

2.4%.[31/] Using these estimates, the expected market return is approximately 11.50%.[32/] The market risk premium then is the difference between the 11.50% expected market return and my 3.70% risk-free rate estimate, or approximately 7.80%.

My historical estimate of the market risk premium was also calculated by using data provided by Duff & Phelps in its *2017 SBBI Yearbook*. Over the period 1926 through 2016, the Duff & Phelps study estimated that the arithmetic average of the achieved total return on the S&P 500 was 12.0%[33/] and the total return on long-term Treasury bonds was 6.00%.[34/] The indicated market risk premium is 6.0% (12.0% - 6.0% = 6.0%).

Q. HOW DOES YOUR ESTIMATED MARKET RISK PREMIUM RANGE COMPARE TO THAT ESTIMATED BY DUFF & PHELPS?

A. The Duff & Phelps analysis indicates a market risk premium falls somewhere in the range of 5.5% to 6.9%. My market risk premium falls in the range of 6.0% to 7.8%. My average market risk premium of approximately 6.9% is at the high-end of the Duff & Phelps range.

Q. HOW DOES DUFF & PHELPS MEASURE A MARKET RISK PREMIUM?

A. Duff & Phelps makes several estimates of a forward-looking market risk premium based on actual achieved data from the historical period of 1926 through 2016 as well as normalized data. Using this data, Duff & Phelps estimates a market risk premium derived from the total return on large company stocks (S&P 500), less the income return on Treasury bonds. The total return includes capital appreciation, dividend or coupon reinvestment returns, and annual yields received from coupons and/or dividend payments.

31/ *Blue Chip Financial Forecasts*, June 1, 2017 at 2.

32/ $\{ [(1 + 0.089) * (1 + 0.024)] – 1 \} * 100$.

33/ *Duff & Phelps, 2017 SBBI Yearbook* at 6-17.

34/ *Id.*

The income return, in contrast, only reflects the income return received from dividend payments or coupon yields. Duff & Phelps claims the income return is the only true risk-free rate associated with Treasury bonds and is the best approximation of a truly risk-free rate.[35/] I disagree with this assessment from Duff & Phelps because it does not reflect a true investment option available to the marketplace and therefore does not produce a legitimate estimate of the expected premium of investing in the stock market versus that of Treasury bonds. Nevertheless, I will use Duff & Phelps' conclusion to show the reasonableness of my market risk premium estimates.

Duff & Phelps' range is based on several methodologies. First, Duff & Phelps estimates a market risk premium of 6.9% based on the difference between the total market return on common stocks (S&P 500) less the income return on Treasury bond investments over the 1926-2016 period.

Second, Duff & Phelps updated the Ibbotson & Chen supply-side model, which found that the 6.9% market risk premium based on the S&P 500 was influenced by an abnormal expansion of price-to-earnings ("P/E") ratios relative to earnings and dividend growth during the period, primarily over the last 30 years. Duff & Phelps believes this abnormal P/E expansion is not sustainable.[36/] Therefore, Duff & Phelps adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings. Based on this alternative methodology, Duff & Phelps published a long-horizon supply-side market risk premium of 5.97%.[37/]

35/ *Duff & Phelps, 2017 Valuation Handbook* at 3-32.
36/ *Id.* at 3-36.
37/ *Id.*

Finally, Duff & Phelps develops its own recommended equity, or market, risk premium by employing an analysis that takes into consideration a wide range of economic information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 3.5%, Duff & Phelps concludes the current expected, or forward-looking, market risk premium is 5.5%, implying an expected return on the market of 9.0%.[38]

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. As shown in Exhibit ICNU/219 using the equation on page 41 above, based on my low market risk premium of 6.0% and my high market risk premium of 7.8%, a risk-free rate of 3.7%, and a beta of 0.70, my CAPM analysis produces a return of 7.92% to 9.19%. Based on my assessment of risk premiums in the current market, as discussed above, I recommend the high-end CAPM return estimate because it closely aligns the market risk premium with the prevailing risk-free rate. I recommend a CAPM return of 9.19%, rounded to 9.20%.

II.M. Return on Equity Summary

Q. BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR PGE?

A. Based on my analyses, I estimate PGE's current market cost of equity to be 9.25%.

---

[38] *Id.* at 3-48.

TABLE 8

Return on Common Equity Summary

Description	Results
DCF	8.90%
Risk Premium	9.60%
CAPM	9.20%

My recommended return on common equity of 9.25% is at the midpoint of my estimated range of 8.90% to 9.60%. As shown in Table 8 above, the high-end of my estimated range is based on my risk premium studies. The low-end is based on my DCF return. My CAPM result is at the approximate midpoint of my recommended range.

My return on equity estimates reflect observable market evidence, the impact of Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, and a general assessment of the current investment risk characteristics of the electric utility industry, and the market's demand for utility securities.

II.N. Financial Integrity

Q. WILL YOUR RECOMMENDED OVERALL RATE OF RETURN SUPPORT AN INVESTMENT GRADE BOND RATING FOR PGE?

A. Yes. I have reached this conclusion by comparing the key credit rating financial ratios for PGE at my proposed return on equity and the Company's actual test-year-end capital structure to S&P's benchmark financial ratios using S&P's new credit metric ranges.

Q. PLEASE DESCRIBE THE MOST RECENT S&P FINANCIAL RATIO CREDIT METRIC METHODOLOGY.

A. S&P publishes a matrix of financial ratios corresponding to its assessment of the business risk of utility companies and related bond ratings. On May 27, 2009, S&P expanded its matrix criteria by including additional business and financial risk categories.[39/]

Based on S&P's most recent credit matrix, the business risk profile categories are "Excellent," "Strong," "Satisfactory," "Fair," "Weak," and "Vulnerable." Most utilities have a business risk profile of "Excellent" or "Strong."

The financial risk profile categories are "Minimal," "Modest," "Intermediate," "Significant," "Aggressive," and "Highly Leveraged." Most of the utilities have a financial risk profile of "Aggressive." PGE has a "Strong" business risk profile and a "Significant" financial risk profile.

Q. PLEASE DESCRIBE S&P'S USE OF THE FINANCIAL BENCHMARK RATIOS IN ITS CREDIT RATING REVIEW.

A. S&P evaluates a utility's credit rating based on an assessment of its financial and business risks. A combination of financial and business risks equates to the overall assessment of PGE's total credit risk exposure. On November 19, 2013, S&P updated its methodology. In its update, S&P published a matrix of financial ratios that defines the level of financial risk as a function of the level of business risk.

S&P publishes ranges for primary financial ratios that it uses as guidance in its credit review for utility companies. The two core financial ratio benchmarks it relies on in its credit rating process include: (1) Debt to Earnings Before Interest, Taxes,

---

39/ S&P updated its 2008 credit metric guidelines in 2009, and incorporated utility metric benchmarks with the general corporate rating metrics. *Standard & Poor's RatingsDirect*: "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009.

Depreciation and Amortization ("EBITDA"); and (2) Funds From Operations ("FFO") to Total Debt.[40]

Q. HOW DID YOU APPLY S&P'S FINANCIAL RATIOS TO TEST THE REASONABLENESS OF YOUR RATE OF RETURN RECOMMENDATIONS?

A. I calculated each of S&P's financial ratios based on PGE's cost of service for its retail jurisdictional operations. While S&P would normally look at total consolidated PGE financial ratios in its credit review process, my investigation in this proceeding is not the same as S&P's. I am attempting to judge the reasonableness of my proposed cost of capital for rate-setting in PGE's retail regulated utility operations. Hence, I am attempting to determine whether my proposed rate of return will in turn support cash flow metrics, balance sheet strength, and earnings that will support an investment grade bond rating and PGE's financial integrity.

Q. DID YOU INCLUDE ANY OFF-BALANCE SHEET DEBT EQUIVALENTS?

A. Yes, I did. The off-balance sheet debt associated with purchase power agreements and operating leases, and their associated amortization and interest expense were obtained from the S&P Capital IQ website, as shown on my Exhibit ICNU/220, Gorman/3.

Q. PLEASE DESCRIBE THE RESULTS OF THIS CREDIT METRIC ANALYSIS AS IT RELATES TO PGE.

A. The S&P financial metric calculations for PGE at a 9.25% return are developed on Exhibit ICNU/220, Gorman/1. The credit metrics produced below, with PGE's financial risk profile from S&P of "Significant" and business risk score by S&P of "Strong," will be used to assess the strength of the credit metrics based on PGE's retail operations in the state of Oregon.

[40] *Standard & Poor's RatingsDirect*: "Criteria: Corporate Methodology," November 19, 2013.

PGE's adjusted total debt ratio is approximately 55.0% using the Company's projected capital structure. As shown on Exhibit ICNU/220, Gorman/4, this adjusted debt ratio is within the range of S&P ratios for BBB-rated utilities. Hence, I concluded this capital structure reasonably supports PGE's current investment grade bond rating.

Based on an equity return of 9.25%, PGE will be provided an opportunity to produce a debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") ratio of 2.8x. This is within S&P's "Intermediate" guideline range of 2.5x to 3.5x."[41/] This ratio supports an investment grade credit rating.

PGE's retail operations FFO to total debt coverage at a 9.25% equity return is 25%, which is within S&P's "Intermediate" metric guideline range of 23% to 35%. This FFO/total debt ratio will support an investment grade bond rating.

At my recommended return on equity of 9.25%, the Company's projected capital structure, and the Company's embedded debt cost, PGE's financial credit metrics continue to support credit metrics at an investment grade utility level.

III. RESPONSE TO PGE WITNESS DR. BENTE VILLADSEN

Q. WHAT RETURN ON COMMON EQUITY IS PGE PROPOSING IN THIS PROCEEDING?

A. PGE's proposed return on equity is supported by its witness Dr. Bente Villadsen. She recommends a return on equity for PGE in the range of 9.30% to 10.30%, with a midpoint of 9.80% (Exhibit PGE/1100, Villadsen/1-2). The Company is requesting 9.75% in this case.

41/ *Id.*

Q. PLEASE DESCRIBE DR. VILLADSEN'S METHODOLOGY SUPPORTING HER RETURN ON COMMON EQUITY.

A. Dr. Villadsen arrived at her estimate using several models: a simple DCF, a multi-stage growth DCF, and a risk premium model using a regression formula derived from allowed returns on equity and long-term Treasury yields. Dr. Villadsen checks her results with a traditional CAPM and an empirical CAPM ("ECAPM"). These models were applied to a group of 25 integrated electric utility companies, which Dr. Villadsen found had risk comparable to PGE. (Exhibit PGE/1100, Villadsen/2-3).

Q. IS DR. VILLADSEN'S ESTIMATED RETURN ON EQUITY FOR PGE REASONABLE?

A. No. Dr. Villadsen's recommended return on equity of 9.80% (and the Company's requested 9.75%) for PGE are excessive and unreasonable for a low-risk regulated electric utility company. Further, Dr. Villadsen asserts that considering PGE's significantly smaller size relative to the proxy group, a size premium of 60-70 basis points or a return in the upper end of her range is appropriate. (Exhibit PGE/1100, Villadsen/11-12). The unreasonableness of Dr. Villadsen's recommendation is evident from a detailed assessment of the rate of return models supporting her recommendation in this proceeding.

Q. PLEASE SUMMARIZE DR. VILLADSEN'S RETURN ON EQUITY STUDY RESULTS.

A. Dr. Villadsen's return on equity study results are summarized in Table 9 below.

TABLE 9

Summary of Dr. Villadsen's Results

	Dr. Villadsen's Results			
Model	**Model Results**	**ATWACC Adder**	**Recommended ROE**	**Adjusted ROE**
	(1)	**(2)**	**(3)**	**(4)**
DCF				
Simple (1/4 Growth)	8.9%	1.4%	10.3%	8.9%
Multi-Stage (Blue Chip)	7.9%	1.1%	9.0%	7.9%
Multi-Stage (Blue Chip and OMB)	8.0%	1.1%	9.1%	8.0%
CAPM				
Traditional CAPM	8.7% - 8.9%	0.7% - 0.9%	9.4% - 9.7%	8.7% - 8.9%
ECAPM (1.5%)	9.1% - 9.3%	0.8% - 0.9%	9.9% -10.2%	9.2% - 9.3%
Traditional CAPM (Hamada)			9.2% - 9.9%	Reject
ECAPM (1.5%) (Hamada)			9.8% -10.1%	Reject
Risk Premium				
Regression (Normalized)			10.4%	9.8%
Regression			9.9%	9.5%
Range			9.3% - 10.3%	8.9% - 9.8%
Requested ROE			9.75%	

ROE = Return on Equity

ATWACC = After-Tax Weighted Average Cost of Capital

As shown in Table 9 above, the model return on equity results of Dr. Villadsen's studies applied to her proxy group indicate that PGE's current market return on equity is in the range of 8.0% to 9.3% based on her DCF and CAPM studies, and 9.9% to 10.4% based on her risk premium studies.

She then increases her market return on equity estimate by adding a return on equity adder in the range of 0.7% to 1.4% using an After-Tax Weighted Average Cost of Capital ("ATWACC") adder methodology. This ATWACC adder increases her recommended range up to 9.3% to 10.3%. Dr. Villadsen asserts this ATWACC return on equity adder is necessary to properly recognize PGE's financial risk when applying a market return on equity to its book value common equity. (Exhibit PGE/1100, Villadsen/9)

Q. DO DR. VILLADSEN'S RETURN ON EQUITY MODEL RESULTS SUPPORT THE COMPANY'S REQUESTED 9.75% RETURN ON EQUITY?

A. No. As described below and as shown in Table 9 above under Column 4, Dr. Villadsen's own studies, adjusted to remove her flawed ATWACC return on equity adder and incorporate reasonable adjustments, support a return on equity in the range of 8.9% to 9.8%. These adjusted results are comparable to my recommended return on equity range for PGE in this proceeding.

Q. PLEASE DESCRIBE THE ISSUES YOU HAVE WITH DR. VILLADSEN'S ANALYSES.

A. The issues and concerns I have with Dr. Villadsen's analyses in support of the Company's requested return on equity include the following:

1. She includes an ATWACC adjustment to her DCF return estimate.
2. For her CAPM analysis she includes both an ATWACC, and alternatively a leveraged beta adjustment to the results of her CAPM analysis.
3. She also relies on an empirical CAPM analysis and includes adders for ATWACC and leveraged beta adjustments. In addition to my concerns for these two adders, Dr. Villadsen's ECAPM analysis is miscalculated because she uses adjusted betas within an ECAPM format. This is inappropriate because an adjusted beta accomplishes the same thing as an ECAPM analysis. Both levelize the security market line in measuring a fair return on equity based on a given level of systematic risk or beta risk. Her ECAPM analysis double counts the increase in the CAPM return estimates for companies with betas less than 1, which reflects her proxy group and PGE in this case.
4. I take issue with her risk premium analysis because it is based only on a simple inverse relationship between equity risk premiums and interest rates. Equity risk premiums should be measured based on the current market's assessment of investment risk of equity versus debt securities. While interest rate changes are one

factor in assessing this risk differential, they are not the only factor. Dr. Villadsen's model is simply misspecified and is unreliable.

III.A. ATWACC

Q. PLEASE DESCRIBE DR. VILLADSEN'S PROPOSED ATWACC RETURN ON EQUITY ADDER.

A. Dr. Villadsen uses the ATWACC to increase the estimated market return on equity based on her DCF and CAPM analyses, to a higher return on equity that can be applied to PGE's book value common equity. She does this by calculating the ATWACC using the market return on equity estimate (DCF and CAPM estimates) and market weighted capital structures for each proxy company. She then uses this market ATWACC and each company's book value capital structures to derive a return on equity that produces the same ATWACC on the proxy group's book capital structure that was produced on its market value capital structure.

These ATWACC adjustments to her return on equity estimates are discussed on pages 8-10 of her direct testimony and developed in the workpapers accompanying her exhibits for the DCF and CAPM return estimates.

Q. WHY DOES DR. VILLADSEN BELIEVE THE ATWACC ADJUSTMENT TO HER DCF AND CAPM RETURN ESTIMATES IS REASONABLE?

A. Dr. Villadsen suggests that the sample firms' financial risk is different based on the market value of common equity than is the financial risk based on the book value of common equity. Therefore, Dr. Villadsen proposes to upwardly adjust her DCF and CAPM model results for the difference in financial risk based on the proxy companies' market value of common equity, compared to its book value common equity. (Exhibit PGE/1100, Villadsen/9)

She is in effect suggesting that firms have a different level of financial risk, depending on whether one is observing their market value capital structure or the book value capital structure.

Q. IS THE ATWACC ADJUSTMENT TO THE BASE RETURN ON EQUITY REASONABLE?

A. No. This is flawed for several reasons. First, the Company only has one level of financial risk, not two. Investors do not assess a different amount of financial risk for market and book common equity valuation. Rather, financial risk is a singular risk factor which describes its financial capital structure, cash flow strength to support financial obligations, and default provisions in its financial obligations.

Dr. Villadsen's belief that there are two levels of financial risk is simply not supported. Indeed, it is contradicted by data used by independent market participants to assess investment risk and security valuation. For example, S&P and *Value Line* provide general assessments of the financial and operating (or total investment) risks to the market investors. S&P does this in terms of rating the credit quality of the utility, based on the utility's ability to produce cash flows adequate to meet its book value financial obligations. S&P assesses a company's risk of failing to meet its financial obligations and is a direct assessment of a company's financial risk.

Value Line provides information to the market participants to help them assess the total investment risk including both financial risk and business risk for the utilities and other stock investments. The data *Value Line* provides to investors concerning these investment risk characteristics relates to book value factors including book value capital structure, book value cash flows, and book value earnings. All these book value factors are then used by investors to assess investment risk which allows them to derive market value stock prices. The book value parameters are an integral part of assessing risk and allowing investors to produce market valuations.

There is not a difference in financial risk for a company if you are examining its book value financial risk or market value financial risk. Rather, the book value and market value financial risks for the same company are interconnected to one another, and produce a single level of financial risk for the company.

Q. DO YOU BELIEVE THAT THE ATWACC METHODOLOGY IS REASONABLE POLICY FOR SETTING AN APPROVED RETURN ON EQUITY?

A. No. The ATWACC methodology is poor regulatory policy and should be rejected for several reasons.

1. First, it does not produce clear and transparent objectives for management to use that will accomplish the objective of minimizing its overall rate of return while preserving its financial integrity. Therefore, a regulatory commission cannot oversee the reasonableness and prudence of management decisions in managing its capital structure. Under the ATWACC theory, management's decisions to manage its capital structure can be skewed by changes in market value which change the market value capitalization mix. Management simply has no control over the market value capital structure, but it does have control over the book value capital structure. As such, setting the rate of return and measuring risk based on book value capital structure creates a more transparent and clear path for regulatory oversight of management's effort to maintain a balanced and reasonable capital structure.

2. Second, the ATWACC introduces significant additional instability into the utility's cost of service and tariff rates. Book value capital structure weights permit the utility to hedge or lock-in a large portion of capital market costs in arriving at the rate of return used to set rates. This rate of return cost hedge stabilizes the utility's cost of service, which in turn helps stabilize utility rates. A stable method of setting rates also allows investors to more accurately assess the future earnings and cash flow outlooks for the utility, which will reduce the business risk of the utility. The ATWACC, on the other hand, will produce an overall rate of return which will change based on both changes to market value capital structure weights and also based on changes to market capital costs. Hence, a major component of the cost structure of the utility (i.e., the overall rate of return) will vary based on market forces from rate case to rate case. This rate of return variability will introduce significant instability in the utility's cost of service (via rate of return changes) and hence instability in tariff rates. Introducing additional instability in the utility's cost structure and rates will not benefit either investors or ratepayers.

3. The ATWACC unnecessarily increases rates to produce an excessive return on equity opportunity for utility investors. Inflating utility's rates to provide this excessive earnings opportunity is unjust and unreasonable and should be rejected.

Q. HAS THE ATWACC METHODOLOGY PROPOSED BY DR. VILLADSEN BEEN ACCEPTED IN RATE-SETTING PROCEEDINGS IN THE UNITED STATES?

A. No. The ATWACC methodology has been consistently rejected in state jurisdictions throughout the country. The ATWACC methodology has been rejected by regulators for many reasons:

1. Designed to produce a higher return and no confidence in evidence supporting the ATWACC. (California Public Utilities Commission, Docket No. A.08-05-002, California-American Water Company, May 2009).

2. Method that inflates the rate of return by overstating the Company's financial risk and inflating rates to overcompensate utility investors. The Company simply provided inadequate justification for departing from the traditional method of estimating the rate of return. (Arizona Corporation Commission, Arizona-American Water Company, Docket No. W-01303A-05-0405, July 2006).

3. Is an unproven and never used methodology that is not reliable for setting rates. (Ohio Public Utilities Commission, Cause Nos. 07-551-EL-AIR *et al.*, Ohio Edison Company *et al.*, January 2009).

4. The Commission was not persuaded that the ATWACC methodology was appropriate for setting rates and declined to use it in the rate proceeding. (Public Service Commission of Wisconsin, Wisconsin Electric Power Company, 5-UR-103).

III.B. Dr. Villadsen's DCF Analyses

Q. PLEASE DESCRIBE DR. VILLADSEN'S DCF ANALYSIS.

A. Dr. Villadsen developed a constant growth DCF model based on a combined growth rate from IBES consensus analysts' and *Value Line* growth rate projections. Dr. Villadsen's DCF model results fall in the range 7.9% and 8.9%, with the higher estimate produced by her simple constant growth DCF model. She applied an ATWACC adder to the DCF model results and increased the DCF range to 9.0% to 10.3%. (Exhibit PGE/1100, Villadsen/35)

Q. PLEASE DESCRIBE THE ISSUES YOU HAVE WITH DR. VILLADSEN'S DCF ANALYSIS.

A. I have two issues with Dr. Villadsen's DCF analysis. First, as I discussed above the use of the ATWACC methodology is inappropriate and should be rejected. Second, similar to my DCF models, Dr. Villadsen's DCF studies are based on an average growth rate estimate of approximately 5.3%, which exceeds the long-term sustainable growth rate of 4.2%[42] as published by the consensus economists, which was used by both Dr. Villadsen and myself. Hence, her constant growth DCF result of 8.9%, excluding the ATWACC adder, can be used as a reasonable high-end DCF return estimate.

III.C. Dr. Villadsen's Risk Premium Analyses

Q. PLEASE DESCRIBE DR. VILLADSEN'S RISK PREMIUM ANALYSES.

A. As shown on her Exhibit PGE/1102, Dr. Villadsen measured the relationship of authorized returns on equity to long-term Treasury yields between 1990 and the third quarter of 2016 through a regression analysis. (Exhibit PGE/1100, Villadsen/37). She then uses the resulting regression formula to predict a risk premium based on a forecasted long-term Treasury yield of 3.89% from October 2016.[43] This regression formula and her forecasted Treasury yield of 3.89% produced an estimated risk premium of 6.54%. Dr. Villadsen then added her estimated risk premium of 6.54% to the forecasted Treasury yields of 3.34% and 3.89% (including utility yield spread adjustment of 55 basis points)

42/ *Blue Chip Financial Forecasts*, June 1, 2017, at 14.
43/ Exhibit PGE/1100, Villadsen/37.

to produce a cost of equity estimate in the range of 9.9% to 10.4%, with a midpoint of 10.15%.

She also concludes that this estimate does not require adjustment because the regulatory capital structures contain an equity component generally in the range of 48% to 52%, which is consistent with PGE's requested common equity of 50%. (Exhibit PGE/1100, Villadsen/38)

Q. DO YOU HAVE ANY ISSUES WITH DR. VILLADSEN'S RISK PREMIUM ANALYSIS?

A. Yes. Dr. Villadsen's regression model reflects a simplistic, linear relationship between equity risk premiums and interest rates. This overly simplistic relationship is not based on basic risk and return valuation principles. While academic studies have shown that there has been a positive and negative linear relationship between these variables in the past, these studies have found that the relationship changes over time and is influenced by changes in perception of the investment risk of bond investments relative to equity investments, rather than only changes to nominal interest rates.[44/]

In the 1980s, equity risk premiums were inversely related to interest rates, but that was likely attributable to the interest rate volatility that existed at that time. When interest rates were more volatile, the relative perception of bond investment risk increased relative to the investment risk of equities. This changing investment risk perception caused changes in equity risk premiums.

44/ "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001; "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985.

In today's marketplace, interest rate volatility is not as extreme as it was during the 1980s.[45/] Nevertheless, changes in the perceived risk of bond investments relative to equity investments still drive changes in equity premiums. However, a relative investment risk differential cannot be measured simply by observing nominal interest rates. Changes in nominal interest rates are highly influenced by changes to inflation outlooks, which also change equity return expectations. As such, the relevant factor needed to explain changes in equity risk premiums is the relative changes to the risk of equity versus debt securities investments, and not simply changes in interest rates.

Importantly, Dr. Villadsen's analysis simply ignores investment risk differentials. She bases her adjustment to the equity risk premium exclusively on changes in nominal interest rates. This is a flawed methodology and does not produce accurate or reliable risk premium estimates. As such, her argument should be rejected by the Commission.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH DR. VILLADSEN'S RISK PREMIUM STUDY?

A. Yes. She uses a forecasted Treasury bond yield of 3.89%, which is based on a *Blue Chip Economic Indicator* from October 2016 of 2.8% including adjustments for term to maturity of 0.54%, and outlooks for changes in yield spreads between Treasuries and corporate bonds of 0.55 basis points. Dr. Villadsen's Treasury yield projections overstate independent market participants' projected outlooks for future interest rates around the time she performed her study. In the *Blue Chip Financial Forecasts* dated October 2016, the 30-year Treasury bond projected yield two years out was 3.1%,[46] which is considerably lower than Dr. Villadsen's projected yield of 3.89%.

45/ Morningstar SBBI, 2009 Classic Yearbook at 95-96.

46/ *Blue Chip Financial Forecasts*, October 1, 2016 at 2.

Dr. Villadsen's 3.89% risk-free rate simply does not reflect independent market economists' outlooks for future interest rates and cannot be used to accurately measure the correct market return on equity for PGE.

Q. CAN DR. VILLADSEN'S RISK PREMIUM STUDY BE MODIFIED TO PRODUCE A REASONABLE RETURN FOR PGE?

A. Yes. Disregarding Dr. Villadsen's simplistic inverse relationship and using a projected Treasury yield published by independent economists, of 3.7%, and adding this 3.7% Treasury yield to an equity risk premium of 6.1% produces a risk premium return on equity for PGE of 9.8%.

III.D. Dr. Villadsen's CAPM Analysis

Q. PLEASE DESCRIBE DR. VILLADSEN'S CAPM ANALYSIS.

A. Dr. Villadsen explains that she only uses the CAPM analyses to corroborate her recommended range and the Company's proposed return on equity. Dr. Villadsen develops two versions of the CAPM model, a traditional CAPM and an Empirical CAPM ("ECAPM).[47/]

In her analyses, Dr. Villadsen relied upon two different scenarios. In the first scenario, she used a projected risk-free rate of 3.89% with a market risk premium of 6.9%. In this scenario, Dr. Villadsen increased the risk-free rate by approximately 55 basis points to account for higher interest rates that will align with lower market risk premiums. In the second scenario, she used a risk-free rate of 3.34% with a market risk premium of 7.9%.[48/]

[47/] Exhibit PGE/1103.
[48/] *Id*. at 4.

As shown in Table 10 below, based on her two scenarios, Dr. Villadsen produced a traditional CAPM before any adders in the range of 8.7% to 8.9% (Column 1). Similarly, applying the ECAPM before any adders, she produces a return estimate in the range of 9.2% to 9.3% (Column 1).

TABLE 10

Dr. Villadsen's CAPM Results

			Adjusted			Adders		
Line	**Description**	**Base**	**ATWACC ROE**	**Hamada**	**Tax Hamada**	**ATWACC ROE**	**Hamada**	**Tax Hamada**
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Traditional CAPM							
1	Scenario 1	8.7%[1]	9.6%[3]	9.6%[4]	9.3%[4]	0.90%	0.90%	0.60%
2	Scenario 2	8.9%[2]	9.7%[3]	9.9%[5]	9.6%[5]	0.80%	1.00%	0.70%
	Empirical CAPM							
3	Scenario 1	9.2%[1]	10.1%[3]	9.9%[4]	9.6%[4]	0.90%	0.70%	0.40%
4	Scenario 2	9.3%[2]	10.2%[3]	10.1%[5]	9.9%[5]	0.90%	0.80%	0.60%

Sources:
[1]Exhibit PGE / 1104 / Villadsen / 3.
[2]Exhibit PGE / 1104 / Villadsen / 4.
[3]Exhibit PGE / 1104 / Villadsen / 7.
[4]Exhibit PGE / 1104 / Villadsen / 10.
[5]Exhibit PGE / 1104 / Villadsen / 11.

To this barebones or "base" CAPM return, Dr. Villadsen proposes either one of two return on equity adders. First, she proposes to add to her base CAPM return estimate an ATWACC return on equity adder in the range of 80 to 90 basis points. For the reasons outlined above, this ATWACC adder should be rejected as unreliable and an imbalanced return on equity component. Alternatively, Dr. Villadsen proposes a return on equity adder to reflect a leveraged beta adjustment. This leveraged beta adjustment adds 90 to 100 basis points to the base CAPM return.

Dr. Villadsen's leverage adjustment, however, is unreliable and flawed and should be rejected. This leverage adjustment return on equity adder to the base CAPM return estimate produces an excessive and unreasonable return on equity for PGE.

Q. PLEASE EXPLAIN DR. VILLADSEN'S LEVERAGED BETA ADJUSTMENT.

A. As an alternative to her ATWACC adder to her CAPM results, Dr. Villadsen also measures an additional return on equity adder based on leveraged adjustments to the beta component of the CAPM study. In producing this adder, she applies the Hamada method for de-levering and re-levering the beta component in both the CAPM and the ECAPM with and without the effect of income taxes. This Hamada beta leveraging adjustment is described by Dr. Villadsen at pages 8-11 of her Exhibit PGE/1103.

This methodology produces very similar results to Dr. Villadsen's return on equity adder using the ATWACC methodology. Applying the Hamada formula increases the *Value Line* beta from 0.70 to 0.83 (without taxes) and 0.79 (with taxes).[49/] The Hamada model produces CAPM results in the range of 9.2% to 9.9% and ECAPM results in the range of 9.5% to 10.1%.[50/]

Q. IS DR. VILLADSEN'S APPLICATION OF THE LEVERAGED BETA RETURN ON EQUITY ADDER REASONABLE?

A. No. Dr. Villadsen's proposal to de-lever and then re-lever the beta suggests that utilities' financial risk can be measured only by changes in common equity weights of capital structure, and that financial risk is the only relevant systematic risk reflected in beta. Neither of these assumptions are accurate. First, a utility company's financial risk is a component of capital structure mix, but also can be impacted by its embedded cost of debt, debt maturity and other liquidity factors. For example, a utility that has lower cost

49/ *Id.* at 8-9.
50/ *Id*. at 10-12.

debt and a higher debt percentage of total capital, may have lower financial risk than a utility with a lower debt ratio if its cash flow coverages of interest and total debt are stronger than the latter company. Dr. Villadsen's analysis is not based on a complete assessment of financial risk. Other factors affecting financial risk also relate to cash flow generation relative to financial obligation, and financial instruments' terms and conditions as well as regulatory terms and conditions that support the generation of cash for the utility. All of this is set aside in Dr. Villadsen's financial risk adjustment to beta based on leverage risk alone.

Also, financial risk is not the only systematic risk that should be considered in adjusting beta. Systematic risk can include many factors that were not properly considered by Dr. Villadsen. Applying the Hamada methodology is just another way of increasing the CAPM results. Therefore, Dr. Villadsen's results based on this approach should be completely disregarded by the Commission because they serve only one purpose, to inflate revenue requirements for PGE's ratepayers.

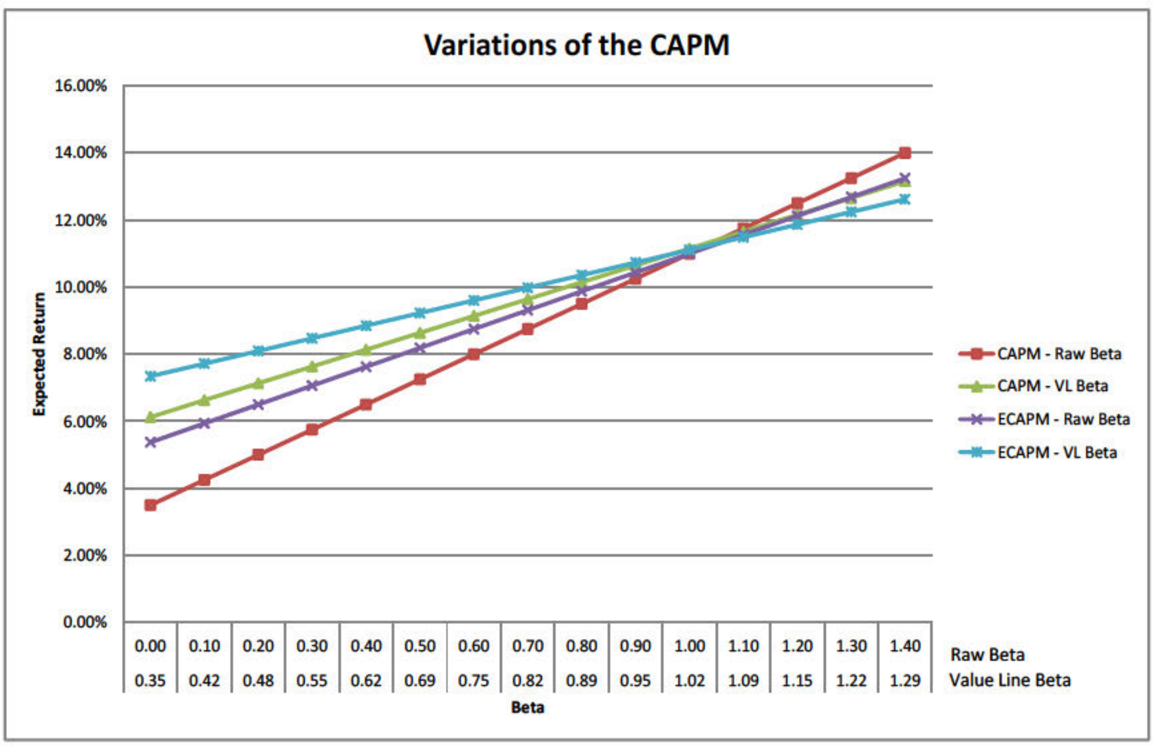
Q. DO YOU HAVE ANY OTHER CONCERNS WITH DR. VILLADSEN'S CAPM RETURN ESTIMATES?

A. Yes. I also have concerns with Dr. Villadsen's development of an ECAPM return estimate. Specifically, Dr. Villadsen included an adjusted beta within her ECAPM study. I believe this is inconsistent with the academic research supporting the development of an ECAPM methodology.[51/] Bottom line, using adjusted betas within an ECAPM study double counts the purpose of the ECAPM study – that is, to flatten the security market line and increase a CAPM return estimate for companies with betas less than 1, and

51/ See Black, Fischer, "Beta and Return," *The Journal of Portfolio Management*, Fall 1993, 8-18; and Black, Fischer, Michael C. Jensen and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," 1972.

decrease the CAPM return estimate for betas greater than 1. Dr. Villadsen goes over the objective of the ECAPM at pages 7 and 8 of her Exhibit PGE/1103. As shown in Dr. Villadsen's Figure 3-1, the ECAPM will raise the intercept point of the security market line and flatten the slope. Again, this has the effect of increasing CAPM return estimates for companies with betas less than 1, and decreasing the CAPM return estimates for companies with betas greater than 1. Importantly, however, the use of an adjusted beta such as those published by *Value Line*, produces comparable adjustments to the security market line and CAPM return estimate. In effect, using an adjusted beta within an ECAPM study has the effect of a double adjustment to the slope and intercept of the security market line. This is illustrated in my Figure 5 below.

Figure 5



Assumptions:
Market Risk Premium is 7.50%
Risk-Free Rate is 3.50%

As shown in Figure 5 above, the CAPM using a *Value Line* beta, versus a CAPM using a raw beta shows that the *Value Line* beta raises the intercept slope and flattens the security market line. Further, the ECAPM using a raw beta, and an ECAPM using a *Value Line* beta, have a magnified effect of increasing the intercept slope and further flattening the security market line.

There is simply no legitimate basis to use an adjusted beta within an ECAPM because they are designed to produce the same effect on the CAPM return estimate.

Q. IS THERE ANY ACADEMIC SUPPORT FOR DR. VILLADSEN'S PROPOSED USE OF AN ADJUSTED BETA IN AN ECAPM STUDY?

A. No. I am unaware of any peer reviewed academic study showing that the ECAPM is more accurate using adjusted betas. To my knowledge, the ECAPM has been tested and published with raw beta estimates. Further, Dr. Villadsen has not provided any academic research that was subjected to academic peer review which supports her proposed use of an adjusted beta in an ECAPM study. As such, the practice of using an adjusted beta in an ECAPM study is simply not supported by academic research. While I have encountered the ECAPM analysis in many proceedings over the last 10 years, I have failed to find any utility witness in support of this methodology that can provide academic support for use of an ECAPM analysis with an adjusted beta such as a *Value Line* published beta. Rather, the ECAPM is designed to accommodate an unadjusted beta. Support for this academic study is identified above. For the reasons outlined above, Dr. Villadsen's proposal to use adjusted betas in an ECAPM study should be rejected.

Q. IS THERE A WAY TO MORE ACCURATELY MEASURE THE COST OF EQUITY FOR PGE USING THE ECAPM?

A. Because the makeup of the ECAPM model is based on a raw or regression beta, if the appropriate beta is used in the ECAPM it would produce a reasonable return estimate. As such, if the adjusted *Value Line* betas are modified to remove *Value Line*'s adjustment to the regression beta for the long-term tendency to converge on the market beta of 1, the *Value Line* unadjusted beta can be properly used in the ECAPM study.

Removing the beta adjustment to reflect a raw beta for an ECAPM will generally produce a more accurate ECAPM result. For example, on Dr. Villadsen's Exhibit PGE/1104, page 4, she produces an average CAPM cost for her proxy group of 8.9%, and an ECAPM return of 9.3%. The average proxy group adjusted *Value Line* beta to produce an 8.9% CAPM return is approximately 0.70. This would equate to an unadjusted/raw beta estimate of 0.52.[52/] Using a raw beta of 0.52 and Dr. Villadsen's ECAPM methodology produces an ECAPM estimate of 8.20%.[53/]

Q. DID DR. VILLADSEN ALSO OFFER AN ASSESSMENT OF CURRENT MARKET CONDITIONS IN SUPPORT OF HER RECOMMENDED RETURN ON EQUITY?

A. Yes. Dr. Villadsen suggests a few factors that gauge investor sentiment, including interest rates, market volatility, measured by the CBOE Volatility Index, known as the VIX and the changing P/E ratios.[54/] She concludes that low interest rates resulted in high utility spreads and that market volatility in 2016 has been elevated relative to the volatility observed in the past.

52/ (Adj. Beta - 0.35)/0.67 = Raw Bea. (0.70 – 0.35)/0.67 = 0.52.

53/ ECAPM (Raw Beta) = RF + 0.19 x MRP + 0.81 x MRP x Raw Beta.
ECAPM (0.52) = 3.34% + 0.19 x 7.9% + 0.81 x 7.9% x 0.52 = 8.2%.

54/ Exhibit PGE/1100, Villadsen/13-25.

Q. DO YOU BELIEVE THAT DR. VILLADSEN'S USE OF THESE MARKET SENTIMENTS SUPPORTS HER FINDINGS THAT PGE'S MARKET COST OF EQUITY IS 9.75%?

A. No. In many instances Dr. Villadsen's analysis simply ignores market sentiments favorable toward utility companies and instead lumps utility investments in with higher-risk corporate investments. A fair analysis of utility securities shows the market generally regards utility securities as low-risk investment instruments and supports the finding that utilities' cost of capital is very low in today's marketplace.

Q. WHAT IS THE MARKET SENTIMENT FOR UTILITY INVESTMENTS?

A. The market sentiment toward utility investments, rather than just general corporate investments, is that the market is placing high value on utility securities recognizing their low risk and stable characteristics.

For example, this is illustrated by my Exhibit ICNU/216, under column 11 showing the spread between "A" rated utility bond yields and "Aaa" rated corporate bond yields. Currently, the spread is approximately 0.28%. This is a relatively low spread over the 37-year time horizon. Indeed, current spreads of utility versus high-grade corporate bond yields are at the lowest level they have been in most periods over the last 37 years. This is also reflective of the spreads between "Baa" utility bond yields relative to "Baa" corporate bond yields. Currently, utility bonds are trading at a premium to corporate bonds. This has been largely the case during the significant market turbulence that has occurred over the last five to eight years. However, over longer periods of time, utility bond yields on average trade at parity to a premium to corporate "Baa" rated bond yields. The current strong utility bond valuation is an indication of the market's sentiment that utility bonds have lower risk than general corporate bonds and are generally regarded as a safe haven by the investment industry.

Further, other measures of utility stock valuations also support a robust market for utility stocks. As shown on my Exhibit ICNU/203, utility valuation measures – *e.g.*, price-to-earnings ratio, market-to-book ratio, and market price to cash flow ratio – show stock valuation measures for the proxy groups are robust. For example, for the proxy group, the current price-to-earnings ratio is comparable to and the cash flow ratio is stronger than the 14-year average valuation metrics.

For all these reasons, direct assessments of valuation measures and market sentiment toward utility securities support the credit rating agencies' findings, as quoted above, that the utility industry is largely regarded as a low-risk, safe haven investment. All of this supports my finding that utilities' market cost of equity is very low in today's very low cost capital market environment.

Q. DO YOU HAVE ANY FURTHER COMMENTS IN REGARD TO DR. VILLADSEN'S INTEREST RATE PROJECTIONS?

A. Yes. First, it is simply not known how much, if any, long-term interest rates will increase from current levels or whether they have already fully accounted for the termination of the Federal Reserve's Quantitative Easing program and the increase in the Federal Funds rate. Nevertheless, I do agree that this Federal Reserve program introduced risk or uncertainty in long-term interest rate markets. Because of this uncertainty, caution should be taken in estimating PGE's current return on common equity in this case. However, as noted in the EEI quote above, the increase in short-term interest rates had no impact on longer-term yields that "remain at historically low levels and are influenced more by the level of inflation and economic strength than by the Fed's short-term rate policy."[55/]

[55/] *EEI Q4 2015 Financial Update*: "Stock Performance" at 6.

Second, I would note PGE is largely shielded from significant changes in capital market costs. To the extent interest rates ultimately increase above current levels, which may have an impact on required returns on common equity, at that point in time, PGE, like all other utilities, can file to change rates to restate its authorized rate of return at the prevailing market levels.

. Finally, while current observable interest rates are actual market data that provides a measure of the current cost of capital, the accuracy of forecasted interest rates is problematic at best.

Q. WHY DO YOU BELIEVE THAT THE ACCURACY OF FORECASTED INTEREST RATES IS HIGHLY PROBLEMATIC?

A. Over the last several years, observable current interest rates have been a more accurate predictor of future interest rates than economists' consensus projections. Exhibit ICNU/221 illustrates this point. On this exhibit, under Columns 1 and 2, I show the actual market yield at the time a projection is made for Treasury bond yields two years in the future. In Column 1, I show the actual Treasury yield. In Column 2, I show the projected yield two years out.

As shown in Columns 1 and 2, over the last several years, Treasury yields were projected to increase relative to the actual Treasury yields at the time of the projection. In Column 4, I show what the Treasury yield actually turned out to be two years after the forecast. In Column 5, I show the actual yield change at the time of the projections relative to the projected yield change.

As shown in this exhibit, economists consistently have been projecting that interest rates will increase over several years. However, as shown in Column 5, those yield projections have turned out to be overstated in almost every case. Indeed, actual

Treasury yields have decreased or remained flat over the last several years rather than increased as the economists' projections indicated. As such, current observable interest rates are just as likely, maybe more likely, to accurately predict future interest rates as are current economists' projections.

Q. DID DR. VILLADSEN CONSIDER ADDITIONAL BUSINESS RISKS TO JUSTIFY HER PROPOSED RETURN ON EQUITY?

A. Yes. Dr. Villadsen points out that PGE's large capital investment program and its smaller size, relative to the proxy group, will warrant a return on equity at the upper end of her range.[56] I disagree. Setting the return on equity as proposed by Dr. Villadsen's model results will place an unreasonable burden on the ratepayers and should be rejected. As discussed below, PGE's relative risk is comparable to the risk of the utility companies included in the proxy group.

Q. WHY DO YOU BELIEVE THAT PGE FACES RISKS THAT ARE COMPARABLE TO THE RISKS FACED BY PROXY GROUP COMPANIES?

A. As shown on my Exhibit ICNU/205, the average S&P credit rating for my proxy group of BBB+ is higher, albeit comparable to PGE's credit rating of BBB. On the other hand, the proxy group Moody's credit rating of Baa1 is lower than PGE's credit rating of A3. The relative risks discussed by Dr. Villadsen's testimony are already incorporated in the credit ratings of the proxy group companies. S&P and Moody's go through great detail in assessing a utility's business risk and financial risk in order to evaluate their assessment of its total investment risk. Therefore, this total risk investment assessment of PGE, in comparison to a proxy group, is fully absorbed into the market's perception of PGE's risk and the proxy group fully captures the investment risk of PGE.

[56] Exhibit PGE/1100, Villadsen/11-12.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/201

QUALIFICATIONS OF MICHAEL P. GORMAN

June 16, 2017

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Managing Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelors of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission ("ICC"). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the Staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. ("DBA"). In April 1995, the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating to industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals ("RFPs") for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have participated in rate cases on rate design and class cost of service for electric, natural gas, water and wastewater utilities. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements, and have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the Federal Energy Regulatory Commission and numerous state regulatory commissions including: Arkansas, Arizona, California, Colorado, Delaware, Florida, Georgia, Idaho, Illinois, Indiana, Iowa, Kansas, Louisiana, Michigan, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Tennessee, Texas, Utah, Vermont, Virginia, Washington, West Virginia, Wisconsin, Wyoming, and before the provincial regulatory boards in Alberta and Nova Scotia, Canada. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst ("CFA") from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of the CFA Institute's Financial Analyst Society.

\\Doc\Shares\ProlawDocs\SDW\10438\Exhibit\322206.docx

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/202

RATE OF RETURN

June 16, 2017

Portland General Electric Company

Rate of Return
(December 31, 2018)

Line	Description	Amount (1)	Weight (2)	Cost (3)	Weighted Cost (4)
1	Long-Term Debt	$ 2,661,400	51.35%	5.17%	2.65%
2	Common Equity	$ 2,521,922	48.65%	**9.25%**	4.50%
3	**Total**	**$ 5,183,322**	**100.00%**		**7.16%**

Source:
Hagger - Liddle / 2.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/203

VALUATION METRICS

June 16, 2017

Portland General Electric Company

Electric Utilities
(Valuation Metrics)

		Price to Earnings (P/E) Ratio [1]																
Line	Company	16-Year Average (1)	2017 [2] (2)	2016 (3)	2015 (4)	2014 (5)	2013 (6)	2012 (7)	2011 (8)	2010 (9)	2009 (10)	2008 (11)	2007 (12)	2006 (13)	2005 (14)	2004 (15)	2003 (16)	2002 (17)
1	ALLETE	17.16	19.70	18.63	15.06	17.23	18.59	15.88	14.66	15.98	16.08	13.95	14.78	16.55	17.91	25.21	N/A	N/A
2	Alliant Energy	15.76	20.00	22.30	18.07	16.60	15.28	14.50	14.45	12.47	13.86	13.43	15.08	16.82	12.59	14.00	12.69	19.93
3	Ameren Corp.	15.42	20.10	18.29	17.55	16.71	16.52	13.35	11.93	9.66	9.26	14.21	17.45	19.39	16.72	16.28	13.51	15.78
4	American Electric Power	13.68	16.70	15.16	15.77	15.88	14.49	13.77	11.92	13.42	10.03	13.06	16.27	12.91	13.70	12.42	10.66	12.68
5	Avangrid, Inc.	29.57	18.20	N/A	40.94	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	17.75	20.00	18.80	17.60	17.28	14.64	19.30	14.08	12.74	11.42	14.97	30.88	15.39	19.45	24.43	13.84	19.27
7	Black Hills	17.67	19.50	22.29	16.14	19.03	18.24	17.13	31.13	18.10	9.93	N/A	15.02	15.77	17.27	17.13	15.95	12.52
8	CenterPoint Energy	14.93	23.10	21.91	18.10	16.96	18.75	14.85	14.58	13.78	11.81	11.27	15.00	10.27	19.06	17.84	6.05	5.59
9	CMS Energy Corp.	16.77	22.40	20.94	18.29	17.30	16.32	15.07	13.62	12.46	13.56	10.87	26.84	22.18	12.60	12.39	N/A	N/A
10	Consol. Edison	15.11	17.90	18.80	15.59	15.90	14.72	15.39	15.08	13.30	12.55	12.29	13.78	15.49	15.13	18.21	14.30	13.28
11	Dominion Resources	18.00	21.40	21.33	22.14	22.97	19.25	18.91	17.27	14.35	12.74	13.78	20.63	15.98	24.89	15.07	15.24	12.05
12	DTE Energy	15.43	20.60	18.97	18.11	14.91	17.92	14.89	13.51	12.27	10.41	14.81	18.27	17.43	13.80	16.04	13.69	11.28
13	Duke Energy	16.13	17.10	N/A	18.22	17.91	17.45	17.46	13.76	12.69	13.32	17.28	16.13	N/A	N/A	N/A	N/A	N/A
14	Edison Int'l	14.02	18.80	17.92	14.77	13.05	12.70	9.71	11.81	10.32	9.72	12.36	16.03	12.99	11.74	37.59	6.97	7.78
15	El Paso Electric	17.15	22.50	18.66	18.33	16.38	15.88	14.47	12.60	10.72	10.79	11.89	15.26	16.92	26.72	22.03	18.26	22.99
16	Entergy Corp.	13.65	18.20	10.92	12.53	12.89	13.21	11.22	9.06	11.57	11.98	16.56	19.30	14.28	16.28	15.09	13.77	11.53
17	Eversource Energy	17.45	17.60	18.69	18.11	17.92	16.94	19.86	15.35	13.42	11.96	13.66	18.75	27.07	19.76	20.77	13.35	16.07
18	Exelon Corp.	14.14	14.00	N/A	12.58	16.02	13.43	19.08	11.30	10.97	11.49	17.97	18.22	16.53	15.37	12.99	11.77	10.46
19	FirstEnergy Corp.	17.69	16.20	N/A	17.02	39.79	13.06	21.10	22.39	11.75	13.02	15.64	15.59	14.23	16.07	14.13	22.47	12.95
20	Fortis Inc.	19.37	18.80	21.60	18.00	24.29	19.97	20.12	18.79	18.22	16.36	17.48	21.14	17.68	N/A	N/A	N/A	N/A
21	Great Plains Energy	15.70	18.30	17.98	19.37	16.47	14.19	15.53	16.11	12.10	16.03	20.55	16.35	18.30	13.96	12.59	12.23	11.09
22	Hawaiian Elec.	18.01	21.00	13.56	20.40	15.88	16.21	15.81	17.09	18.59	19.79	23.16	21.57	20.33	18.27	19.18	13.76	13.47
23	IDACORP, Inc.	15.92	20.60	19.06	16.22	14.67	13.45	12.41	11.54	11.83	10.20	13.93	18.19	15.07	16.70	15.49	26.51	18.88
24	MGE Energy	18.13	28.50	24.90	20.28	17.19	17.01	17.23	15.82	14.98	15.14	14.22	15.01	15.88	22.40	17.98	17.55	15.96
25	NextEra Energy, Inc.	15.57	17.50	20.71	16.89	17.25	16.57	14.43	11.54	10.83	13.42	14.48	18.90	13.65	17.88	13.65	17.88	13.60
26	NorthWestern Corp	16.81	18.50	17.19	18.36	16.24	16.86	15.72	12.62	12.90	11.54	13.87	21.74	25.95	17.09	N/A	N/A	N/A
27	OGE Energy	14.87	18.00	17.68	17.69	18.27	17.69	15.16	14.37	13.31	10.83	12.41	13.75	13.68	14.95	14.13	11.84	14.12
28	Otter Tail Corp.	24.32	22.40	20.19	18.20	18.84	21.12	21.75	47.48	55.10	31.16	30.06	19.02	17.35	15.40	17.34	17.77	16.01
29	PG&E Corp.	16.63	15.90	21.13	26.40	15.00	23.67	20.70	15.46	15.80	13.01	12.08	16.85	14.84	15.37	13.81	9.50	N/A
30	Pinnacle West Capital	15.56	19.70	18.74	16.04	15.89	15.27	14.35	14.60	12.57	13.74	16.07	14.93	13.69	19.24	15.80	13.96	14.43
31	PNM Resources	17.84	21.06	19.83	16.85	18.68	16.13	14.97	14.53	14.05	18.09	N/A	35.65	15.57	17.38	15.02	14.73	15.08
32	Portland General	16.16	20.60	19.06	17.71	15.32	16.88	13.98	12.37	12.00	14.40	16.30	11.94	23.35	N/A	N/A	N/A	N/A
33	PPL Corp.	14.20	14.80	N/A	13.92	14.08	12.84	10.88	10.52	11.93	25.69	17.64	17.26	14.10	15.12	12.51	10.59	11.06
34	Public Serv. Enterprise	13.13	15.20	N/A	12.41	12.61	13.50	12.79	10.40	10.37	10.04	13.65	16.54	17.81	16.74	14.26	10.58	10.00
35	SCANA Corp.	14.12	17.10	16.80	14.67	13.68	14.43	14.80	13.67	12.93	11.63	12.67	14.96	15.42	14.44	13.57	13.05	12.17
36	Sempra Energy	14.47	21.60	24.37	19.73	21.87	19.68	14.89	11.77	12.60	10.09	11.80	14.01	11.50	11.79	8.65	8.96	8.19
37	Southern Co.	15.72	18.10	N/A	15.85	16.04	16.19	16.97	15.85	14.90	13.52	16.13	15.95	16.19	15.92	14.68	14.83	14.63
38	Vectren Corp.	16.90	21.20	19.18	17.92	19.98	20.66	15.02	15.83	15.10	12.89	16.79	15.33	18.92	15.11	17.57	14.80	14.16
39	WEC Energy Group	15.90	19.40	19.95	21.33	17.71	16.50	15.76	14.25	14.01	13.35	14.77	16.47	15.97	14.46	17.51	12.43	10.46
40	Westar Energy	15.48	21.90	21.59	18.45	15.36	14.04	13.43	14.78	12.96	14.95	16.96	14.10	12.18	14.79	17.44	10.78	14.02
41	Xcel Energy Inc.	16.73	19.70	18.48	16.54	15.44	15.04	14.82	14.24	14.13	12.66	13.69	16.65	14.80	15.36	13.65	11.62	40.80
42	Average	16.23	19.36	19.28	18.00	17.39	16.38	15.69	15.30	14.28	13.56	15.18	17.74	16.47	16.52	16.57	13.70	14.31
43	Median	15.56	19.50	19.01	17.71	16.54	16.27	15.04	14.31	12.91	12.82	14.21	16.41	15.88	15.92	15.29	13.60	13.47

Sources:

[1] The Value Line Investment Survey Investment Analyzer Software.

[2] The Value Line Investment Survey, February 17, March 17, and April 28, 2017.

Portland General Electric Company

Electric Utilities
(Valuation Metrics)

		Market Price to Cash Flow (MP/CF) Ratio [1]																
Line	Company	16-Year Average (1)	2017 [2/a] (1)	2016 (2)	2015 (3)	2014 (4)	2013 (5)	2012 (6)	2011 (7)	2010 (8)	2009 (9)	2008 (10)	2007 (11)	2006 (12)	2005 (13)	2004 (14)	2003 (15)	2002 (16)
1	ALLETE	9.20	8.80	8.26	7.49	8.80	9.15	8.18	7.91	8.04	8.51	9.29	10.30	11.06	11.54	11.46	N/A	N/A
2	Alliant Energy	7.28	9.53	10.67	8.86	8.40	7.52	7.50	7.21	6.59	6.23	7.49	7.92	8.00	5.09	5.52	4.76	5.20
3	Ameren Corp.	6.78	7.58	7.44	6.87	6.95	6.61	5.48	5.02	4.23	4.25	6.35	7.69	8.57	8.57	8.24	6.74	7.96
4	American Electric Power	6.10	8.11	7.57	7.09	7.00	6.57	5.93	5.46	5.54	4.71	5.71	6.84	5.54	6.07	5.50	4.69	5.19
5	Avangrid, Inc.	9.14	6.97	N/A	11.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	6.38	7.55	7.63	6.76	7.30	6.21	6.88	6.40	5.80	4.06	5.12	7.58	5.30	6.58	7.58	5.36	5.90
7	Black Hills	7.50	8.69	9.33	8.06	8.81	8.03	6.04	7.85	6.16	4.25	11.26	7.62	6.92	7.57	6.69	6.89	5.92
8	CenterPoint Energy	4.81	6.49	5.96	5.75	6.25	6.56	5.15	5.39	4.70	4.05	4.29	5.17	3.94	4.70	4.26	2.08	2.16
9	CMS Energy Corp.	5.40	8.10	8.50	7.53	7.13	6.68	6.03	5.41	4.48	3.64	3.45	5.57	4.40	4.04	3.20	2.88	NMF
10	Consol. Edison	8.11	8.85	9.39	7.96	7.89	7.77	8.31	8.15	7.39	6.72	6.89	8.31	8.65	8.59	9.31	7.90	7.64
11	Dominion Resources	9.28	10.96	11.59	11.84	12.27	10.88	9.92	9.45	8.12	6.98	8.27	8.65	7.81	10.09	7.68	7.51	6.53
12	DTE Energy	6.02	8.56	8.64	8.52	6.42	6.65	5.91	5.18	4.69	3.59	4.90	5.73	5.21	5.54	6.00	5.62	5.20
13	Duke Energy	7.38	7.30	N/A	7.95	8.12	8.11	9.53	6.56	6.01	5.96	7.13	7.16	N/A	N/A	N/A	N/A	N/A
14	Edison Int'l	5.27	6.87	6.77	5.92	5.68	5.46	4.59	4.22	4.11	3.95	5.63	7.01	5.87	5.61	6.84	2.82	2.96
15	El Paso Electric	5.67	7.77	7.46	6.47	6.33	6.19	5.78	5.16	4.31	3.98	4.95	6.44	6.25	6.67	4.65	3.90	4.39
16	Entergy Corp.	5.73	4.26	4.01	4.11	4.21	4.03	4.23	3.90	4.66	5.68	7.96	9.21	7.16	8.76	7.12	6.84	5.57
17	Eversource Energy	6.49	10.20	10.14	10.12	10.14	8.08	9.30	6.99	4.97	4.61	4.12	6.18	6.02	3.55	3.78	2.85	2.75
18	Exelon Corp.	6.27	4.08	N/A	4.70	5.09	4.61	5.54	5.86	5.10	5.98	9.65	9.89	8.62	7.97	6.29	5.71	4.97
19	FirstEnergy Corp.	6.25	4.41	N/A	5.38	7.43	6.15	7.42	7.33	4.49	4.91	7.58	7.89	7.53	6.04	5.15	6.90	5.10
20	Fortis Inc.	8.20	8.16	10.46	7.29	9.25	7.93	8.09	8.38	7.40	6.76	7.58	9.18	7.89	N/A	N/A	N/A	N/A
21	Great Plains Energy	6.48	8.03	8.63	6.66	6.45	5.73	6.09	5.74	4.49	5.06	7.71	7.13	7.68	6.70	6.52	5.92	5.14
22	Hawaiian Elec.	7.92	9.07	7.44	9.25	7.64	8.15	8.05	7.73	7.81	6.95	9.10	7.95	8.47	8.29	8.44	6.12	6.20
23	IDACORP, Inc.	7.89	11.49	10.95	9.37	8.59	7.78	7.05	6.64	6.52	5.31	7.10	8.23	7.73	7.55	7.15	7.27	7.53
24	MGE Energy	10.89	17.77	15.66	12.53	11.42	11.20	10.77	9.48	9.05	8.40	8.42	9.23	9.30	11.73	11.04	10.20	8.09
25	NextEra Energy, Inc.	7.17	8.94	9.32	7.93	7.98	7.60	7.58	5.98	5.33	6.09	7.34	9.02	6.51	6.71	6.71	5.97	5.77
26	NorthWestern Corp	7.51	8.49	8.65	8.99	9.01	7.61	6.85	5.89	5.79	5.05	5.57	8.45	9.39	7.31	8.13	N/A	N/A
27	OGE Energy	7.58	9.36	9.03	9.25	10.65	9.93	7.35	7.48	6.61	5.37	6.43	7.58	7.50	7.04	6.73	5.62	5.39
28	Otter Tail Corp.	9.07	10.67	9.38	9.04	9.45	9.58	8.43	9.04	8.07	8.01	11.65	9.53	8.66	8.18	9.01	8.13	8.33
29	PG&E Corp.	6.25	6.97	7.26	7.24	5.65	6.84	5.86	5.32	5.42	4.71	4.61	5.84	5.28	5.07	5.13	4.05	14.69
30	Pinnacle West Capital	5.96	8.19	7.89	6.91	7.03	6.85	6.34	5.80	5.65	3.84	4.19	4.76	4.48	7.48	5.88	4.80	5.21
31	PNM Resources	6.71	7.94	7.64	6.95	7.48	6.47	5.80	4.94	4.58	4.53	7.10	10.67	7.50	7.62	6.84	5.55	5.72
32	Portland General	5.61	7.31	7.12	6.73	5.49	6.06	5.08	4.86	4.13	4.63	4.81	5.34	5.74	N/A	N/A	N/A	N/A
33	PPL Corp.	7.36	9.24	N/A	8.73	7.32	6.59	5.87	5.98	7.46	8.82	9.17	8.90	7.58	7.57	6.49	5.41	5.30
34	Public Serv. Enterprise	7.12	7.12	N/A	6.66	6.48	6.40	6.40	6.03	6.04	6.20	8.46	9.83	8.41	8.59	7.17	6.79	6.24
35	SCANA Corp.	7.18	9.64	9.59	8.33	7.50	7.49	7.40	6.75	6.52	5.88	6.38	7.15	7.03	5.40	6.86	6.59	6.36
36	Sempra Energy	7.56	10.04	10.88	9.99	10.77	9.37	7.26	6.13	6.53	6.07	7.07	8.61	7.22	6.96	5.16	4.85	4.00
37	Southern Co.	8.21	8.37	N/A	8.23	8.42	8.30	8.75	8.22	7.79	7.08	8.18	8.62	8.47	8.41	8.28	8.28	7.83
38	Vectren Corp.	7.00	9.13	8.60	7.82	7.57	6.82	5.79	5.81	5.58	5.24	6.90	6.53	7.37	7.06	7.63	7.27	6.92
39	WEC Energy Group	8.21	10.43	10.95	12.90	10.27	9.58	9.24	8.43	8.15	6.87	7.57	7.84	7.27	6.40	6.27	4.91	4.27
40	Westar Energy	6.92	10.99	10.86	9.05	7.93	7.23	6.71	6.67	5.51	5.32	7.09	6.88	5.81	7.00	6.54	4.24	2.94
41	Xcel Energy Inc.	6.33	7.83	8.10	7.62	7.31	7.00	6.85	6.47	6.28	5.43	5.71	6.51	5.54	5.62	5.31	4.27	5.46
42	Average	7.07	8.54	8.88	8.05	7.85	7.39	6.98	6.53	6.00	5.59	6.95	7.72	7.12	7.13	6.77	5.70	5.85
43	Median	6.94	8.37	8.64	7.93	7.54	7.12	6.85	6.27	5.80	5.35	7.09	7.76	7.37	7.04	6.71	5.62	5.52

Sources:

[1] The Value Line Investment Survey Investment Analyzer Software.

[2] The Value Line Investment Survey, February 17, March 17, and April 28, 2017.

Note:

[a] Based on the average of the high and low price for 2017 and the projected 2017 Cash Flow per share, published in The Value Line Investment Survey, February 17, March 17, and April 28, 2017.

Portland General Electric Company

Electric Utilities
(Valuation Metrics)

		Market Price to Book Value (MP/BV) Ratio [1]													
Line	Company	13-Year Average (1)	2017 [2/a] (2)	2016 (3)	2015 (4)	2014 (5)	2013 (6)	2012 (7)	2011 (8)	2010 (9)	2009 (10)	2008 (11)	2007 (12)	2006 (13)	2005 (14)
1	ALLETE	1.57	1.64	1.53	1.37	1.42	1.51	1.34	1.35	1.28	1.15	1.55	1.89	2.09	2.22
2	Alliant Energy	1.62	2.18	2.17	1.86	1.86	1.70	1.57	1.46	1.31	1.04	1.33	1.67	1.52	1.33
3	Ameren Corp.	1.34	1.76	1.67	1.46	1.45	1.29	1.18	0.90	0.83	0.78	1.25	1.60	1.62	1.68
4	American Electric Power	1.49	1.75	1.81	1.55	1.54	1.40	1.31	1.23	1.23	1.08	1.48	1.85	1.56	1.57
5	Avangrid, Inc.	0.75	0.78	N/A	0.72	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	1.25	1.48	1.57	1.36	1.33	1.25	1.21	1.19	1.07	0.94	1.11	1.29	1.30	1.13
7	Black Hills	1.47	1.99	1.94	1.59	1.79	1.62	1.21	1.14	1.07	0.83	1.22	1.57	1.47	1.63
8	CenterPoint Energy	2.46	3.19	2.73	2.43	2.27	2.30	1.99	1.87	1.96	1.77	2.49	3.13	2.75	3.06
9	CMS Energy Corp.	1.85	2.63	2.72	2.43	2.26	2.09	1.91	1.66	1.48	1.10	1.23	1.82	1.42	1.32
10	Consol. Edison	1.39	1.52	1.58	1.42	1.34	1.38	1.47	1.38	1.22	1.08	1.17	1.47	1.47	1.52
11	Dominion Resources	2.67	2.95	3.15	3.34	3.55	2.97	2.84	2.37	2.01	1.80	2.42	2.69	2.07	2.50
12	DTE Energy	1.40	1.91	1.82	1.65	1.62	1.51	1.35	1.20	1.16	0.89	1.10	1.35	1.29	1.39
13	Duke Energy	1.14	1.29	N/A	1.29	1.28	1.19	1.12	1.11	1.00	0.91	1.06	1.15	N/A	N/A
14	Edison Int'l	1.62	1.96	1.92	1.76	1.68	1.57	1.53	1.24	1.07	1.04	1.56	2.05	1.80	1.93
15	El Paso Electric	1.52	1.74	1.68	1.48	1.52	1.49	1.59	1.64	1.17	0.98	1.33	1.69	1.71	1.76
16	Entergy Corp.	1.70	1.57	1.67	1.40	1.33	1.21	1.31	1.35	1.62	1.66	2.44	2.65	1.89	2.01
17	Eversource Energy	1.38	1.57	1.64	1.53	1.47	1.38	1.28	1.50	1.31	1.12	1.31	1.60	1.22	1.05
18	Exelon Corp.	2.46	1.20	N/A	1.14	1.28	1.17	1.46	1.95	2.07	2.57	4.39	4.79	3.89	3.60
19	FirstEnergy Corp.	1.55	1.09	N/A	1.16	1.15	1.28	1.44	1.33	1.36	1.54	2.52	2.23	1.92	1.64
20	Fortis Inc.	1.48	1.26	1.26	1.33	1.35	1.45	1.59	1.59	1.56	1.33	1.48	1.63	1.96	N/A
21	Great Plains Energy	1.19	1.13	1.17	1.12	1.11	1.02	0.96	0.93	0.87	0.80	1.11	1.66	1.77	1.86
22	Hawaiian Elec.	1.60	1.71	1.63	1.71	1.49	1.54	1.62	1.54	1.44	1.16	1.61	1.57	2.01	1.78
23	IDACORP, Inc.	1.33	1.84	1.76	1.54	1.45	1.33	1.19	1.17	1.13	0.92	1.09	1.26	1.37	1.22
24	MGE Energy	2.00	3.03	2.60	2.10	2.10	2.06	1.92	1.75	1.65	1.54	1.62	1.75	1.83	2.09
25	NextEra Energy, Inc.	1.95	2.24	2.30	2.09	2.15	1.93	1.74	1.55	1.49	1.70	2.06	2.34	1.80	1.93
26	NorthWestern Corp	1.44	1.62	1.68	1.60	1.54	1.56	1.42	1.35	1.22	1.07	1.15	1.48	1.65	1.42
27	OGE Energy	1.85	1.94	1.73	1.79	2.22	2.24	1.94	1.90	1.70	1.37	1.52	1.98	1.91	1.80
28	Otter Tail Corp.	1.70	2.13	1.90	1.78	1.90	1.96	1.58	1.35	1.19	1.18	1.71	1.93	1.76	1.74
29	PG&E Corp.	1.59	1.71	1.69	1.57	1.39	1.38	1.41	1.46	1.56	1.41	1.50	1.94	1.83	1.84
30	Pinnacle West Capital	1.34	1.82	1.72	1.52	1.44	1.47	1.39	1.25	1.14	0.95	1.00	1.26	1.26	1.25
31	PNM Resources	1.10	1.51	1.56	1.33	1.21	1.09	0.98	0.80	0.69	0.56	0.66	1.23	1.21	1.45
32	Portland General	1.26	1.63	1.56	1.42	1.37	1.28	1.14	1.09	0.94	0.92	1.05	1.32	1.36	N/A
33	PPL Corp.	2.13	2.24	N/A	2.24	1.64	1.55	1.58	1.47	1.61	2.10	3.19	3.05	2.43	2.50
34	Public Serv. Enterprise	1.94	1.68	N/A	1.58	1.57	1.44	1.46	1.59	1.67	1.78	2.58	2.99	2.46	2.45
35	SCANA Corp.	1.51	1.70	1.74	1.47	1.48	1.48	1.48	1.36	1.33	1.20	1.45	1.62	1.64	1.72
36	Sempra Energy	1.74	1.99	2.00	2.17	2.20	1.84	1.53	1.28	1.35	1.32	1.60	1.87	1.70	1.73
37	Southern Co.	2.03	1.66	N/A	1.99	2.02	2.04	2.15	1.99	1.83	1.73	2.12	2.24	2.23	2.35
38	Vectren Corp.	1.81	2.41	2.29	2.11	2.08	1.82	1.57	1.53	1.41	1.34	1.64	1.74	1.77	1.82
39	WEC Energy Group	1.85	1.99	2.09	1.82	2.34	2.21	2.05	1.81	1.65	1.40	1.57	1.77	1.71	1.62
40	Westar Energy	1.37	1.99	1.95	1.49	1.44	1.33	1.26	1.20	1.10	0.93	1.10	1.36	1.30	1.41
41	Xcel Energy Inc.	1.50	1.89	1.88	1.66	1.55	1.50	1.51	1.41	1.32	1.19	1.30	1.53	1.40	1.38
42	Average	1.64	1.84	1.89	1.67	1.68	1.60	1.51	1.43	1.35	1.25	1.63	1.90	1.78	1.80
43	Median	1.54	1.75	1.75	1.57	1.53	1.49	1.47	1.37	1.31	1.15	1.48	1.71	1.71	1.73

Sources:

[1] The Value Line Investment Survey Investment Analyzer Software.

[2] The Value Line Investment Survey, February 17, March 17, and April 28, 2017.

Note:

[a] Based on the average of the high and low price for 2017 and the projected 2017 Book Value per share, published in The Value Line Investment Survey, February 17, March 17, and April 28, 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

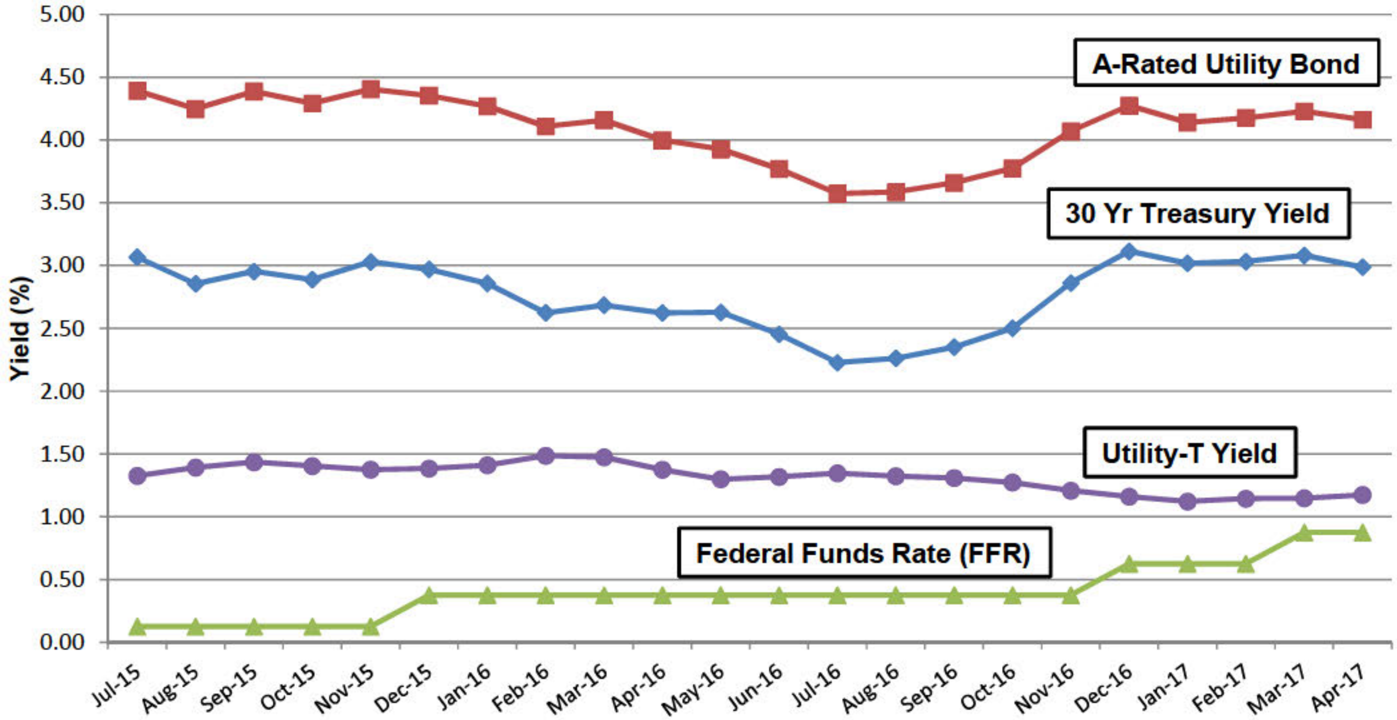
EXHIBIT ICNU/204

TIMELINE OF FEDERAL FUNDS RATE

June 16, 2017

Portland General Electric Company

Timeline of Federal Funds Rate Increases



Fed FFR Actions:

December 2015	0.25	→	0.50
December 2016	0.50	→	0.75
March 2017	0.75	→	1.00

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Moody's Credit Trends, https://credittrends.moodys.com/

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/205

PROXY GROUP

June 16, 2017

Portland General Electric Company

Proxy Group

Line	Company	Credit Ratings[1] S&P (1)	Credit Ratings[1] Moody's (2)	Common Equity Ratios SNL[1] (3)	Common Equity Ratios Value Line[2] (4)
1	ALLETE, Inc.	BBB+	A3	54.9%	58.0%
2	Alliant Energy Corporation	A-	Baa1	44.3%	48.0%
3	American Electric Power Company, Inc.	A-	Baa1	43.8%	50.0%
4	Ameren Corporation	BBB+	Baa1	47.1%	51.3%
5	CenterPoint Energy, Inc.	A-	Baa1	28.7%	31.5%
6	CMS Energy Corporation	BBB+	Baa1	29.7%	32.6%
7	Consolidated Edison, Inc.	A-	A3	47.4%	49.2%
8	Dominion Resources, Inc.	BBB+	Baa2	28.1%	32.6%
9	DTE Energy Company	BBB+	Baa1	42.3%	44.4%
10	Edison International	BBB+	A3	45.0%	49.2%
11	El Paso Electric Company	BBB	Baa1	44.1%	47.3%
12	Entergy Corporation	BBB+	Baa2	34.3%	35.5%
13	IDACORP, Inc.	BBB	Baa1	54.9%	55.2%
14	MGE Energy, Inc.	N/A	N/A	65.2%	65.4%
15	OGE Energy Corp.	A-	A3	54.6%	58.9%
16	Otter Tail Corporation	BBB	N/A	53.5%	57.0%
17	PG&E Corporation	A-	Baa1	48.9%	52.1%
18	Pinnacle West Capital Corporation	A-	A3	51.9%	54.4%
19	Portland General Electric Company	BBB	A3	49.9%	51.6%
20	PPL Corporation	A-	Baa2	34.0%	35.7%
21	Public Service Enterprise Group Incorporated	BBB+	Baa2	52.7%	54.7%
22	SCANA Corporation	BBB+	Baa3	43.5%	46.9%
23	Sempra Energy	BBB+	Baa1	40.0%	47.3%
24	Vectren Corporation	A-	N/A	48.1%	52.7%
25	Xcel Energy Inc.	A-	A3	42.6%	43.7%
26	**Average**	**BBB+**	**Baa1**	**45.2%**	**48.2%**
27	**Portland General Electric Company**	**BBB**[3]	**A3**[3]	**48.65%**[4]	

Sources:
[1] SNL Financial, Downloaded on May 24, 2017.
[2] *The Value Line Investment Survey* , March 17, April 28, and May 19, 2017.
[3] Exhibits PGE/1100, Villadsen/3 and PGE/1000, Hager - Liddle/10.
[4] Exhibit ICNU/202.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/206

CONSENSUS ANALYSTS' GROWTH RATES

June 16, 2017

Portland General Electric Company

Consensus Analysts' Growth Rates

		Zacks		SNL		Reuters		Average of
Line	**Company**	**Estimated Growth %[1]**	**Number of Estimates**	**Estimated Growth %[2]**	**Number of Estimates**	**Estimated Growth %[3]**	**Number of Estimates**	**Growth Rates**
		(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**	**(7)**
1	ALLETE, Inc.	6.10%	N/A	6.60%	2	5.00%	1	5.90%
2	Alliant Energy Corporation	5.50%	N/A	6.00%	4	6.35%	2	5.95%
3	American Electric Power Company, Inc.	5.60%	N/A	4.12%	7	2.31%	3	4.01%
4	Ameren Corporation	6.50%	N/A	6.10%	3	6.25%	2	6.28%
5	CenterPoint Energy, Inc.	5.00%	N/A	6.58%	6	5.89%	4	5.82%
6	CMS Energy Corporation	6.00%	N/A	7.10%	6	7.52%	5	6.87%
7	Consolidated Edison, Inc.	3.60%	N/A	3.69%	3	3.97%	3	3.75%
8	Dominion Resources, Inc.	6.00%	N/A	5.60%	4	3.96%	5	5.19%
9	DTE Energy Company	5.90%	N/A	5.71%	5	4.58%	4	5.40%
10	Edison International	6.30%	N/A	6.01%	5	4.11%	3	5.47%
11	El Paso Electric Company	7.90%	N/A	7.90%	2	6.50%	1	7.43%
12	Entergy Corporation	0.00%	N/A	6.00%	2	- 6.78%	2	6.00%
13	IDACORP, Inc.	4.00%	N/A	4.00%	1	4.00%	2	4.00%
14	MGE Energy, Inc.	N/A	N/A	4.00%	1	N/A	N/A	4.00%
15	OGE Energy Corp.	5.30%	N/A	5.00%	2	6.30%	2	5.53%
16	Otter Tail Corporation	N/A	N/A	6.00%	2	5.20%	1	5.60%
17	PG&E Corporation	4.40%	N/A	4.52%	7	3.59%	3	4.17%
18	Pinnacle West Capital Corporation	5.10%	N/A	5.54%	4	6.05%	6	5.56%
19	Portland General Electric Company	5.30%	N/A	4.35%	2	5.55%	2	5.07%
20	PPL Corporation	5.00%	N/A	5.17%	3	2.44%	3	4.20%
21	Public Service Enterprise Group Incorporated	2.40%	N/A	5.10%	4	0.40%	1	2.63%
22	SCANA Corporation	5.30%	N/A	5.38%	4	5.60%	1	5.43%
23	Sempra Energy	8.70%	N/A	7.97%	3	9.90%	3	8.86%
24	Vectren Corporation	5.70%	N/A	5.67%	3	5.50%	2	5.62%
25	Xcel Energy Inc.	5.40%	N/A	5.51%	7	5.32%	3	5.41%
26	**Average**	**5.50%**	**N/A**	**5.58%**	**4**	**5.06%**	**3**	**5.37%**

Sources:
[1] Zacks Elite, http://www.zackselite.com/, downloaded on May 19, 2017.
[2] SNL Interactive, http://www.snl.com/, downloaded on May 19, 2017.
[3] Reuters, http://www.reuters.com/, downloaded on May 19, 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/207

CONSTANT GROWTH DCF MODEL
(CONSENSUS ANALYSTS' GROWTH RATES)

June 16, 2017

Portland General Electric Company

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$68.09	5.90%	$2.14	3.33%	9.23%
2	Alliant Energy Corporation	$39.46	5.95%	$1.26	3.38%	9.33%
3	American Electric Power Company, Inc.	$67.11	4.01%	$2.36	3.66%	7.67%
4	Ameren Corporation	$54.75	6.28%	$1.76	3.42%	9.70%
5	CenterPoint Energy, Inc.	$27.66	5.82%	$1.07	4.10%	9.92%
6	CMS Energy Corporation	$44.89	6.87%	$1.33	3.17%	10.04%
7	Consolidated Edison, Inc.	$77.87	3.75%	$2.76	3.68%	7.43%
8	Dominion Resources, Inc.	$77.18	5.19%	$3.02	4.12%	9.30%
9	DTE Energy Company	$102.61	5.40%	$3.30	3.39%	8.79%
10	Edison International	$79.40	5.47%	$2.17	2.88%	8.36%
11	El Paso Electric Company	$50.03	7.43%	$1.24	2.66%	10.10%
12	Entergy Corporation	$75.76	6.00%	$3.48	4.87%	10.87%
13	IDACORP, Inc.	$83.12	4.00%	$2.20	2.75%	6.75%
14	MGE Energy, Inc.	$63.95	4.00%	$1.23	2.00%	6.00%
15	OGE Energy Corp.	$35.25	5.53%	$1.21	3.62%	9.16%
16	Otter Tail Corporation	$37.93	5.60%	$1.28	3.56%	9.16%
17	PG&E Corporation	$66.50	4.17%	$1.96	3.07%	7.24%
18	Pinnacle West Capital Corporation	$83.62	5.56%	$2.62	3.31%	8.87%
19	Portland General Electric Company	$44.91	5.07%	$1.28	2.99%	8.06%
20	PPL Corporation	$37.43	4.20%	$1.58	4.40%	8.60%
21	Public Service Enterprise Group Incorporated	$44.49	2.63%	$1.72	3.97%	6.60%
22	SCANA Corporation	$66.79	5.43%	$2.45	3.87%	9.29%
23	Sempra Energy	$110.71	8.86%	$3.29	3.23%	12.09%
24	Vectren Corporation	$58.03	5.62%	$1.68	3.06%	8.68%
25	Xcel Energy Inc.	$44.35	5.41%	$1.44	3.42%	8.83%
26	**Average**	**$61.68**	**5.37%**	**$1.99**	**3.44%**	**8.80%**
27	**Median**					**8.87%**

Sources:
[1] SNL Financial, Downloaded on May 24, 2017.
[2] Exhibit ICNU/206.
[3] *The Value Line Investment Survey* , March 17, April 28, and May 19, 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/208

PAYOUT RATIOS

June 16, 2017

Portland General Electric Company

Payout Ratios

Line	Company	Dividends Per Share 2016 (1)	Dividends Per Share Projected (2)	Earnings Per Share 2016 (3)	Earnings Per Share Projected (4)	Payout Ratio 2016 (5)	Payout Ratio Projected (6)
1	ALLETE, Inc.	$2.08	$2.50	$3.14	$4.00	66.24%	62.50%
2	Alliant Energy Corporation	$1.18	$1.58	$1.65	$2.50	71.52%	63.20%
3	American Electric Power Company, Inc.	$2.27	$2.90	$4.23	$4.75	53.66%	61.05%
4	Ameren Corporation	$1.72	$2.15	$2.68	$3.50	64.18%	61.43%
5	CenterPoint Energy, Inc.	$1.03	$1.23	$1.00	$1.65	103.00%	74.55%
6	CMS Energy Corporation	$1.24	$1.70	$1.98	$2.75	62.63%	61.82%
7	Consolidated Edison, Inc.	$2.68	$3.08	$3.94	$4.50	68.02%	68.44%
8	Dominion Resources, Inc.	$2.80	$4.20	$3.44	$4.50	81.40%	93.33%
9	DTE Energy Company	$3.06	$4.30	$4.83	$6.50	63.35%	66.15%
10	Edison International	$1.98	$2.90	$3.94	$5.00	50.25%	58.00%
11	El Paso Electric Company	$1.23	$1.75	$2.39	$3.00	51.46%	58.33%
12	Entergy Corporation	$3.42	$3.80	$6.88	$5.25	49.71%	72.38%
13	IDACORP, Inc.	$2.08	$2.90	$3.94	$4.75	52.79%	61.05%
14	MGE Energy, Inc.	$1.21	$1.45	$2.18	$3.25	55.50%	44.62%
15	OGE Energy Corp.	$1.16	$1.75	$1.69	$2.50	68.64%	70.00%
16	Otter Tail Corporation	$1.25	$1.38	$1.60	$2.20	78.13%	62.73%
17	PG&E Corporation	$1.93	$2.90	$2.83	$4.50	68.20%	64.44%
18	Pinnacle West Capital Corporation	$2.56	$3.25	$3.95	$5.25	64.81%	61.90%
19	Portland General Electric Company	$1.26	$1.70	$2.16	$3.00	58.33%	56.67%
20	PPL Corporation	$1.52	$1.82	$2.79	$2.75	54.48%	66.18%
21	Public Service Enterprise Group Incorporated	$1.64	$2.10	$2.83	$3.50	57.95%	60.00%
22	SCANA Corporation	$2.30	$2.90	$4.16	$5.00	55.29%	58.00%
23	Sempra Energy	$3.02	$4.55	$4.24	$7.50	71.23%	60.67%
24	Vectren Corporation	$1.62	$2.00	$2.55	$3.45	63.53%	57.97%
25	Xcel Energy Inc.	$1.36	$1.80	$2.21	$2.75	61.54%	65.45%
26	**Average**	**$1.90**	**$2.50**	**$3.09**	**$3.93**	**63.83%**	**63.64%**

Source:
The Value Line Investment Survey , March 17, April 28, and May 19, 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/209

SUSTAINABLE GROWTH RATE

June 16, 2017

Portland General Electric Company

Sustainable Growth Rate

Line	Company	Dividends Per Share (1)	Earnings Per Share (2)	Book Value Per Share (3)	Book Value Growth (4)	ROE (5)	Adjustment Factor (6)	Adjusted ROE (7)	Payout Ratio (8)	Retention Rate (9)	Internal Growth Rate (10)	Sustainable Growth Rate (11)
		3 to 5 Year Projections										
1	ALLETE, Inc.	$2.50	$4.00	$45.50	3.58%	8.79%	1.02	8.95%	62.50%	37.50%	3.35%	4.10%
2	Alliant Energy Corporation	$1.58	$2.50	$19.05	2.35%	13.12%	1.01	13.28%	63.20%	36.80%	4.89%	5.84%
3	American Electric Power Company, Inc.	$2.90	$4.75	$43.25	4.10%	10.98%	1.02	11.20%	61.05%	38.95%	4.36%	4.37%
4	Ameren Corporation	$2.15	$3.50	$35.50	3.93%	9.86%	1.02	10.05%	61.43%	38.57%	3.88%	3.88%
5	CenterPoint Energy, Inc.	$1.23	$1.65	$9.75	3.96%	16.92%	1.02	17.25%	74.55%	25.45%	4.39%	4.88%
6	CMS Energy Corporation	$1.70	$2.75	$21.00	6.64%	13.10%	1.03	13.52%	61.82%	38.18%	5.16%	6.51%
7	Consolidated Edison, Inc.	$3.08	$4.50	$55.00	3.25%	8.18%	1.02	8.31%	68.44%	31.56%	2.62%	3.05%
8	Dominion Resources, Inc.	$4.20	$4.50	$24.25	0.84%	18.56%	1.00	18.63%	93.33%	6.67%	1.24%	1.24%
9	DTE Energy Company	$4.30	$6.50	$62.00	4.30%	10.48%	1.02	10.70%	66.15%	33.85%	3.62%	4.49%
10	Edison International	$2.90	$5.00	$46.25	4.67%	10.81%	1.02	11.06%	58.00%	42.00%	4.64%	4.64%
11	El Paso Electric Company	$1.75	$3.00	$32.25	3.99%	9.30%	1.02	9.48%	58.33%	41.67%	3.95%	4.16%
12	Entergy Corporation	$3.80	$5.25	$52.00	2.88%	10.10%	1.01	10.24%	72.38%	27.62%	2.83%	2.83%
13	IDACORP, Inc.	$2.90	$4.75	$51.50	3.80%	9.22%	1.02	9.40%	61.05%	38.95%	3.66%	3.75%
14	MGE Energy, Inc.	$1.45	$3.25	$25.70	4.23%	12.65%	1.02	12.91%	44.62%	55.38%	7.15%	8.71%
15	OGE Energy Corp.	$1.75	$2.50	$20.75	3.78%	12.05%	1.02	12.27%	70.00%	30.00%	3.68%	3.87%
16	Otter Tail Corporation	$1.38	$2.20	$23.20	6.38%	9.48%	1.03	9.78%	62.73%	37.27%	3.64%	6.42%
17	PG&E Corporation	$2.90	$4.50	$45.50	5.15%	9.89%	1.03	10.14%	64.44%	35.56%	3.60%	4.56%
18	Pinnacle West Capital Corporation	$3.25	$5.25	$51.75	3.70%	10.14%	1.02	10.33%	61.90%	38.10%	3.93%	4.38%
19	Portland General Electric Company	$1.70	$3.00	$31.00	3.30%	9.68%	1.02	9.83%	56.67%	43.33%	4.26%	4.43%
20	PPL Corporation	$1.82	$2.75	$19.25	5.74%	14.29%	1.03	14.68%	66.18%	33.82%	4.97%	7.22%
21	Public Service Enterprise Group Incorporated	$2.10	$3.50	$31.25	3.74%	11.20%	1.02	11.41%	60.00%	40.00%	4.56%	4.59%
22	SCANA Corporation	$2.90	$5.00	$50.00	4.53%	10.00%	1.02	10.22%	58.00%	42.00%	4.29%	4.85%
23	Sempra Energy	$4.55	$7.50	$57.75	2.21%	12.99%	1.01	13.13%	60.67%	39.33%	5.16%	5.16%
24	Vectren Corporation	$2.00	$3.45	$27.05	4.87%	12.75%	1.02	13.06%	57.97%	42.03%	5.49%	6.76%
25	Xcel Energy Inc.	$1.80	$2.75	$26.25	3.85%	10.48%	1.02	10.67%	65.45%	34.55%	3.69%	3.69%
26	**Average**	**$2.50**	**$3.93**	**$36.27**	**3.99%**	**11.40%**	**1.02**	**11.62%**	**63.64%**	**36.36%**	**4.12%**	**4.74%**

Sources and Notes:
Cols. (1), (2) and (3): *The Value Line Investment Survey*, March 17, April 28, and May 19, 2017.
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/number of years projected) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

Portland General Electric Company

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1] (1)	2016 Book Value Per Share[2] (2)	Market to Book Ratio (3)	Common Shares Outstanding (in Millions)[2] 2016 (4)	Common Shares Outstanding (in Millions)[2] 3-5 Years (5)	Growth (6)	S Factor[3] (7)	V Factor[4] (8)	S * V (9)
1	ALLETE, Inc.	$68.09	$38.17	1.78	49.60	52.00	0.95%	1.69%	43.94%	0.74%
2	Alliant Energy Corporation	$39.46	$16.96	2.33	227.67	236.00	0.72%	1.68%	57.02%	0.96%
3	American Electric Power Company, Inc.	$67.11	$35.38	1.90	491.71	492.00	0.01%	0.02%	47.28%	0.01%
4	Ameren Corporation	$54.75	$29.27	1.87	242.63	242.63	0.00%	0.00%	46.54%	0.00%
5	CenterPoint Energy, Inc.	$27.66	$8.03	3.44	430.68	435.00	0.20%	0.69%	70.97%	0.49%
6	CMS Energy Corporation	$44.89	$15.23	2.95	279.21	289.00	0.69%	2.04%	66.07%	1.35%
7	Consolidated Edison, Inc.	$77.87	$46.88	1.66	305.00	315.00	0.65%	1.08%	39.79%	0.43%
8	Dominion Resources, Inc.	$77.18	$23.26	3.32	627.80	615.00	- 0.41%	- 1.36%	69.86%	- 0.95%
9	DTE Energy Company	$102.61	$50.22	2.04	179.43	187.00	0.83%	1.70%	51.06%	0.87%
10	Edison International	$79.40	$36.82	2.16	325.81	325.81	0.00%	0.00%	53.63%	0.00%
11	El Paso Electric Company	$50.03	$26.52	1.89	40.52	41.00	0.24%	0.44%	46.99%	0.21%
12	Entergy Corporation	$75.76	$45.12	1.68	179.13	179.00	- 0.01%	- 0.02%	40.44%	- 0.01%
13	IDACORP, Inc.	$83.12	$42.74	1.94	50.40	50.65	0.10%	0.19%	48.58%	0.09%
14	MGE Energy, Inc.	$63.95	$20.89	3.06	34.67	36.00	0.76%	2.31%	67.33%	1.56%
15	OGE Energy Corp.	$35.25	$17.24	2.04	199.70	201.50	0.18%	0.37%	51.09%	0.19%
16	Otter Tail Corporation	$37.93	$17.03	2.23	39.35	44.00	2.26%	5.03%	55.10%	2.77%
17	PG&E Corporation	$66.50	$35.39	1.88	506.89	535.00	1.09%	2.04%	46.78%	0.95%
18	Pinnacle West Capital Corporation	$83.62	$43.15	1.94	111.34	114.00	0.47%	0.92%	48.40%	0.44%
19	Portland General Electric Company	$44.91	$26.35	1.70	88.95	90.00	0.23%	0.40%	41.32%	0.17%
20	PPL Corporation	$37.43	$14.56	2.57	679.73	730.00	1.44%	3.69%	61.10%	2.26%
21	Public Service Enterprise Group Incorporated	$44.49	$26.01	1.71	504.87	506.00	0.04%	0.08%	41.54%	0.03%
22	SCANA Corporation	$66.79	$40.06	1.67	142.90	149.00	0.84%	1.40%	40.02%	0.56%
23	Sempra Energy	$110.71	$51.77	2.14	250.15	236.00	- 1.16%	- 2.48%	53.24%	- 1.32%
24	Vectren Corporation	$58.03	$21.33	2.72	82.90	86.00	0.74%	2.01%	63.25%	1.27%
25	Xcel Energy Inc.	$44.35	$21.73	2.04	507.22	507.00	- 0.01%	- 0.02%	51.00%	- 0.01%
26	**Average**	**$61.68**	**$30.00**	**2.19**	**263.13**	**267.78**	**0.59%**	**1.32%**	**52.09%**	**0.73%**

Sources and Notes:

[1] SNL Financial, Downloaded on May 24, 2017.

[2] *The Value Line Investment Survey* , March 17, April 28, and May 19, 2017.

[3] Expected Growth in the Number of Shares, Column (3) * Column (6).

[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/210

CONSTANT GROWTH DCF MODEL
(SUSTAINABLE GROWTH RATE)

June 16, 2017

Portland General Electric Company

Constant Growth DCF Model
(Sustainable Growth Rate)

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	ALLETE, Inc.	$68.09	4.10%	$2.14	3.27%	7.37%
2	Alliant Energy Corporation	$39.46	5.84%	$1.26	3.38%	9.22%
3	American Electric Power Company, Inc.	$67.11	4.37%	$2.36	3.67%	8.04%
4	Ameren Corporation	$54.75	3.88%	$1.76	3.34%	7.22%
5	CenterPoint Energy, Inc.	$27.66	4.88%	$1.07	4.06%	8.94%
6	CMS Energy Corporation	$44.89	6.51%	$1.33	3.16%	9.66%
7	Consolidated Edison, Inc.	$77.87	3.05%	$2.76	3.65%	6.70%
8	Dominion Resources, Inc.	$77.18	1.24%	$3.02	3.96%	5.20%
9	DTE Energy Company	$102.61	4.49%	$3.30	3.36%	7.85%
10	Edison International	$79.40	4.64%	$2.17	2.86%	7.50%
11	El Paso Electric Company	$50.03	4.16%	$1.24	2.58%	6.74%
12	Entergy Corporation	$75.76	2.83%	$3.48	4.72%	7.55%
13	IDACORP, Inc.	$83.12	3.75%	$2.20	2.75%	6.50%
14	MGE Energy, Inc.	$63.95	8.71%	$1.23	2.09%	10.80%
15	OGE Energy Corp.	$35.25	3.87%	$1.21	3.57%	7.43%
16	Otter Tail Corporation	$37.93	6.42%	$1.28	3.59%	10.01%
17	PG&E Corporation	$66.50	4.56%	$1.96	3.08%	7.64%
18	Pinnacle West Capital Corporation	$83.62	4.38%	$2.62	3.27%	7.65%
19	Portland General Electric Company	$44.91	4.43%	$1.28	2.98%	7.40%
20	PPL Corporation	$37.43	7.22%	$1.58	4.53%	11.75%
21	Public Service Enterprise Group Incorporated	$44.49	4.59%	$1.72	4.04%	8.64%
22	SCANA Corporation	$66.79	4.85%	$2.45	3.85%	8.70%
23	Sempra Energy	$110.71	5.16%	$3.29	3.13%	8.29%
24	Vectren Corporation	$58.03	6.76%	$1.68	3.09%	9.85%
25	Xcel Energy Inc.	$44.35	3.69%	$1.44	3.37%	7.05%
26	**Average**	**$61.68**	**4.74%**	**$1.99**	**3.41%**	**8.15%**
27	**Median**					**7.65%**

Sources:
[1] SNL Financial, Downloaded on May 24, 2017.
[2] Exhibit ICNU/209, page 1.
[3] *The Value Line Investment Survey*, March 17, April 28, and May 19, 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

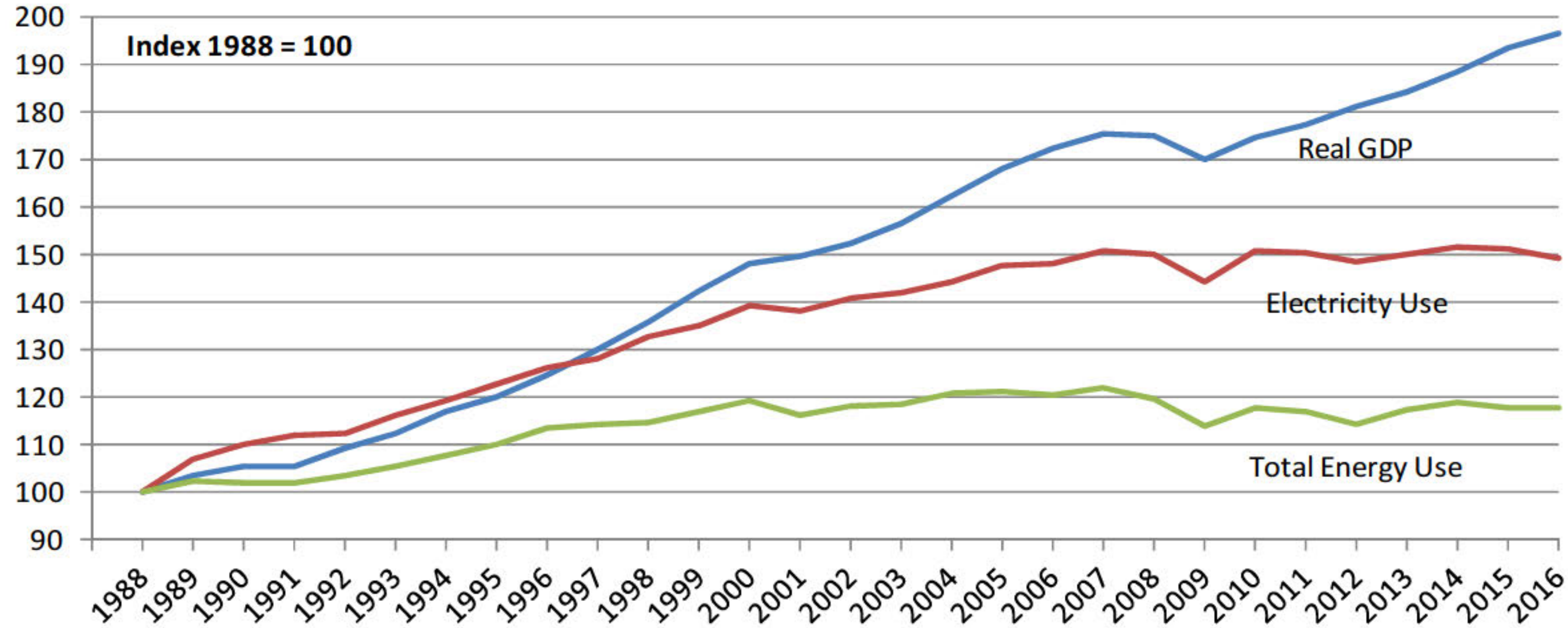
EXHIBIT ICNU/211

ELECTRICITY SALES ARE LINKED TO U.S. ECONOMIC GROWTH

June 16, 2017

Portland General Electric Company

Electricity Sales Are Linked to U.S. Economic Growth



Note:
1988 represents the base year. Graph depicts increases or decreases from the base year.

Sources:
U.S. Energy Information Administration
Federal Reserve Bank of St. Louis

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/212

MULTI-STAGE GROWTH DCF MODEL

June 16, 2017

Portland General Electric Company

Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1] (1)	Annualized Dividend[2] (2)	First Stage Growth[3] (3)	Second Stage Growth Year 6 (4)	Year 7 (5)	Year 8 (6)	Year 9 (7)	Year 10 (8)	Third Stage Growth[4] (9)	Multi-Stage Growth DCF (10)
1	ALLETE, Inc.	$68.09	$2.14	5.90%	5.62%	5.33%	5.05%	4.77%	4.48%	4.20%	7.85%
2	Alliant Energy Corporation	$39.46	$1.26	5.95%	5.66%	5.37%	5.08%	4.78%	4.49%	4.20%	7.92%
3	American Electric Power Company, Inc.	$67.11	$2.36	4.01%	4.04%	4.07%	4.11%	4.14%	4.17%	4.20%	7.82%
4	Ameren Corporation	$54.75	$1.76	6.28%	5.94%	5.59%	5.24%	4.89%	4.55%	4.20%	8.02%
5	CenterPoint Energy, Inc.	$27.66	$1.07	5.82%	5.55%	5.28%	5.01%	4.74%	4.47%	4.20%	8.67%
6	CMS Energy Corporation	$44.89	$1.33	6.87%	6.43%	5.98%	5.54%	5.09%	4.65%	4.20%	7.86%
7	Consolidated Edison, Inc.	$77.87	$2.76	3.75%	3.83%	3.90%	3.98%	4.05%	4.13%	4.20%	7.78%
8	Dominion Resources, Inc.	$77.18	$3.02	5.19%	5.02%	4.86%	4.69%	4.53%	4.36%	4.20%	8.54%
9	DTE Energy Company	$102.61	$3.30	5.40%	5.20%	5.00%	4.80%	4.60%	4.40%	4.20%	7.81%
10	Edison International	$79.40	$2.17	5.47%	5.26%	5.05%	4.84%	4.62%	4.41%	4.20%	7.28%
11	El Paso Electric Company	$50.03	$1.24	7.43%	6.89%	6.36%	5.82%	5.28%	4.74%	4.20%	7.37%
12	Entergy Corporation	$75.76	$3.48	6.00%	5.70%	5.40%	5.10%	4.80%	4.50%	4.20%	9.54%
13	IDACORP, Inc.	$83.12	$2.20	4.00%	4.03%	4.07%	4.10%	4.13%	4.17%	4.20%	6.91%
14	MGE Energy, Inc.	$63.95	$1.23	4.00%	4.03%	4.07%	4.10%	4.13%	4.17%	4.20%	N/A
15	OGE Energy Corp.	$35.25	$1.21	5.53%	5.31%	5.09%	4.87%	4.64%	4.42%	4.20%	8.09%
16	Otter Tail Corporation	$37.93	$1.28	5.60%	5.37%	5.13%	4.90%	4.67%	4.43%	4.20%	8.04%
17	PG&E Corporation	$66.50	$1.96	4.17%	4.18%	4.18%	4.19%	4.19%	4.20%	4.20%	7.26%
18	Pinnacle West Capital Corporation	$83.62	$2.62	5.56%	5.34%	5.11%	4.88%	4.65%	4.43%	4.20%	7.76%
19	Portland General Electric Company	$44.91	$1.28	5.07%	4.92%	4.78%	4.63%	4.49%	4.34%	4.20%	7.33%
20	PPL Corporation	$37.43	$1.58	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	4.20%	8.60%
21	Public Service Enterprise Group Incorporate	$44.49	$1.72	2.63%	2.89%	3.16%	3.42%	3.68%	3.94%	4.20%	7.84%
22	SCANA Corporation	$66.79	$2.45	5.43%	5.22%	5.02%	4.81%	4.61%	4.40%	4.20%	8.33%
23	Sempra Energy	$110.71	$3.29	8.86%	8.08%	7.30%	6.53%	5.75%	4.98%	4.20%	8.34%
24	Vectren Corporation	$58.03	$1.68	5.62%	5.39%	5.15%	4.91%	4.67%	4.44%	4.20%	7.50%
25	Xcel Energy Inc.	$44.35	$1.44	5.41%	5.21%	5.01%	4.81%	4.60%	4.40%	4.20%	7.85%
26	**Average**	**$61.68**	**$1.99**	**5.37%**	**5.17%**	**4.98%**	**4.78%**	**4.59%**	**4.39%**	**4.20%**	**7.93%**
27	**Median**										**7.85%**

Sources:
[1] SNL Financial, Downloaded on May 24, 2017.
[2] *The Value Line Investment Survey*, March 17, April 28, and May 19, 2017.
[3] Exhibit ICNU/206.
[4] *Blue Chip Financial Forecasts*, June 1, 2017 at 14.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

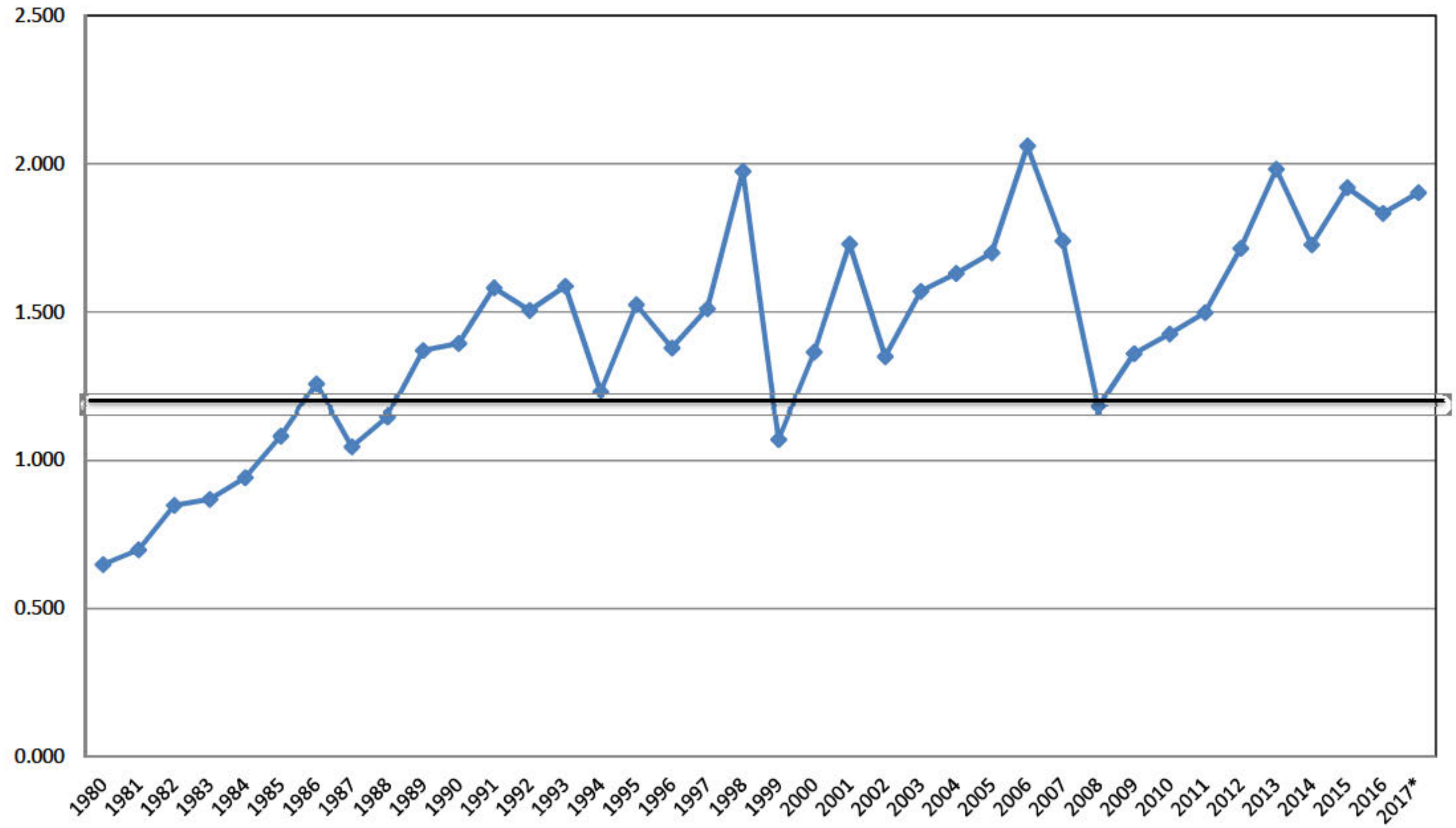
EXHIBIT ICNU/213

COMMON STOCK MARKET/BOOK RATIO

June 16, 2017

Portland General Electric Company

Common Stock Market/Book Ratio



Source:
1980 - 2000: Mergent Public Utility Manual.
2001 - 2015: AUS Utility Reports, multiple dates.
2016 - 2017: Value Line Investment Survey, multiple dates.
* Value Line Investment Survey Reports, February 17, March 3, March 17, and April 28, 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/214

EQUITY RISK PREMIUM – TREASURY BOND

June 16, 2017

Portland General Electric Company

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Electric Returns[1] (1)	30 yr. Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.93%	7.80%	6.13%		
2	1987	12.99%	8.58%	4.41%		
3	1988	12.79%	8.96%	3.83%		
4	1989	12.97%	8.45%	4.52%		
5	1990	12.70%	8.61%	4.09%	4.60%	
6	1991	12.55%	8.14%	4.41%	4.25%	
7	1992	12.09%	7.67%	4.42%	4.26%	
8	1993	11.41%	6.60%	4.81%	4.45%	
9	1994	11.34%	7.37%	3.97%	4.34%	
10	1995	11.55%	6.88%	4.67%	4.46%	4.53%
11	1996	11.39%	6.70%	4.69%	4.51%	4.38%
12	1997	11.40%	6.61%	4.79%	4.59%	4.42%
13	1998	11.66%	5.58%	6.08%	4.84%	4.65%
14	1999	10.77%	5.87%	4.90%	5.03%	4.68%
15	2000	11.43%	5.94%	5.49%	5.19%	4.82%
16	2001	11.09%	5.49%	5.60%	5.37%	4.94%
17	2002	11.16%	5.43%	5.73%	5.56%	5.07%
18	2003	10.97%	4.96%	6.01%	5.55%	5.19%
19	2004	10.75%	5.05%	5.70%	5.71%	5.37%
20	2005	10.54%	4.65%	5.89%	5.79%	5.49%
21	2006	10.34%	4.90%	5.44%	5.76%	5.56%
22	2007	10.31%	4.83%	5.48%	5.71%	5.63%
23	2008	10.37%	4.28%	6.09%	5.72%	5.63%
24	2009	10.52%	4.07%	6.45%	5.87%	5.79%
25	2010	10.29%	4.25%	6.04%	5.90%	5.84%
26	2011	10.19%	3.91%	6.28%	6.07%	5.91%
27	2012	10.01%	2.92%	7.09%	6.39%	6.05%
28	2013	9.81%	3.45%	6.36%	6.44%	6.08%
29	2014	9.75%	3.34%	6.41%	6.44%	6.15%
30	2015	9.60%	2.84%	6.76%	6.58%	6.24%
31	2016	9.60%	2.60%	7.00%	6.72%	6.40%
32	2017[3]	9.61%	3.04%	6.57%	6.62%	6.50%
33	**Average**	**11.12%**	**5.62%**	**5.50%**	**5.45%**	**5.45%**
34	**Minimum**				**4.25%**	**4.38%**
35	**Maximum**				**6.72%**	**6.50%**

Sources:

[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, January 1997 page 5, January 2011 page 3, and April 2017 page 6. 2006 - 2017 Auhorized Returns exclude limited issue rider cases.

[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/. The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.

[3] Data includes January - March 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/215

EQUITY RISK PREMIUM – UTILITY BOND

June 16, 2017

Portland General Electric Company

Equity Risk Premium - Utility Bond

Line	Year	Authorized Electric Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.93%	9.58%	4.35%		
2	1987	12.99%	10.10%	2.89%		
3	1988	12.79%	10.49%	2.30%		
4	1989	12.97%	9.77%	3.20%		
5	1990	12.70%	9.86%	2.84%	3.12%	
6	1991	12.55%	9.36%	3.19%	2.88%	
7	1992	12.09%	8.69%	3.40%	2.99%	
8	1993	11.41%	7.59%	3.82%	3.29%	
9	1994	11.34%	8.31%	3.03%	3.26%	
10	1995	11.55%	7.89%	3.66%	3.42%	3.27%
11	1996	11.39%	7.75%	3.64%	3.51%	3.20%
12	1997	11.40%	7.60%	3.80%	3.59%	3.29%
13	1998	11.66%	7.04%	4.62%	3.75%	3.52%
14	1999	10.77%	7.62%	3.15%	3.77%	3.52%
15	2000	11.43%	8.24%	3.19%	3.68%	3.55%
16	2001	11.09%	7.76%	3.33%	3.62%	3.56%
17	2002	11.16%	7.37%	3.79%	3.61%	3.60%
18	2003	10.97%	6.58%	4.39%	3.57%	3.66%
19	2004	10.75%	6.16%	4.59%	3.86%	3.82%
20	2005	10.54%	5.65%	4.89%	4.20%	3.94%
21	2006	10.34%	6.07%	4.27%	4.39%	4.00%
22	2007	10.31%	6.07%	4.24%	4.48%	4.04%
23	2008	10.37%	6.53%	3.84%	4.37%	3.97%
24	2009	10.52%	6.04%	4.48%	4.34%	4.10%
25	2010	10.29%	5.46%	4.83%	4.33%	4.26%
26	2011	10.19%	5.04%	5.15%	4.51%	4.45%
27	2012	10.01%	4.13%	5.88%	4.84%	4.66%
28	2013	9.81%	4.48%	5.33%	5.13%	4.75%
29	2014	9.75%	4.28%	5.47%	5.33%	4.84%
30	2015	9.60%	4.12%	5.48%	5.46%	4.90%
31	2016	9.60%	3.93%	5.67%	5.57%	5.04%
32	2017 [3]	9.61%	4.18%	5.43%	5.48%	5.16%
33	**Average**	**11.12%**	**6.99%**	**4.13%**	**4.08%**	**4.05%**
34	**Minimum**				**2.88%**	**3.20%**
35	**Maximum**				**5.57%**	**5.16%**

Sources:

[1] *Regulatory Research Associates, Inc* ., Regulatory Focus, Major Rate Case Decisions, January 1997 page 5, January 2011 page 3, and April 2017 page 6.
2006 - 2017 Auhorized Returns exclude limited issue rider cases.

[2] Mergent Public Utility Manual, Mergent Weekly News Reports, 2003. The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record. The utility yields from 2010-2017 were obtained from http://credittrends.moodys.com/.

[3] Data includes January - March 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/216

BOND YIELD SPREADS

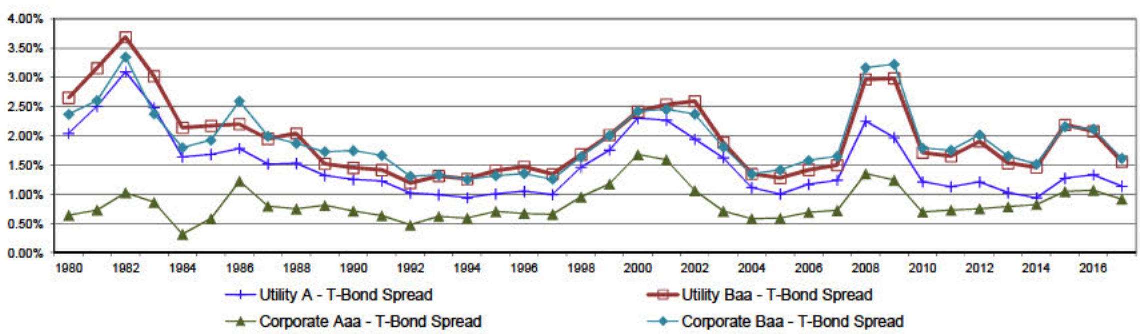
June 16, 2017

Portland General Electric Company

Bond Yield Spreads

			Public Utility Bond				Corporate Bond				Utility to Corporate	
Line	Year	T-Bond Yield[1] (1)	A[2] (2)	Baa[2] (3)	A-T-Bond Spread (4)	Baa-T-Bond Spread (5)	Aaa[3] (6)	Baa[3] (7)	Aaa-T-Bond Spread (8)	Baa-T-Bond Spread (9)	Baa Spread (10)	A-Aaa Spread (11)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%	1.40%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%	1.78%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%	2.07%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%	1.62%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%	1.32%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%	1.10%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%	0.56%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%	0.72%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%	0.78%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%	0.51%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.30%	0.54%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%	0.59%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%	0.55%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%	0.37%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%	0.35%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%	0.30%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%	0.38%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%	0.34%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%	0.51%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%	0.58%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%	0.62%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%	0.68%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%	0.88%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%	0.91%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%	0.53%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%	0.41%
27	2006	4.90%	6.07%	6.32%	1.17%	1.42%	5.59%	6.48%	0.69%	1.58%	-0.16%	0.48%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%	0.52%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%	0.90%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%	0.73%
31	2010	4.25%	5.46%	5.96%	1.21%	1.71%	4.95%	6.04%	0.70%	1.79%	-0.08%	0.52%
32	2011	3.91%	5.04%	5.56%	1.13%	1.65%	4.64%	5.67%	0.73%	1.76%	-0.10%	0.40%
33	2012	2.92%	4.13%	4.83%	1.21%	1.90%	3.67%	4.94%	0.75%	2.02%	-0.11%	0.46%
34	2013	3.45%	4.48%	4.98%	1.03%	1.53%	4.24%	5.10%	0.79%	1.65%	-0.12%	0.24%
35	2014	3.34%	4.28%	4.80%	0.94%	1.46%	4.16%	4.86%	0.82%	1.52%	-0.06%	0.12%
36	2015	2.84%	4.12%	5.03%	1.27%	2.19%	3.89%	5.00%	1.05%	2.16%	0.03%	0.23%
37	2016	2.60%	3.93%	4.67%	1.33%	2.08%	3.66%	4.71%	1.07%	2.12%	-0.04%	0.27%
38	2017[4]	3.04%	4.18%	4.60%	1.14%	1.56%	3.96%	4.66%	0.92%	1.62%	-0.06%	0.22%
39	**Average**	**6.62%**	**8.13%**	**8.57%**	**1.51%**	**1.95%**	**7.46%**	**8.56%**	**0.84%**	**1.94%**	**0.01%**	**0.67%**

Yield Spreads
Treasury Vs. Corporate & Treasury Vs. Utility



Sources:

[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.

[2] The utility yields for the period 1980-2000 were obtained from Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record.
The utility yields for the period 2010-2017 were obtained from http://credittrends.moodys.com/.

[3] The corporate yields for the period 1980-2009 were obtained from the St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The corporate yields from 2010-2017 were obtained from http://credittrends.moodys.com/.

[4] Data includes January - March 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/217

TREASURY AND UTILITY BOND YIELDS

June 16, 2017

Portland General Electric Company

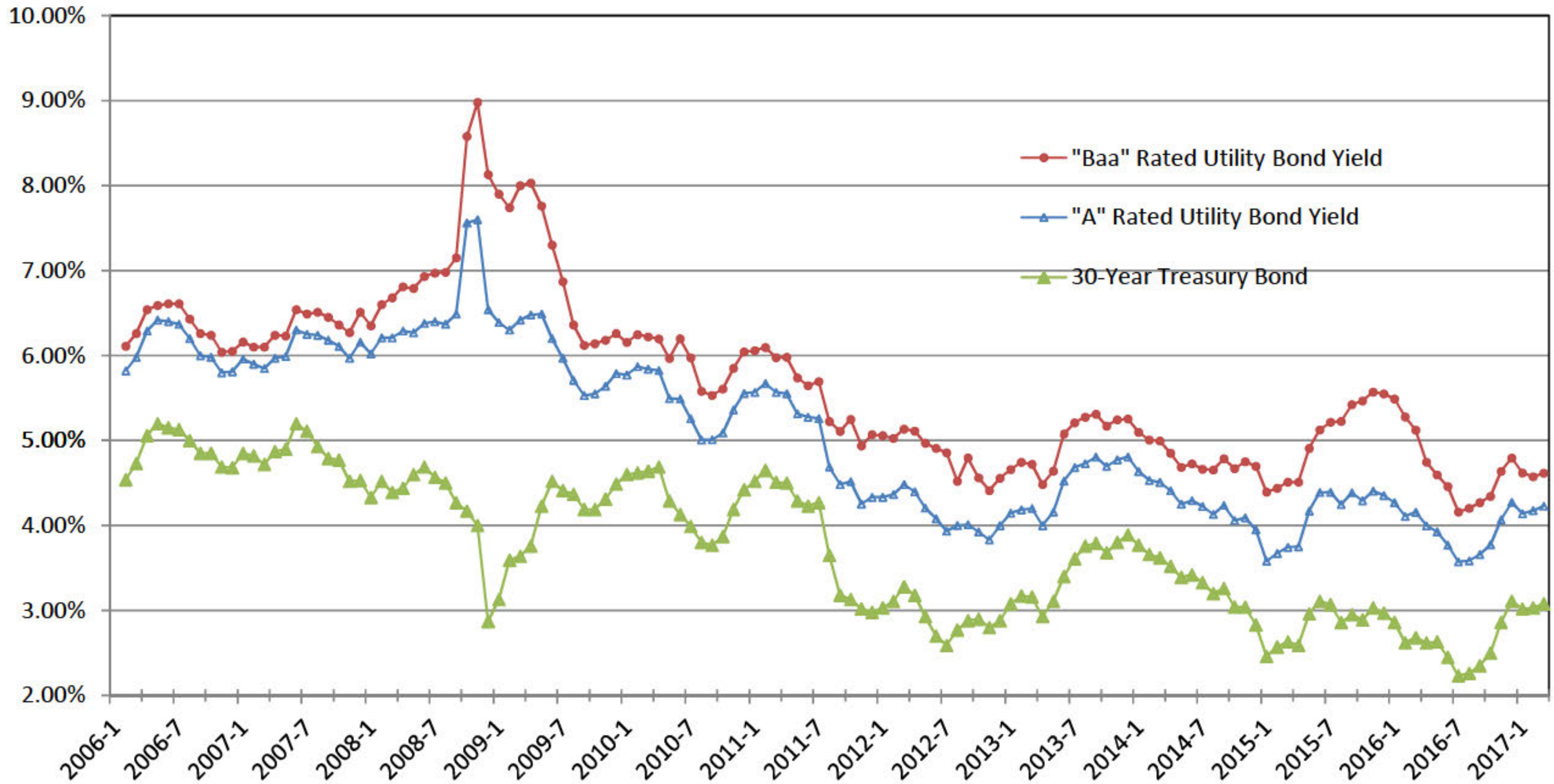
Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	05/19/17	2.90%	4.06%	4.44%
2	05/12/17	2.98%	4.15%	4.54%
3	05/05/17	2.99%	4.16%	4.54%
4	04/28/17	2.96%	4.13%	4.51%
5	04/21/17	2.89%	4.08%	4.47%
6	04/13/17	2.89%	4.06%	4.46%
7	04/07/17	3.00%	4.17%	4.57%
8	03/31/17	3.02%	4.18%	4.58%
9	03/24/17	3.00%	4.16%	4.55%
10	03/17/17	3.11%	4.26%	4.65%
11	03/10/17	3.16%	4.31%	4.69%
12	03/03/17	3.08%	4.22%	4.60%
13	02/24/17	2.95%	4.10%	4.48%
14	**Average**	**2.99%**	**4.16%**	**4.54%**
15	**Spread To Treasury**		**1.17%**	**1.55%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] http://credittrends.moodys.com/.

Portland General Electric Company

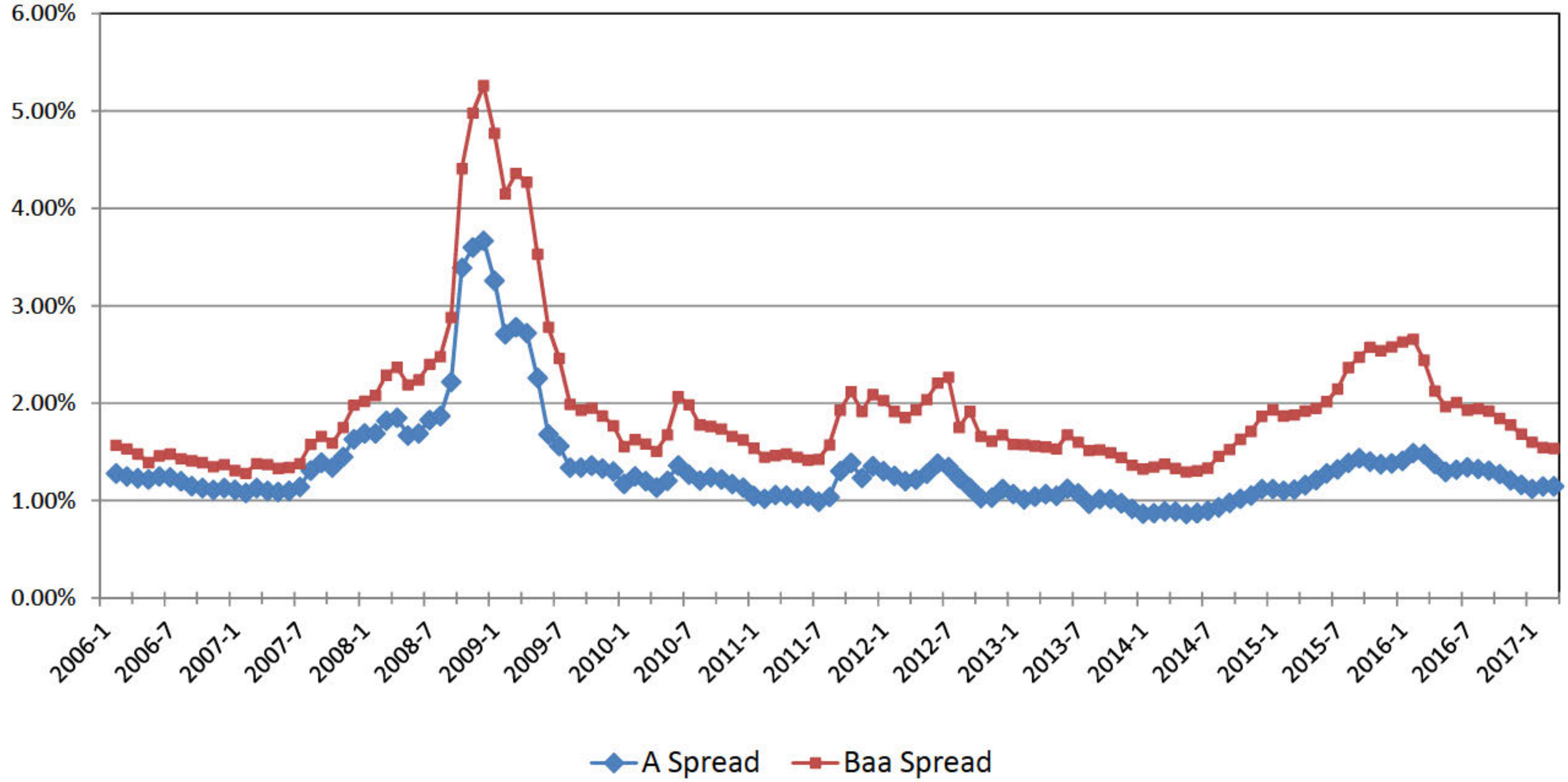
Trends in Bond Yields



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Portland General Electric Company

Yield Spread Between Utility Bonds and 30-Year Treasury Bonds



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/218

VALUE LINE BETA

June 16, 2017

Portland General Electric Company

Value Line Beta

Line	Company	Beta
1	ALLETE, Inc.	0.80
2	Alliant Energy Corporation	0.70
3	American Electric Power Company, Inc.	0.65
4	Ameren Corporation	0.70
5	CenterPoint Energy, Inc.	0.85
6	CMS Energy Corporation	0.65
7	Consolidated Edison, Inc.	0.50
8	Dominion Resources, Inc.	0.65
9	DTE Energy Company	0.65
10	Edison International	0.60
11	El Paso Electric Company	0.75
12	Entergy Corporation	0.65
13	IDACORP, Inc.	0.75
14	MGE Energy, Inc.	0.70
15	OGE Energy Corp.	0.95
16	Otter Tail Corporation	0.85
17	PG&E Corporation	0.65
18	Pinnacle West Capital Corporation	0.70
19	Portland General Electric Company	0.70
20	PPL Corporation	0.70
21	Public Service Enterprise Group Incorporated	0.65
22	SCANA Corporation	0.65
23	Sempra Energy	0.80
24	Vectren Corporation	0.75
25	Xcel Energy Inc.	0.60
26	**Average**	**0.70**

Source:
The Value Line Investment Survey,
March 17, April 28, and May 19, 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/219

CAPM RETURN

June 16, 2017

Portland General Electric Company

CAPM Return

Line	Description	High Market Risk Premium (1)	Low Market Risk Premium (2)
1	Risk-Free Rate[1]	3.70%	3.70%
2	Risk Premium[2]	7.80%	6.00%
3	Beta[3]	0.70	0.70
4	**CAPM**	**9.19%**	**7.92%**

Sources:

[1] *Blue Chip Financial Forecasts*; June 1, 2017, at 2.

[2] *Duff & Phelps, 2017 SBBI Yearbook* at 6-17 and 6-18, and *Duff & Phelps, 2017 Valuation Handbook* at 3-36 and 3-48.

[3] Exhibit ICNU/218.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/220

STANDARD & POOR'S CREDIT METRICS

June 16, 2017

Portland General Electric Company

Standard & Poor's Credit Metrics

Line	Description	Retail Cost of Service Amount ($000)	S&P Benchmark (Medial Volatility)[1/2] Intermediate	Significant	Aggressive	Reference
		(1)	(2)	(3)	(4)	(5)
1	Rate Base	$ 4,594,052				PGE Exhibit / 201.
2	Weighted Common Return	4.50%				Page 2, Line 2, Col. 4.
3	Pre-Tax Rate of Return	10.40%				Page 2, Line 3, Col. 5.
4	Income to Common	$ 206,757				Line 1 x Line 2.
5	EBIT	$ 477,848				Line 1 x Line 3.
6	Depreciation & Amortization	$ 377,278				PGE Exhibit / 201.
7	Imputed Amortization	$ 20,721				S&P Capital IQ, downloaded on June 6, 2017.
8	Deferred Income Taxes & ITC	$ 18,301				PGE Exhibit / 201.
9	Funds from Operations (FFO)	$ 623,057				Sum of Line 4 and Lines 6 through 8.
10	Imputed Interest Expense	$ 36,583				S&P Capital IQ, downloaded on June 6, 2017.
11	EBITDA	$ 912,430				Sum of Lines 5 through 7 and Line 10.
12	Total Debt Ratio	55%				Page 3, Line 3, Col. 2.
13	Debt to EBITDA	2.8x	2.5x - 3.5x	3.5x - 4.5x	4.5x - 5.5x	(Line 1 x Line 12) / Line 11.
14	FFO to Total Debt	25%	23% - 35%	13% - 23%	9% - 13%	Line 9 / (Line 1 x Line 12).

Sources:
[1] Standard & Poor's RatingsDirect: "Criteria: Corporate Methodology," November 19, 2013.
[2] Standard & Poor's RatingsDirect: "Portland General Electric Co." April 7, 2017.

Note:
Based on the April 2017 S&P report, PGE has a "Strong" business risk profile and a "Significant" financial risk profile, and falls under the "Medial Volatility" matrix.

Portland General Electric Company

Standard & Poor's Credit Metrics
(Pre-Tax Rate of Return)

Line	Description	Amount (000) (1)	Weight (2)	Cost (3)	Weighted Cost (4)	Pre-Tax Weighted Cost (5)
1	Long-Term Debt	$ 2,661,400	51.35%	5.17%	2.65%	2.65%
2	Common Equity	2,521,922	48.65%	**9.25%**	4.50%	7.75%
3	**Total**	**$ 5,183,322**	**100.00%**		**7.16%**	**10.40%**
4	Tax Conversion Factor*					1.7213

Sources:
Exhibit ICNU / 202.
* Exhibit PGE / 201.

Portland General Electric Company

Standard & Poor's Credit Metrics
(Financial Capital Structure)

Line	Description	Amount (000) (1)	Weight (2)
1	Long-Term Debt	$ 2,661,400	47.52%
2	Off Balance Sheet Debt*	417,493	7.45%
3	**Total Debt**	**$ 3,078,893**	54.97%
4	Common Equity	$ 2,521,922	45.03%
5	**Total**	**$ 5,600,815**	**100.00%**

Source:
*S&P Capital IQ, downloaded on June 6, 2017.

Portland General Electric Company

S&P Adjusted Debt Ratio
(Operating Subsidiaries)

13 Quarter Average

Line	Rating	Count	Average	Median	High	Low	% Distribution of Quarterly Average < 50	50 to 55	> 55
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	AA-	1	42.58	42.58	42.58	42.58	100%	0%	0%
2	A	7	49.08	50.02	52.31	39.77	43%	57%	0%
3	A-	44	51.44	52.40	63.90	39.36	34%	41%	25%
4	BBB+	23	52.01	52.24	60.33	37.53	26%	39%	35%
5	BBB	8	52.70	53.18	57.03	47.22	25%	38%	38%
6	BBB-	10	55.29	54.86	59.62	50.66	0%	50%	50%
7	BB	0			-	-			
8	**Total**	**93**							
9	**Average**		**50.51**	**50.88**	**47.97**	**36.73**			

Quarter Results - 2013Q4 through 2016Q4

Line	Rating	Count	Average	Median	High	Low	% Distribution of Quarterly Average < 50	50 to 55	> 55
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
10	AA-	12	42.58	42.70	44.98	40.78	100%	0%	0%
11	A	75	50.35	50.67	57.10	38.99	40%	55%	5%
12	A-	525	51.46	52.39	64.53	31.05	38%	34%	28%
13	BBB+	289	52.17	52.53	61.78	35.62	27%	42%	31%
14	BBB	101	52.71	53.00	60.01	44.64	30%	39%	32%
15	BBB-	125	55.28	54.56	67.82	41.38	10%	42%	48%
16	BB	-	-	-	-	-			
17	**Total**	**1127**							
18	**Average**		**50.76**	**50.98**	**50.89**	**33.21**			

Source:
Standard and Poor's Global Credit Portal, downloaded June 1, 2017.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT ICNU/221

ACCURACY OF INTEREST RATE FORECASTS

June 16, 2017

Portland General Electric Company

Accuracy of Interest Rate Forecasts
(Long-Term Treasury Bond Yields - Projected Vs. Actual)

		Publication Data				
Line	Date	Prior Quarter Actual Yield (1)	Projected Yield (2)	Projected Quarter (3)	Actual Yield in Projected Quarter (4)	Projected Yield Higher (Lower) Than Actual Yield* (5)
1	Dec-00	5.8%	5.8%	1Q, 02	5.6%	0.2%
2	Mar-01	5.7%	5.6%	2Q, 02	5.8%	-0.2%
3	Jun-01	5.4%	5.8%	3Q, 02	5.2%	0.6%
4	Sep-01	5.7%	5.9%	4Q, 02	5.1%	0.8%
5	Dec-01	5.5%	5.7%	1Q, 03	5.0%	0.7%
6	Mar-02	5.3%	5.9%	2Q, 03	4.7%	1.2%
7	Jun-02	5.6%	6.2%	3Q, 03	5.2%	1.0%
8	Sep-02	5.8%	5.9%	4Q, 03	5.2%	0.7%
9	Dec-02	5.2%	5.7%	1Q, 04	4.9%	0.8%
10	Mar-03	5.1%	5.7%	2Q, 04	5.4%	0.3%
11	Jun-03	5.0%	5.4%	3Q, 04	5.1%	0.3%
12	Sep-03	4.7%	5.8%	4Q, 04	4.9%	0.9%
13	Dec-03	5.2%	5.9%	1Q, 05	4.8%	1.1%
14	Mar-04	5.2%	5.9%	2Q, 05	4.6%	1.4%
15	Jun-04	4.9%	6.2%	3Q, 05	4.5%	1.7%
16	Sep-04	5.4%	6.0%	4Q, 05	4.8%	1.2%
17	Dec-04	5.1%	5.8%	1Q, 06	4.6%	1.2%
18	Mar-05	4.9%	5.6%	2Q, 06	5.1%	0.5%
19	Jun-05	4.8%	5.5%	3Q, 06	5.0%	0.5%
20	Sep-05	4.6%	5.2%	4Q, 06	4.7%	0.5%
21	Dec-05	4.5%	5.3%	1Q, 07	4.8%	0.5%
22	Mar-06	4.8%	5.1%	2Q, 07	5.0%	0.1%
23	Jun-06	4.6%	5.3%	3Q, 07	4.9%	0.4%
24	Sep-06	5.1%	5.2%	4Q, 07	4.6%	0.6%
25	Dec-06	5.0%	5.0%	1Q, 08	4.4%	0.6%
26	Mar-07	4.7%	5.1%	2Q, 08	4.6%	0.5%
27	Jun-07	4.8%	5.1%	3Q, 08	4.5%	0.7%
28	Sep-07	5.0%	5.2%	4Q, 08	3.7%	1.5%
29	Dec-07	4.9%	4.8%	1Q, 09	3.5%	1.4%
30	Mar-08	4.6%	4.8%	2Q, 09	4.0%	0.8%
31	Jun-08	4.4%	4.9%	3Q, 09	4.3%	0.6%
32	Sep-08	4.6%	5.1%	4Q, 09	4.3%	0.8%
33	Dec-08	4.5%	4.6%	1Q, 10	4.6%	0.0%
34	Mar-09	3.7%	4.1%	2Q, 10	4.4%	-0.3%
35	Jun-09	3.5%	4.6%	3Q, 10	3.9%	0.8%
36	Sep-09	4.0%	5.0%	4Q, 10	4.2%	0.8%
37	Dec-09	4.3%	5.0%	1Q, 11	4.6%	0.4%
38	Mar-10	4.3%	5.2%	2Q, 11	4.3%	0.9%
39	Jun-10	4.6%	5.2%	3Q, 11	3.7%	1.5%
40	Sep-10	4.4%	4.7%	4Q, 11	3.0%	1.7%
41	Dec-10	3.9%	4.6%	1Q, 12	3.1%	1.5%
42	Mar-11	4.2%	5.1%	2Q, 12	2.9%	2.2%
43	Jun-11	4.6%	5.2%	3Q, 12	2.8%	2.5%
44	Sep-11	4.3%	4.2%	4Q, 12	2.9%	1.3%
45	Dec-11	3.7%	3.8%	1Q, 13	3.1%	0.7%
46	Mar-12	3.0%	3.8%	2Q, 13	3.2%	0.7%
47	Jun-12	3.1%	3.7%	3Q, 13	3.7%	0.0%
48	Sep-12	2.9%	3.4%	4Q, 13	3.8%	-0.4%
49	Dec-12	2.8%	3.4%	1Q, 14	3.7%	-0.3%
50	Mar-13	2.9%	3.6%	2Q, 14	3.4%	0.2%
51	Jun-13	3.1%	3.7%	3Q, 14	3.3%	0.4%
52	Sep-13	3.2%	4.2%	4Q, 14	3.0%	1.2%
53	Dec-13	3.7%	4.2%	1Q, 15	2.6%	1.7%
54	Mar-14	3.8%	4.4%	2Q 15	2.9%	1.5%
55	Jun-14	3.7%	4.3%	3Q 15	2.8%	1.5%
56	Sep-14	3.4%	4.3%	4Q 15	3.0%	1.3%
57	Dec-14	3.3%	4.0%	1Q 16	2.7%	1.3%
58	Mar-15	3.0%	3.7%	2Q 16	2.6%	1.1%
59	Jun-15	2.6%	3.7%	3Q 16	2.3%	1.4%
60	Sep-15	2.9%	3.8%	4Q 16	2.8%	1.0%
61	Dec-15	2.8%	3.7%	1Q 17	3.0%	0.7%
62	Jan-16	3.0%	3.8%	2Q 17		
63	Feb-16	3.0%	3.7%	2Q 17		
64	Mar-16	3.0%	3.5%	2Q 17		
65	Apr-16	2.7%	3.6%	3Q 17		
66	May-16	2.7%	3.5%	3Q 17		
67	Jun-16	2.7%	3.4%	3Q 17		
68	Jul-16	2.7%	3.4%	4Q 17		
69	Aug-16	2.6%	3.1%	4Q 17		
70	Sep-16	2.6%	3.1%	4Q 17		
71	Oct-16	2.3%	3.1%	1Q 18		
72	Nov-16	2.3%	3.1%	1Q 18		
73	Dec-16	2.3%	3.4%	1Q 18		
74	Jan-17	2.8%	3.7%	2Q 18		
75	Feb-17	2.8%	3.7%	2Q 18		
76	Mar-17	2.8%	3.7%	2Q 18		
77	Apr-17	3.1%	3.8%	3Q 18		
78	May-17	3.0%	3.7%	3Q 18		
79	Jun-17	3.0%	3.7%	3Q 18		

Source:
Blue Chip Financial Forecasts, Various Dates.
* Col. 2 - Col. 4.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 319

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

CONFIDENTIAL OPENING GENERAL RATE CASE TESTIMONY
OF BRADLEY G. MULLINS

ON BEHALF OF THE
INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

(REDACTED VERSION)

June 16, 2017

**TABLE OF CONTENTS TO
THE OPENING RATE CASE TESTIMONY OF BRADLEY G. MULLINS**

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

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

A. I am an independent consultant representing energy and utility customers in jurisdictions around the United States and am appearing in this matter—the 2018 General Rate Case ("GRC") filing of Portland General Electric Company (the "Company")—on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large customers of electric utilities located throughout the Pacific Northwest, including customers of the Company.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. A summary of my education and work experience can be found at ICNU/100 and a list of my regulatory appearances can be found in ICNU/101.

Q. WHAT IS THE PURPOSE OF YOUR OPENING TESTIMONY?

A. Pursuant to the Prehearing Conference Memorandum issued by Administrative Law Judges Tracy A.G. Kirkpatrick and Ruth Harper on March 15, 2017, this matter was bifurcated into separate procedural schedules for general rate case and net variable power cost issues. This testimony addresses issues pertinent to the general rate case portion of this proceeding. Specifically, I address the $99.9 million revenue increase that the Company proposes in this matter.[1/] I also address the Company's calculation of load following costs in the generation

[1/] Exh. No. PGE/200, Workpaper "Exhibit Support 2018" marginal cost study. In addition to my testimony, Mr. Michael Gorman is providing testimony on behalf of ICNU supporting a 9.25% return on equity, which has been incorporated into my recommendations below.

Q. WHAT WAS THE NATURE OF YOUR REVIEW OF THE COMPANY'S FILING.

A. I reviewed the Company's testimony, exhibits, and electronic workpapers. I have also issued many data requests, and have reviewed the Company's responses to those requests, as well as the Company's responses to many of the requests issued by other parties in this proceeding.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Unlike in prior rate cases which have involved the addition of discrete large capital projects, the Company's request in this matter is driven, almost entirely, by the use of a forward-looking budget. Establishment of budgets, however, is based largely on the exercise of discretion on the part of the Company. For external parties and the Commission to have a reasonable ability to validate the budgetary assumptions the Company proposes, the Company must explain and justify the differences between the budgeted expenditures and actual expenditures incurred in the historic period. In this case, I have not found such a connection. For this reason, I recommend that the Commission reject the Company's filing because it fails to adequately demonstrate the need for a rate increase.

If the Commission does not reject the filing, however, I recommend that it require the Company to refile its case based either on an historical test year or a combined historical/future test year so that parties and the Commission can better verify the Company's costs and revenues that drive its requested revenue requirement in this case.

Finally, if the Commission allows the Company to proceed with establishing its revenue requirement based on a future test year, it is important for the Commission to recognize that there is a great deal of judgement and discretion involved in establishing the budgets, and for that reason, the Commission may appropriately exercise similar discretion and judgement when determining the ultimate budget used to set rates in this matter.

With that concept in mind, I have developed several recommended adjustments to the Company's revenue requirement proposal. These adjustments have been summarized in Table 1, below, and are described in greater detail in the testimony sections that follow. A supplemental schedule supporting the adjustment calculations is provided in Exhibit No. ICNU/301.

TABLE 1
Revenue Requirement Adjustments
($000)

Ln. No.	Adj. No.	Description	Rate Base	Net Oper. Income	Rev. Req. Def. /(Suf.)
1		**Company Request**	**4,594,053**	**405,856**	**99,897**
		Proposed Adjustments			
2	IN-1	Cost of Capital (Gorman)	-	-	(24,098)
3	IN-2	State Tax Rate	-	-	(162)
4	IN-3	Budgeted Staffing and Capital Levels	(84,325)	3,010	(15,533)
5	IN-4	Depreciation Expenses	-	21,739	(37,340)
6	IN-5	Medical Benefits Expense	-	4,329	(7,435)
7	IN-6	Other Revenues	-	96	(165)
8	IN-7	ADIT - Production Tax Credit Carryforward	(60,019)	-	(7,376)
9	IN-8	ADIT - Minimum Tax Credit Carryforward	(7,239)	-	(890)
10	IN-9	ADIT - Deferred Broker Settlements	(4,666)	-	(573)
11	IN-10	ADIT - Accrued Incentives	(3,516)	-	(432)
12	IN-11	ADIT - Stock Incentive Plan	(4,487)	-	(551)
13	IN-12	ADIT - Accrued Vacation	(6,784)	-	(834)
14	IN-13	ADIT - Boardman Biomass Revenues	(1,103)	-	(136)
15	IN-14	Interest Synchronization	-	(928)	1,594
16		**Total Adjustments**	**(172,139)**	**28,246**	**(93,933)**
17		**ICNU Proposed**	**4,421,914**	**434,102**	**5,965**

In addition to the above revenue requirement adjustments, I also have some concerns with the rate spread methodology the Company has proposed related to the customer impact offset and load following. I propose using the existing load following credit allocation methodology, as used in the Company's 2015 and 2016 general rate cases ("GRC"), as it will serve to better mitigate the customer impacts of the Company's proposed rate increase than the methodologies the Company proposes in this matter.

II. USE OF BUDGETED EXPENDITURES

Q. WHAT IS YOUR CONCERN WITH THE WAY THAT THE COMPANY HAS USED BUDGETED EXPENDITURES IN THIS MATTER?

A. The use of budgets plays a key role in the Company's rate filing. In fact, the entirety of the Company's revenue requirement request in this matter can be attributed to the use of budget assumptions.[2/] The problem with the use of these budgets, however, is that they are difficult, if not impossible, to independently verify.

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

A. In Oregon, there are no specific statutes or regulations specifying the appropriate test year to be used in a utility rate filing. In fact, the Company appears to have used some form of a future test year, relying in part on budgeted expenditures, for ratemaking purposes since at least 1974.[3/] Nevertheless, I am not aware that the Commission has ever expressly required the Company to use a future test year, or even endorsed the Company's decision to do so in every general rate case. Indeed, the Commission has previously recognized that it has allowed

---

2/ See Exh. No. ICNU/302 at 8 (the $153.0 million total budgeted increase exceeds the $99.9 million rate increase the Company seeks in this matter).

3/ See American Can Co. v. Lobdell, 55 Or.App 451, 462, 638 P.2d 1152, 1159 (1982) utilities to use future test years, historical test years, or a combination of the two,[4/] and when it did affirmatively endorse the Company's use of a future test year, it did so recognizing that the Company "will undergo major expense changes which will not be felt until the second half of [the test year], and setting rates for the future cannot be accomplished in any equitable manner without considering the expenses."[5/] By contrast, the Company in this case has not identified any major expense that is driving its case and must occur late in the test year.

Q. IS THIS CASE DIFFERENT FROM PREVIOUS RATE CASES?

A. Yes. In the Company's previous rate cases, the rate increases were driven by large new capital investments, such as new generation facilities. So long as the Company could establish the prudence of these investments, the rate increases were largely the result of known and measurable costs. By contrast, this rate case contains no similar known and measurable investments and is driven primarily by the Company's claims to need additional personnel.

Q. REGARDLESS OF WHETHER THE COMPANY USES A FUTURE OR HISTORICAL TEST YEAR, DOES THIS CHANGE ITS BURDEN OF PROOF?

A. No. The Company still bears the burden of proof to demonstrate the reasonableness of the budgeted expenditures it proposes. For that reason, I believe that the utility also has an obligation to explain any differences between budgeted expenditures as compared to actual results in the historical period. Given the magnitude of the difference between the budgeted expenditures the Company proposes relative to the amounts actually incurred in 2016, however, I am concerned with the lack of clear explanation for the changes.

4/ In the Matter of the Revised Tariff Schedules Applicable to Electric Service, OPUC Docket UE 111, Order No. 00-091 at 2-3 (Feb. 14, 2000) (citing In the Matter of the Application of U S WEST Communications, Inc., for an Increase in Revenues, Order No. 97-171 (noting that the Commission used a combination of historical and future data for the test year)); see OAR 860-022-0019(1)(d), renumbered from OAR 860-013-0075.

5/ Re Portland Gen. Elec. Co., 1974 WL 391914 (Or.P.U.C.), 8 P.U.R.4th 393, 399–400 (Dec. 23, 1974).

Q. WHAT IS YOUR PRIMARY RECOMMENDATION IN THIS PROCEEDING?

A. I recommend that the Commission reject the Company's application on the basis that the Company has not met its burden to demonstrate the need for a rate increase based on known and measurable costs. I would note that this would not be an unprecedented decision. The Washington Utilities and Transportation Commission recently rejected an application for a rate increase from Avista Corp. on the basis that the utility had failed to justify the need for higher rates.[6/]

Q. HAVE YOU ATTEMPTED TO REVIEW THE BUDGET LEVELS PROPOSED BY THE COMPANY?

A. Yes. In the event the Commission does not reject the Company's filing, I performed a comparison between the budgeted expenditures the Company proposed in 2018 and the actual expenditures the Company incurred in 2016. This analysis can be found in Exhibit ICNU/302. With respect to operations and maintenance ("O&M") expenses, the Company has proposed an approximate $71.9 million increase, relative to 2016 levels.[7] In addition, the Company has proposed a material increase to rate base based on its budgeted capital expenditures through the end of 2017. Given the Company's flat load, the Company has no need for rate relief in this matter absent the budgeted increases. Thus, in my opinion, the Commission would appropriately exercise a wide degree of latitude in establishing the final rate increase approved in this matter.

6/ WUTC v. Avista Corp., WUTC Docket No. UE-160228/UG-160229, Order 06 (Dec. 15, 2016).
7/ Exh. No. ICNU/302 at 8 (sum of lines "Admin_&_Other Total" and "Production_&_Distrib Total")

Q. HOW DOES THE COMPANY DEVELOP ITS BUDGET?

A. In ICNU data request ("DR") 031,[8/] the Company was requested to provide a narrative explanation of the methodologies it employed to develop its budget for the rate year, along with any documents containing formalized policies and procedures surrounding the budgeting process.

As I understand the Company's response, department managers are generally responsible for developing the budgets for their departments. The budgets developed at the department level are then subject to a review process, and ultimate consideration by the board of directors.

Q. WHAT FACTORS DO DEPARTMENT MANAGERS TAKE INTO CONSIDERATION WHEN DEVELOPING THE BUDGET FOR THEIR DEPARTMENT?

A. It's not clear. In Attachment 031-B to the Company's response to ICNU DR 031, the Company provided its 2017 Budget Instruction Manual. That document goes to great length describing the budgeting process itself. It does not, however, contain much in the way of guidance as to the things that a manager considers when developing the budget other than the Company's "larger corporate objectives," the budget objective "to translate the resource requirements for each activity the department performs into accounting terms," and a general list of items that each department is responsible for.[9/]

Q. DO DEPARTMENT MANAGERS EXERCISE DISCRETION AND JUDGEMENT WHEN ESTABLISHING A BUDGET?

A. Yes. As the Commission probably knows through the establishment of its own budgets, there is a great deal of discretion and judgement involved in establishing a budget. When working

---

8/ Exh. No. ICNU/303 at 10-11

9/ PGE 2017 Budget Instruction Manual at 6, 14-26.

within a limited budget, sometimes it is necessary to make decisions to prioritize expenditures. As I have reviewed the Company filing, the Company has not demonstrated whether its budgets appropriately prioritize its expenditures, in the same way that the Commission must prioritize its expenditures based on the limited set of funds available to it.

Q. IS IT POSSIBLE TO INDEPENDENTLY VERIFY WHETHER THE BUDGET FOR ANY PARTICULAR DEPARTMENT IS REASONABLE?

A. Since a budget is based largely on subjective judgements and assumptions of individuals throughout the Company, it is generally difficult to independently validate budget assumptions used by mangers, except at relatively high levels. For example, if a department manager has requested additional employees based on heightened workload, there are not many ways for an external auditor to review whether the workload in the department truly is too high, other than actually spending time working in the department.

Q. WHY IS IT PROBLEMATIC THAT THE BUDGETS ARE DIFFICULT TO INDEPENDENTLY VERIFY?

A. This raises concerns that the Company's projected expenditures are not known and measurable. If the Commission approves rates based on budgeted estimates, the Company can plan its operations to meet its budgets rather than operating based on known and measurable historical costs.

Q. DO RATEPAYERS HAVE THE SAME INCENTIVES AS SHAREHOLDERS, WITH RESPECT TO THE ESTABLISHMENT OF BUDGETS?

A. No. It has long been documented that utilities subject to rate of return regulation have an incentive to over-invest in capital in order to increase earnings. In 1962, for example, Harvey Averch and Leland Johnson authored a paper hypothesizing that a regulated firm has an incentive to acquire an excessive amount of capital.[10/] Inasmuch as the enterprise value of a utility may be based on overall revenues, rather than just earnings, I would argue that the hypothesis extends to operating expenses, as well. In any case, since shareholders, through the board of directors, are ultimately responsible for approving the overall budget, the Commission would appropriately exercise caution when reviewing and approving the overall budget the Company proposes to establish rates in this matter.

Q. IF THE COMMISSION DOES NOT REJECT THE COMPANY'S FILING, WHAT IS YOUR RECOMMENDATION REGARDING THE USE OF BUDGETS IN THIS MATTER?

A. If the Commission does not reject the Company's filing altogether, I recommend that the Commission require the Company to revise its rate request based either on a historical test year or a combined historical/future test year to better ensure that the Company's approved rates reflect known and measurable expenses. If, however, the Commission continues to allow the Company to use a future test year, I recommend the Commission give the Company's budgets appropriate weighting when considering the totality of the Company's request for a rate increase sought in this matter. I primarily discuss this below with respect to the Company's budgeted staffing levels.

a. Budgeted Staffing Levels

Q. HOW MANY INCREMENTAL FULL-TIME-EQUIVALENT EMPLOYEES DOES THE COMPANY REQUEST IN THIS MATTER?

A. Relative to 2016 staffing levels, the Company proposes 269.8 additional employees.[11/] That is a 10.4% increase to the Company's overall staffing levels.[12/]

10/ See Averch, Harvey; Johnson, Leland L. "Behavior of the Firm Under Regulatory Constraint" American Economic Review Vol 52 No. 5 at 1052–1069 (1962).

11/ Exh. No. PGE/400 at 11, Table 2

12/ Id.

Q. WHAT IS DRIVING THE INCREASE?

A. In general, information technology and transmission and distribution expenses appear to be driving the increase.[13] However, the Company's justifications for these increases do not always appear logical. For instance, the Company notes that one of the driving factors in FTE increases is FTE increases. In other words, the Company's hiring of more employees requires it to hire even more employees to ensure appropriate ratios of line crews to storeroom personnel.[14]

Q. IN THE LONG TERM, HOW SHOULD THE COMPANY MANAGE ITS STAFFING LEVELS?

A. Over the long term, a utility's overall staffing levels are best managed to correspond roughly to changes in its loads. If, for example, the loads of a utility are expected to remain flat, one could rationally assume that there would be no need for dramatic increases to staffing levels. In fact, in such a flat-load scenario, the utility would be ill advised to increase its staffing levels, absent a showing of net benefits, as doing so would put unnecessary upward pressure on rates. Similarly, if loads were declining, one would rationally expect the Company to find ways to reduce its staffing levels. Finally, if loads were increasing, the expectation would be that the Company would have a need to increase its staffing levels.

Q. IS IT SUSTAINABLE IF STAFFING LEVELS CONSISTENTLY EXCEED LOAD GROWTH?

A. No. If the Company increases its staffing levels in a manner that exceeds load growth, it will put systematic upward pressure on rates, that in the long run, would not be sustainable. For

---

[13] Id.

[14] Exh. No. PGE/800 at 17:4-11.

this reason, I believe it is appropriate for the Company to target staffing levels that correspond generally to its expected load growth.

Q. HOW DO THE EMPLOYEE LEVELS AT THE COMPANY COMPARE TO THOSE OF OTHER SIMILAR REGIONAL INVESTOR-OWNED UTILITIES?

A. When benchmarked against information presented in Puget Sound Energy's ongoing rate case, the Company's FTE count already appears to be too high. As detailed in Table 2, below, the Company's labor proposal would result in staffing levels that are roughly commensurate with Puget Sound Energy's, notwithstanding the fact that the Company is a smaller utility measured both in terms of revenues and utility plant. I compared the Company with Puget Sound Energy because they are the only two regional utilities that operate within a single state.

TABLE 2
<u>Comparison of PGE Staffing Levels to Puget Sound Energy</u>

	PGE*	Puget Sound Energy**
Total Employees	2,851	2,871
Revenues ($m)	1,883	3,164
Ratio	151%	91%
Rate Base ($m)	4,593	6,881
Ratio	62%	42%

* Proposed
** Includes both gas and electric operations

Based on the above figure, the Company's staffing levels would appear to already be approximately 67% and 49% higher than the staffing levels of PSE, when considered as a ratio of revenues and rate base, respectively.

Q. HOW PRESSING IS THE NEED FOR ADDITIONAL FTE THE COMPANY SEEKS IN THE TEST PERIOD?

A. Most of the Company's proposed increase to staffing levels appears to be discretionary, based on strategic initiatives in the test period. For example, the Strategic Asset Management ("SAM") program is described in PGE/800 as an early replacement program, which is largely discretionary on the part of the Company, and which presumably could be postponed or phased in more gradually.

Q. HAS THE COMPANY ADEQUATELY DEMONSTRATED THAT THESE DISCRETIONARY PROGRAMS PRODUCE VALUE TO RATEPAYERS?

A. If the discretionary programs the Company proposes produce benefits to ratepayers, one would expect that the Company's budget would contain offsetting adjustments to reduce revenue requirement by an amount exceeding the cost of the incremental employee. To my knowledge, these types adjustments are not present in the Company's budget.

Q. WHAT DO YOU PROPOSE?

A. In the spirit of gradualism, I propose the Commission limit the Company's budgeted growth in FTE to the rate of its expected load growth, prior to the effects of energy efficiency. In 2016, the Company experienced normalized loads of 19,147 MWh, which was already down materially from 2015 due in part to the loss of a large customer.[15/] After the application of price elasticity and incremental energy efficiency, the Company expects loads to be approximately 19,124 MWh in 2018, or an approximate 0.1% reduction relative to 2016 levels.[16/] Prior to the effects of incremental energy efficiency, however, the Company expects

15/ Exh. No. PGE/1201 at 1.
16/ Exh. No. PGE/1202 at 1.

loads to be approximately 19,426 MWh, or an approximate 1.46% increase relative to 2016.[17/] Thus, I propose that the Commission limit the budgeted FTE levels of the Company, including both expense and capital components, based on a 1.46% increase relative to 2016 levels or an increase of 37.7 FTE.

Q. WILL THIS PROPOSAL REQUIRE THE COMPANY TO FURTHER PRIORITIZE ITS EXPENDITURES IN THE TEST PERIOD?

A. Yes. For reasons discussed previously, the Commission would appropriately establish the Company's budget in a manner that requires it to further prioritize its expenditures. Given the levels of load growth the Company expects, it could not be said to be in the public interest for the Company to follow through with the significant increases to its staffing levels it recommends in its initial filing.

b. Capital Budget

Q. SHOULD CORRESPONDING ADJUSTMENTS BE MADE TO THE COMPANY'S CAPITAL BUDGET?

A. Yes. The Company proposes approximately $465.5 million in capital expenditures through the end of 2017. Approximately $168.7 million of the annual capital budget, however, is expected to come online in the month of December. This amount of capital to be placed in service in December 2017, the cutoff date for capital to be included in this matter, represents 36.2% of the total capital the Company expects to place in service in 2017.

Q. WHY IS IT PROBLEMATIC THAT SUCH A DISPROPORTIONATE AMOUNT OF CAPITAL IS PLACED IN SERVICE IN DECEMBER?

A. If capital were placed into service ratably over the year, one would expect 1/12th or 8.3% of the total annual capital to be placed in service in December. That expectation corresponds roughly

17/ Exh. No. PGE/1201 at 1.

to the percentage of annual expenditures that closed to plant in 2016, which was approximately 5.1%. Thus, the 36.2% amount the Company proposes in this matter is disproportionate, which may be an indication that the Company has front-loaded capital for the purpose of getting the amounts reflected in rate base in this matter.

Q. WILL ALL OF THE CAPITAL THE COMPANY PROPOSES COME ONLINE BY THE END OF 2017?

A. There is no way of knowing with certainty whether the disproportionate amount of capital will come online by the end of 2017. It is probable, however, that at least some of the capital will miss the December 31, 2017 cutoff date.

Q. HAS THE COMPANY HISTORICALLY OVER-FORECAST CAPITAL?

A. Based on an analysis that I conducted in the 2016 GRC, my experience is that the Company has historically over-forecast its capital expenditures,[18/] although a similar analysis was not performed for this testimony.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO STAFFING AND CAPITAL BUDGETS?

A. For capital, I recommend that half of the December 2017 capital budget be delayed and placed into service in early 2018, resulting in a $84.3 million reduction to rate base. For staffing levels, I have not run the full FTE labor model to calculate the impact of increasing staffing levels by 37.7 FTE relative to 2016 levels. For purposes of this filing, I have assumed an approximate $10.0 million placeholder for this amount, and request that the Company perform the calculation as a part of its rebuttal filing, or through discovery.

18/ Docket No. UE 294, ICNU/200 at 18-27.

III. DEPRECIATION EXPENSES

Q. WHAT IS THE ISSUE YOU HAVE IDENTIFIED WITH RESPECT TO DEPRECIATION EXPENSE?

A. In Docket No. UM 1809, the Company filed a depreciation study, where it calculated depreciation expenses of $286.1 million, based on plant levels as of December 31, 2015.[19/] Parties in that proceeding, including ICNU, are currently in the process of finalizing a stipulation in that matter. Notwithstanding, I am concerned with the way in which the Company has taken the results of the depreciation study and incorporated those results into its revenue requirement study.

Q. WHAT SPECIFICALLY ARE YOU CONCERNED ABOUT?

A. I have two general concerns with the way in which the Company has included depreciation expenses in the revenue requirement study. First, in contrast to the $286.1 million of depreciation expenses calculated in the depreciation study—an amount which will ultimately be based on the outcome of the pending stipulation—the Company proposes depreciation expenses of $328.4 million, prior to any adjustments.[20/] Second, the Company increases depreciation expenses by approximately $7.3 million related to asset retirement obligations.[21/]

Q. WHY IS THERE A DIFFERENCE BETWEEN THE DEPRECIATION STUDY RESULTS AND THE EXPENSE IN REVENUE REQUIREMENT?

A. In ICNU Data Request 099, subpart b, the Company was requested to reconcile the differences between the depreciation study results and the amount included in revenue requirement.[22/] In subpart c, the Company was also requested to explain the appropriateness of the $7.3 million

---

19/ Exh. No. ICNU 303 at 31
20/ Id.
21/ Id. at 30-31.
22/ Id.

adjustment related to asset retirements. In response, the Company simply explained that the depreciation expense calculated in the depreciation study was based on plant balances as of December 31, 2015, in contrast to the plant balances of December 31, 2017 used in this matter. The Company identified the addition of the Carty Generating Station as the primary reason for the difference between the two values. The Company also pointed to Exhibit PGE/203—although the values in Exhibit PGE/203 were based on hard-coded numbers, and thus, did not provide any meaningful insight into the reasons the depreciation expense calculated in the depreciation study were different than the amount of depreciation expense included in revenue requirement.

Q. DID THE COMPANY PROVIDE WORKPAPERS SUPPORTING THE DIFFERENCE BETWEEN THE DEPRECIATION STUDY AND THE REVENUE REQUIREMENT MODEL?

A. No. The Company did not provide any workpapers to demonstrate how it used the results from the depreciation study to derive the depreciation expense proposed in revenue requirement.

Q. DOES CARTY EXPLAIN THE DIFFERENCE BETWEEN THE DEPRECIATION STUDY AND DEPRECIATION EXPENSE IN REVENUE REQUIREMENT?

A. No. As noted in Exhibit No. PGE/203, the partial year impact of Carty Generating Station on revenue requirement was only \$6.8 million,[23/] which does not explain the approximately \$42.3 million variance between the depreciation study results and the depreciation expenses calculated in this matter. On an annualized basis, the depreciation expense for Carty was forecast to be \$13.5 million.[24/] Thus, at a maximum, the Company's explanation would justify baseline depreciation expenses of only \$299.6 million, prior to any adjustments.

23/ Exh. No. PGE/200 at 7:16-19.
24/ Exh. No. PGE/203.

Q. SHOULD CARTY DEPRECIATION BE CALCULATED USING THE AVERAGE SERVICE LIFE METHODOLOGY?

A. Yes. Consistent with the stipulation in Docket No. UM 1679, depreciation expense for Carty is appropriately calculated using the Average Service Life ("ASL") methodology.[25] Since the depreciation expense for Carty Generating Station was not included in the depreciation study, a separate adjustment is needed to the revenue requirement model in this matter, if the ASL method is to be used for the Carty Generating Station in Docket No. UM 1809.

Q. IS IT APPROPRIATE FOR THE COMPANY TO INCLUDE A SEPARATE ADJUSTMENT FOR ASSET RETIREMENT OBLIGATIONS?

A. No. The Company already includes a negative net salvage component in depreciation expense to account for the cost of removing and decommissioning assets. This can be noted in Attachment A, Part I of the depreciation study in Docket No. UM 1809.[26] Including a separate $7.3 million adjustment to depreciation expense for asset retirement obligations would represent decommissioning and removal costs in addition to those decommissioning and removal costs already reflected in the depreciation rates calculated in the depreciation study. For that reason, I believe it is inappropriate to include this amount as a separate adjustment.

Q. WHAT DO YOU PROPOSE WITH RESPECT TO DEPRECIATION EXPENSES?

A. Absent workpapers justifying the increase in depreciation expense relative to the depreciation study results, I recommend establishing baseline depreciation expense of $299.6 million, which represents the depreciation study results adjusted for Carty, in the manner described above. Relative to the approximately $328.4 million of baseline depreciation expense include in the filing, this adjustment represents a $28.8 million reduction to depreciation expense. In

---

[25] Docket No. UM 1679, Stipulation ¶ 4 (June 30, 2014).

[26] Docket No. UM 1809, Depreciation Study, Attachment A, Part 1 at 40-43.

addition, I recommend removing the Company's adjustment for asset retirement obligations in the amount of $7.3 million. Combined, this recommendation results in a total adjustment related to depreciation expense of $36.1 million, prior to application of the settlement in principle that has been reached in Docket No. UM 1809.

IV. MEDICAL BENEFITS EXPENSES

Q. WHAT HAVE YOU DISCOVERED BASED ON YOUR REVIEW OF THE COMPANY'S BUDGET FOR MEDICAL BENEFITS EXPENSE?

A. A reminder of why the Commission should exercise caution when considering the Company's proposed budgets can be noted in medical benefits expenses, FERC accounts 9260004 (union) and 9260005 (non-union). Based on the information presented in the Company's revenue requirement workpapers, the Company has budgeted medical benefits to increase by $3.0 million and $7.4 million for union and non-union benefits, respectively.[27/] In 2016, actual medical benefits expenses were only $11.6 million and $26.6 million for union and non-union benefits, respectively. Thus, the budget of the Company reflects medical benefits expenses of $14.4 million and $34.1 million for union and non-union benefits, respectively. That is a 24% and 28% increase to the respective accounts. Upon closer review, however, there is little doubt that the proposed increases are based largely on unsupported, and in some cases duplicative, escalation assumptions.

---

27 Exh. No. ICNU/302 at 2.

Q. WHAT COSTS ARE GENERALLY CLASSIFIED AS MEDICAL BENEFITS EXPENSES?

A. The costs assigned to the above accounts generally consist of the employer portion of the costs associated with the medical, dental, and vision insurance plans of the Company, including reimbursements for those employees choosing not to participate in the plans.

Q. HOW DID THE COMPANY DEVELOP ITS BUDGET FOR THE TEST PERIOD?

A. In response to ICNU DR 005, the Company identified the changes related to medical benefits expense for the respective accounts relative to the actual medical benefits expenses incurred in 2016. The Company identified several drivers for the increase in medical benefits expense. These drivers have been presented in Table 3, below, along with columns indicating my proposed changes to the Company's budgeting assumptions.

TABLE 3
Breakdown of Budgeted Increase in Medical Benefits Expense Increase
Relative to 2016 Actual Expense
($000)

		Company Proposed				ICNU Proposed			
		9260004	9260005			9260004	9260005		
Ln	Description	Union	Non-Union	Total		Union	Non-Union	Total	
1	Outside Services	$ (233)	$ 153	$ (80)		$ (233)	$ 153	(80)	
2	2016 Actual to Budget Results	71	351	423		-	-	-	
3	2017 Med. Premium Esc.	1,696	410	2,106		1,696	410	2,106	
4	2017 Incremental FTE	1,645	657	2,301		822	328	1,151	
5	2017 Other Premium Esc.	96	-	96		96	-	96	
6	2018 Premium Esc.	2,494	909	3,403		-	-	-	
7	2018 Incremental FTE	346	-	346		-	-	-	
8	Inflation Escalation	1,017	435	1,452		-	-	-	
9	Change in Retiree Medical	304	112	416		-	-	-	
10	**Total Budgeted Increase**	**$ 7,436**	**$ 3,027**	**$ 10,464**	(a)	**$ 2,381**	**$ 892**	**$ 3,273**	(b)
11							**Adjustment (a)-(b):**	**$ 7,191**	

Q. HOW DID THE COMPANY DERIVE THE AMOUNTS DETAILED IN CONFIDENTIAL TABLE 3?

A. The Company's response to ICNU DR 005 consisted only of hard-coded numbers, so it was not possible from that request to determine how the Company calculated the escalation amounts. Accordingly, ICNU requested further information in ICNU DR 036 regarding the specific calculations the Company performed to develop its budget, as well as clarification regarding some of the information presented in Table 3.[28]

---

[28] Exh. No. ICNU/303 at 12-14

Q. DID THE COMPANY NOTE ANY CONCEPTUAL ERRORS IN ITS BUDGET PROPOSAL?

A. Yes. As detailed on Line 8 of Table 3, the Company's budget includes an inflationary assumption, in addition to the escalation assumed with respect to its premiums. In reviewing the calculation, it was apparent that the premium escalation assumptions already accounted for inflation in the Company's medical benefits expenses, and thus, it appeared to me to be duplicative to include both an inflation escalation assumption, in addition to a premium escalation assumption.

When asked whether the Company agreed that it was inappropriate to include an inflationary assumption, in addition to a premium escalation assumption, the Company noted in ICNU DR 036, subpart d, that it had inadvertently included the inflationary assumption and would remove that assumption in its reply filing.[29]

Q. IS THE 2016 BUDGET VARIANCE, SHOWN ON LINE 2, APPROPRIATELY CONSIDERED AS AN INCREASE TO BENEFITS EXPENSE?

A. No. On line 2 of Table 3, the Company increased the amount of benefits expense by an amount representative of the difference between the 2016 budget and actual 2016 results. I disagree that this amount is appropriately reflected as an increase in this matter. The fact that actual results in 2016 were less than the amount budgeted is not a reason to increase the budget in 2017.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS WITH RESPECT TO MEDICAL BENEFITS ESCALATION?

A. I propose to limit the escalation to be based only on those increases to medical benefits expenses that are known and measurable. Thus, I have excluded escalation for 2018 in the

---

29/ Id. at 14.

calculation of my adjustment above. As I have reviewed the escalation assumptions that the Company used, there appears to be material uncertainty regarding the escalation in medical benefit premiums in 2018. For example, the Company forecasts escalation in union medical benefits in the amount of [redacted]% for 2017. Yet, with no explanation or supporting calculations, the Company proposed [redacted]% escalation for union medical benefit premiums in 2018. Since the 2018 premium escalation amounts appear to be speculative, however, I disagree that those amounts are appropriately included in the budget for ratemaking purposes.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO MEDICAL BENEFITS EXPENSES?

A. I recommend that medical benefits expense be calculated in a manner that 1) excludes a provision for inflationary escalation; 2) eliminates the budget variance for 2016; and 3) eliminates the premium escalation assumption for 2018. As noted in Confidential Table 3, above, the impact of my recommendation is an approximate $7.2 million reduction to the Company's revenue requirement.

V. OTHER REVENUES

Q. PLEASE EXPLAIN OTHER REVENUES.

A. Other revenues are miscellaneous items from which the Company earns income, such as rent, transmission revenue, and steam sales revenues.

Q. HAS THE COMPANY IDENTIFIED ANY ERRORS WITH RESPECT TO ITS CALCULATION OF OTHER REVENUES?

A. Yes. In response to ICNU Data Request 27, subpart b, the Company noted that "From 2016 to 2018, revenues from OHSU are projected to decrease by approximately $200,000 because PGE inadvertently omitted $160,000 of revenue from this budget."[30/] The Company later confirmed that it would include this additional revenue in its reply filing.

Q. HAVE OTHER PARTIES RAISED CONCERNS ABOUT THE COMPANY'S UNDER-FORECASTING OF OTHER REVENUES?

A. Yes. In the Company's 2015 GRC, Docket No. UE 294, the Citizens' Utility Board noted that the Company had under-forecast other revenues by an average $3.0 million over the period 2006 through 2014, and in only one of those years had the Company over-forecast other revenues.[31/] The parties ultimately settled this issue by increasing the forecast of other revenues by $1.5 million.[32/]

Q. WHAT DO YOU BELIEVE IS THE CAUSE OF THE COMPANY'S HISTORICAL UNDER-FORECASTING?

A. Other revenues are relatively difficult to forecast because they consist of a number of miscellaneous revenue items. Many of these other revenue items are not necessarily known at the time the Company files its rate case, and it appears that there are instances where the Company receives revenue items that it simply did not expect at the time of the rate case filing.

Q. WHAT DO YOU PROPOSE?

A. For purposes of this filing, I do not propose any additional adjustment to other revenues, other than the error correction identified above. Notwithstanding, the budgeted reduction to other revenues of $6.0 million, detailed in Exhibit ICNU/302,[33/] is concerning to me and I believe that the Company should have provided a better explanation for the reasons other revenues are declining by such a material amount in 2018.

30/ Exh. No. ICNU/302 at 8.

31/ Docket No. UE 294, CUB/100 at 6:11-7:4.

32/ Docket No. UE 294, Order No. 15-356 at 9 (Nov. 3, 2015).

33/ Exh. No. ICNU/302 at 8.

VI. ALLOWANCE FOR DEFERRED INCOME TAXES

Q. WHAT IS YOUR RECOMMENDATION RELATED TO ALLOWANCE FOR DEFERRED INCOME TAXES.

A. I contest several aspects of the Company's calculation of allowance for deferred income taxes ("ADIT"). These adjustments are summarized in Table 4, below, which represent a reduction to rate base:

TABLE 4
Contested ADIT Adjustments
($000)

Ln. No.	Adj. No.	ADIT Item	Company Proposed	ICNU Opening	Adjustment
1	IN-7	Production Tax Credit Carryforward	60,019	-	(60,019)
2	IN-8	Minimum Tax Credit Carryforward	7,239	-	(7,239)
3	IN-9	Deferred Broker Settlements	3,244	(1,422)	(4,666)
4	IN-10	Accrued Incentives	7,032	3,516	(3,516)
5	IN-11	Stock Incentive Plan	4,487	-	(4,487)
6	IN-12	Accrued Vacation	6,784	-	(6,784)
7	IN-13	Boardman Biomass Revenues	1,103	-	(1,103)
			-	-	-
9		**Total ADIT Adjustments**	**89,907**	**2,093**	**(87,814)**

Q. WHAT IS ADIT?

A. ADIT is a rate base item associated with the timing differences between the recognition of cost and revenues for ratemaking purposes and the recognition of costs and revenues for tax accounting purposes. For ratemaking purposes, tax expense is calculated based on the accounting methodologies used to establish net operating income for regulatory accounting purposes, not based on the timing of when costs and revenues are recognized for tax purposes. To the extent that the differing accounting methodologies result in the payment of taxes at different times than tax expense is recognized for regulatory purposes, the timing differences are accounted for through ADIT as a source—or use—of "no-cost capital."

If a utility recognizes a cost for tax accounting purposes earlier than that cost would otherwise be recognized for ratemaking purposes, ratepayers are provided with a carrying charge on the temporary differences, through a reduction to rate base. Similarly, to the extent that a utility recognizes a cost for tax accounting purposes later than the cost would otherwise be recognized for ratemaking purposes, ratepayers pay a carrying charge on the temporary difference, through an increase to rate base.

Depreciation expense is the most common example. For tax purposes, a utility is provided with the ability to depreciate certain property using an accelerated depreciation methodology. For regulatory purposes, however, depreciation expense is calculated based on complex depreciations studies, which typically assume longer lives. Thus, a utility may deduct the cost of plant—claiming a tax benefit—earlier than reflected in the tax expense used for ratemaking. The cash benefit received by the utility as a result of this dynamic is treated as a source of no-cost capital, and deducted from rate base through ADIT.

Q. DOES THE INTERNAL REVENUE CODE REQUIRE THE PUBLIC UTILITY TO INCLUDE ADIT FOR ALL TEMPORARY BOOK/TAX DIFFERENCES?

A. No. Under the Internal Revenue Code ("IRC") § 168(f), the Company is only required to include in the provision for deferred income taxes reflected in ADIT the effects of accelerated depreciation. The Treasury regulations make this point very plainly:

> The normalization requirements of section 167(l) with respect to public utility property defined in section 167(l)(3)(A) pertain only to the deferral of Federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books

> of account. Regulations under section 167(l) do not pertain to other book-tax timing differences with respect to State income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.[34]

Thus, with respect to other timing differences, such as those discussed below, the Commission has a great deal of latitude in evaluating whether the particular timing difference truly represents a source—or use—of no cost capital, which is appropriately include in rate base for ratemaking purposes.

Q. WHAT INFORMATION HAVE YOU REVIEWED IN SUPPORT OF YOUR RECOMMENDATION?

A. My recommendation is based on the values presented in the PGE/200 workpaper titled "2018 Deferred Tax Details." Based on that workpaper, I submitted ICNU DR 64, requesting additional information on a number of items presented in the Company's workpapers.[35] Additional follow up was conducted in ICNU DRs 92, 93, 94, 95, and 98.[36]

a. ADIT – Production Tax Credit Carryforwards

Q. WHAT ARE PRODUCTION TAX CREDITS CARRYFORWARDS?

A. IRC § 45, establishes the availability of production tax credits for generation from certain renewable sources of power supply.[37] Production tax credits are considered to be a general business credit, the utilization of which are governed by IRC § 38. Under that section, a general business credit may not reduce a business's tax liability below 25% of its regulated tax liability.[38] In addition, a general business credit may not reduce a business's tentative minimum tax below its tentative minimum tax, the tax computed for purposes of the alternative

---

34/ IRC § 168(f)
35/ Exh. No. ICNU/303 at 15-19.
36/ Id. at 20-29.
37/ IRC § 45
38/ IRC § 38

minimum tax.[39/] To the extent that a credit is not utilized in any particular tax year, however, it may be carried forward to offset tax liability in future tax years for a period of twenty years.[40/]

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

A. According to the workpaper titled "2018 Deferred Tax Detail.xlsx" provided along with Exhibit No. PGE/200, the Company proposes to include $60.0 million in ADIT for production tax credit carryforwards. This amount, along with amounts requested in in the 2016 GRC, have been detailed in Table 5, below.

TABLE 5
Production Tax Credit Carryforward Balance
Forecast Comparison
($000)

	End of Period					
	2015		2016		2017	
Tax Return	34,878	(a)				
2016 GRC	42,427	(b)	60,061	(b)		
2018 GRC			42,098	(c)	60,019	(c)

(a) Represents 2016 beginning balance from Exhibit PGE/200 workpaper "2018 Deferred Tax Details," although this does not tie to 2016 beginning balance in the PTC carryforward analysis conducted in the Company's IRP.

(b) In the 2016 GRC the Company utilized a rate base period of the year ending December 31, 2015. Notwithstanding the Company also provided workpapers forecasting the credit carryforward to the year end 2016, which was significantly greater than what the Company forecasts in this case.

(c) These are the forecast balances used in this proceeding. It can be noted to exceed the actual 2015 tax return balance by a significant margin.

39/ Id.
40/ Id.

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

A. There are four general reasons why it is not appropriate to include production tax credit carryforwards in ADIT in this matter. First, as detailed in Table 5, above, the Company has historically overstated the production tax credit carry forward balances in prior rate cases, relative to the amounts that have actually been included on its tax return. Second, a production tax credit carryforward is created by the Company's inability to generate sufficient taxable income in any given tax year, not a timing difference in the recognition of costs and revenues between tax and regulatory accounting methodologies. Third, the renewable resources underlying the credit were justified based on the assumption that the Company would be able to fully utilize production tax credits, and for that reason, inclusion of production tax credit carryforwards as a use of financing represents an imprudent cost. Finally, the Company is provided with a number of options to reduce its tax liability in any given tax year, and thus if provided with the ability to earn a return on the production tax credits, it will have little incentive to utilize the credit carryforwards until they are about to expire.

Q. HAS THE COMPANY ACCURATELY PREDICTED PRODUCTION TAX CREDITS IN PRIOR PROCEEDINGS?

A. As noted in Table 6, in the 2016 GRC, the Company over-forecast the production tax credit carryforward balance by approximately $7.5 million relative to the amount that was actually included on the Company's tax return, although there remains some uncertainty as to the actual amount that was included on the Company's 2015 tax return. Similarly, in that case the Company forecast the production tax credit carryforward balance to grow to $60.1 million by year end 2016. As I understand, the Company has not yet filed its tax return for 2016. Typically, the Company's return is filed closer to the September 15, 2015 extended filing deadline. In this proceeding, however, the Company has revised its forecast for the year-end 2016 balance downward to be only $42.1 million. Notwithstanding, it continues to expect the balance to grow by the end of 2017 to be 60.1 million, an approximately 43.6% increase. Given the variability of past forecasts, I have little confidence in the Company's ability to predict the balance through the end of 2017.

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

A. No. A production tax credit carryforward is not created as a result of any difference between tax and regulatory accounting. It is driven by the ability of the Company to generate sufficient taxable income in a particular tax year to utilize the credits, based on the totality of receipts, deductions, and other tax items reflected on the Company's tax return. If, for example, the Company's revenues were lower than expected due to unfavorable market conditions, such a scenario could reduce the taxable income of the Company, resulting in the inability to utilize production tax credits.

Q. WHAT COMPANY RESOURCES GENERATE PRODUCTION TAX CREDITS?

A. Production tax credits are primarily produced by the Biglow and Tucannon River wind facilities, although the Company generates a small amount of production tax credits from the Oak Grove solar project. In addition, the production tax credit generated from Phase 1 of the Biglow wind facility will begin to phase out later this year, followed by the phasing out of credits for Biglow Phases 2 and 3 in 2019 and 2020, respectively.

Q. WERE THESE RESOURCES JUSTIFIED BASED ON THE ASSUMPTION THAT PRODUCTION TAX CREDITS WOULD BE FULLY UTILIZED?

A. According to my understanding, yes. For instance, in justifying the prudence for Tucannon, the Company noted that the top three factors it analyzed in the request for proposals that ultimately led to the selection of Tucannon were "capacity, transmission costs and risks, and the ability to use production tax credits."[41/] To my knowledge, there was no contemplation on the part of the Company that it might not be able to utilize the credits generated from these facilities when considering whether to make the investments.

Q. IS THIS EVIDENCE THAT CARRYING COSTS ASSOCIATED WITH PRODUCTION TAX CREDIT CARRYFORWARDS RESULT FROM IMPRUDENT MANAGEMENT?

A. Yes. Unlike the many things which can go wrong when acquiring and constructing utility-scale generating resources, the Company's ability, or lack thereof, to utilize production tax credits is something that can be reasonably foreseen. When justifying investments of this magnitude on the basis of realizing tax benefits, it would be reasonable for the Company to obtain tax advice to determine whether the credits could actually be claimed on the utility's tax return. Thus, I do not believe that ratepayers are appropriately responsible for the production tax credit carryforward balances in rate base.

Q. DOES THE COMPANY HAVE AN INCENTIVE TO UTILIZE PRODUCTION TAX CREDITS CARRYFORWARDS ON ITS TAX RETURN?

A. No. If production tax credit carryforwards continue to be reflected in rate base, the Company has little incentive to utilize those assets. While earning a return on these tax assets, the Company has an incentive to utilize them as a last resort.

41/ Docket No. UE 283, Exh. No. PGE/400 at 7:17-19.

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

A. Removing production tax credit carryforwards from ADIT results in an approximate $60.0 million reduction to rate base and an approximate $7.4 million reduction to revenue requirement.

<u>b. ADIT – Minimum Tax Credit Carryforwards</u>

Q. WHAT ARE ALTERNATIVE MINIMUM TAX CREDIT CARRYFORWARDS?

A. The Alternative Minimum Tax ("AMT") is a supplemental income tax that applies to taxpayers taking large amounts of deductions and credits. It is based on the general principle that certain taxpayers, after accounting for various tax benefits provided throughout the Internal Revenue Code, should pay a minimum level of tax. Notwithstanding, if the amount of the AMT payment exceeds the regular tax liability in any given year, the excess amount may be carried forward and reflected as a credit against future year's regular tax liability.

Q. WHAT AMOUNT OF AMT CREDIT CARRYFORWARDS ARE INCLUDED IN ADIT IN THIS MATTER?

A. According to the workpaper titled "2018 Deferred Tax Detail.xlsx" provided along with Exhibit No. PGE/200, the Company has proposed to include $7.3 million in ADIT in connection with the AMT credit carryforwards. According to the Company's response to ICNU DR 64, this amount is entirely attributable to AMT tax payments made for tax year 2008.

Q. WHAT GUIDANCE HAS THE IRS PROVIDED?

A. Attached as Exhibit No. ICNU/304 is a Private Letter Ruling ("PLR") 201418024, which ultimately found that the exclusion of an AMT credit carryforward from ADIT in that case was not prohibited under the tax normalization requirements of the IRC.

Q. IS AN AMT CREDIT CARRYFORWARD APPROPRIATELY INCLUDED IN ADIT FOR RATEMAKING PURPOSES?

A. No. While there is no question that the Company paid AMT for the 2008 tax year, I disagree that such payment represents any sort of financing benefit to ratepayers upon which the Company should be provided with a return. The fact that the Company may have paid AMT on a tax return ten years ago, does not mean that ratepayers should be responsible for financing the cost of that tax attribute. The Company's unexpected payment of AMT in 2008 should be considered no differently than, for instance, unexpected power costs resulting from an outage. For that reason, I believe the AMT credit carryforward should be excluded from ADIT.

c. ADIT - Accrued Incentives & Stock Incentives

Q. WHAT AMOUNT OF ADIT HAS THE COMPANY PROPOSED WITH RESPECT TO ACCRUED INCENTIVES?

A. The Company has included approximately $7.0 million in ADIT associated with accrued incentives and approximately $4.5 million in management stock incentives.

Q. HOW DO ACCRUED INCENTIVES GIVE RISE TO DEFERRED TAXES?

A. According to ICNU DR 64, subpart k, incentives are not deductible until paid, thus giving rise to deferred taxes.

Q. DOES THE COMPANY INCLUDE THE COST OF INCENTIVES IN CUSTOMER RATES?

A. The Company excludes 100% of Officer Long-Term Incentive Program costs and 50% of the costs of all other incentives.[42/] The Company states that it excluded these costs to help mitigate the overall rate increase, but asserts that all of its incentive costs are "prudent and appropriate."[43/] I do not agree that it would be appropriate to require customers to pay the full

---

42/ Exh. No. PGE/400 at 18:7-8.

43/ Id. at 18:12-18.

costs of the Company's incentive packages and, in any event, understand that the Company's proposed treatment of other incentive costs is generally consistent with historical regulatory practice.

Q. WHAT IS YOUR RECOMMENDATION RELATED TO ADIT ASSOCIATED WITH ACCRUED INCENTIVES?

A. I recommend that the ADIT associated with accrued incentives be reduced by 50%, or approximately $3.5 million, consistent with the regulatory treatment of incentives generally. In addition, I recommend that the ADIT associated with management stock incentives be reduced by 100%, consistent with the Officer Long-Term Incentive Program. It would be asymmetrical to exclude these costs from customer rates, but include the ADIT effects of these same costs in customer rates.

<u>d. ADIT – Accrued Vacation</u>

Q. WHAT AMOUNT OF ADIT HAS THE COMPANY PROPOSED WITH RESPECT TO ACCRUED VACATION?

A. The Company has included approximately $6.8 million in ADIT related to accrued vacation.

Q. WHY HAS THE COMPANY INCLUDED ADIT RELATED TO ACCRUED VACATION?

A. For financial reporting purposes, the Company records vacation expenses when accrued. For tax purposes, however, the Company can only deduct the expense as the amounts are actually paid through wages.

Q. DOES THE SAME LOGIC APPLY TO THE COSTS INCLUDED IN REVENUE REQUIREMENT?

A. No. For regulatory purposes, the Company accounts for vacation in the same manner as done for tax accounting purposes. This is evident from the fact that the Company does not include accrued vacation expenditures as a source of cash in its lead-lag study. For that reason, ratepayers do not receive the cash benefits associated with accruing vacation expenses prior to the period that it is ultimately paid, through wages. For that reason, it is not appropriate to include ADIT for accrued vacation because accrued vacation does not represent a source of cash in revenue requirement.

e. ADIT – Deferred Broker Settlements

Q. WHAT ARE DEFERRED BROKER SETTLEMENTS IN THE CONTEXT OF ADIT?

A. These amounts represent transactions that have been financially settled by clearing brokers prior to the contract delivery date. For tax purposes, these amounts are recognized when the payments are made, whereas for regulatory accounting purposes, the gains and losses are recognized in the period corresponding to the delivery date.

Q. HOW MUCH ADIT HAS THE COMPANY INCLUDED WITH RESPECT TO DEFERRED BROKER SETTLEMENTS IN THE TEST PERIOD?

A. The Company has included approximately \$3.2 million in ADIT for deferred broker settlements in the test period.

Q. DID THE COMPANY IDENTIFY AN ERROR IN ITS THE CALCULATION?

A. Yes. According to subpart o to the Company's response to ICNU DR 64, the Company suggested that the amount of deferred broker settlements for 2018 should actually be a \$1.4 million benefit to ratepayers. Thus, this ADIT item should be reduced by \$4.6 million.

f. Boardman Biomass Test Fire

Q. DID THE COMPANY INADVERTENTLY INCLUDE ADIT ASSOCIATED WITH DEFERRED BOARDMAN TEST BURN REVENUES?

A. Yes. In response to ICNU Data Request 095, subpart f, the Company noted that it "inadvertently included \$1.1 million for an accumulated deferred income tax (ADIT) asset associated with the deferred revenue discussed in part e, above. Because the liability associated with the deferred revenue was not included in rate base, the ADIT asset should not have been included either."[44/] I have removed this amount in my recommendation above, along with a small amount of R&D expenditures, which are not part of ADIT and I discuss below.

Q. PLEASE PROVIDE SOME BACKGROUND ON THE BOARDMAN BIOMASS PROJECT.

A. As an alternative to decommissioning the Boardman Generating Facility after it stops burning coal in 2020, the Company has been investigating the feasibility of converting it to a biomass-fueled generation facility. The Company has been researching this option since at least 2010.[45/] Since that time, the Company has proposed and performed test burns of biomass at Boardman, but has yet to conclude that Boardman could successfully be converted to a biomass-fueled electric generation facility. These test burns have been significantly delayed in the past.

Q. WHAT ARE THE RESEARCH AND DEVELOPMENT COSTS THE COMPANY HAS PROPOSED TO INCLUDE IN THIS CASE?

A. As part of its research and development budget, the Company proposes to include $410,000 to continue to test burn biomass and to develop a supply chain.[46/]

Q. HAS COMMISSION STAFF MADE A PROPOSAL WITH RESPECT TO THESE COSTS?

A. Yes. In its opening power cost testimony, Staff proposed to move these costs from general rates to power costs.[47/]

44/ Exh. No. ICNU/303 at 28

45/ Exh. No. PGE/604 at 8.

46/ Id. at 6, 8.

47/ Exh. No. Staff/300 at 10-12

Q. DO YOU AGREE WITH STAFF'S PROPOSAL?

A. No. I propose to eliminate these costs from rates altogether. Given the inability to date to develop an acceptable biomass product that is capable of being burned at Boardman, it appears to be increasingly unlikely that this project will reach commercial operation. Furthermore, even if the Company were successful in converting Boardman, its most recent Integrated Resource Plan ("IRP") indicates that it would be far from the most economic resource the Company could acquire.[48/] While I have significant concerns with the IRP studies the Company performed, according to its analysis, the portfolio that included Boardman Biomass was the third worst scoring portfolio it analyzed.[49/] Thus, there is no indication that this resource would benefit customers. Continuing to research the use of biomass at Boardman does not appear to be a prudent use of customer money.

VII. RATE SPREAD AND RATE DESIGN ISSUES

a. Customer Impact Offset

Q. HOW HAS THE COMPANY APPLIED THE CUSTOMER IMPACT OFFSET TO SCHEDULE 89?

A. In establishing its rate spread proposal, the Company has proposed to apply an additional amount of customer impact offset ("CIO") to Schedule 89, such that its overall rate increase ties to that for Schedule 90.[50/]

Q. WHAT RATE SCHEDULES RECEIVE THE BENEFIT OF THE CUSTOMER IMPACT OFFSET?

A. The Customer Impact Offset revenues were provided entirely to residential Schedule 7.

48/ Docket No. LC 66, PGE IRP at 337.

49/ Id.

50/ Exh. No. PGE/1400 at 8:7-10.

Q. HOW MUCH GREATER, RELATIVE TO THE AVERAGE, IS THE COMPANY'S PROPOSED RATE INCREASE FOR SCHEDULE 7?

A. Relative to the overall base rate increase of 5.6%, the rate increase proposed for Schedule 7 was 7.3%, or approximately 1.3 times the average, prior to the application of the customer impact offset.

Q. HAS THE CIO HISTORICALLY APPLIED FOR A RATE SCHEDULE RECEIVING 1.3 TIMES THE AVERAGE RATE INCREASE?

A. No. In Docket UE 215, parties stipulated that each party will support application of the CIO only to address rate shock issues.[51/] In that case the CIO was limited to those rate classes that received 2.5 times the average rate increase. Similarly, based on the Stipulation in Docket No. UE 283, the CIO was only applied to schedules receiving 3.0 times the average rate increase. In my view, a rate increase that is 1.3 times the average rate increase is not an instance of rate shock appropriately addressed through the use of the CIO.

Q. ARE THERE ANY OTHER REASONS THAT THE USE OF A CIO IS UNNECESSARY?

A. The Company already applies mechanics to equalize the rate impacts for Schedules 83, 85, 89 and 90.[52/] For that reason, I disagree with the Company's proposal to include extra amounts associated with the customer impact offset for Schedule 89, for the sole purpose of making the rate increase for that schedule equal to Schedule 90.

Q. WHAT DO YOU PROPOSE?

A. I believe there may be better ways to address the disparity in the rate spread between residential and large customer classes in this matter. Accordingly, I propose to eliminate the CIO in favor of a reallocation of the load following credit. Based on the following analysis,

---

51/ Docket No. UE 215, Rate Spread and Rate Design Stipulation at 2 (Aug. 2, 2010).
52/ Exh. No. PGE/1400 21:4-22:3.

one of the drivers of the differing rate impacts between the rate classes has to do with the way that the Company has changed the load following credit allocation. As discussed below, reverting to the load following methodology used in the 2016 GRC would serve as a better mechanism to mitigate the rate impacts for residential customers.

b. Load-following Allocation

Q. PLEASE PROVIDE SOME BACKGROUND ON THE LOAD FOLLOWING CREDIT.

A. In the 2016 GRC, parties agreed to a methodology for applying the load following credit, with the understanding that the Company would perform additional analysis of the load following credit in this proceeding.

Q. WHAT INFORMATION HAS THE COMPANY PROVIDED WITH RESPECT TO THE LOAD FOLLOWING CREDIT IN THIS MATTER?

A. The Company performed studies where it attempted to incorporate the cost of load-following as a component of the marginal cost of generation in its rate spread methodology. This analysis was based on an analysis of the variability of the 15-minute changes in load data for the respective rate classes.

Q. DO YOU AGREE WITH THE COMPANY'S METHODOLOGY?

A. No. The 15-minute ramps in load are only a small portion of costs that have been historically reflected in the load following allocation. The Company's analysis only considers 15-minute ramping requirements, and does account for all of the costs that have been traditionally captured in the load following allocation. Historically, class contribution to factors such as day-ahead, and hour-ahead forecast error would be appropriately viewed as reflected in the load-following credit allocation. In this case, limiting the analysis to 15-minute ramping requirements has narrowed the definition of what was previously considered in the load following allocation methodology. In addition, even in the Company's ramping analysis, it does not appear to have accounted for any diversity impacts between rate schedules.

Q. IS THE CHANGE IN METHODOLOGY CONTRIBUTING TO UNFAVORABLE RATE SPREAD RESULTS?

A. Yes. The Company's methodology produces more disparate rate impacts than the load following credit allocation approved in the 2016 GRC.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE LOAD FOLLOWING ALLOCATION?

A. Using the load following cost allocation methodology approved in the 2016 GRC will more accurately reflect load following benefits and will also produce a leveler rate spread, relative to the Company's proposal in this matter. For these reasons, I recommend that the methodology approved in the 2016 GRC be used in this matter.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. Table 6, below, details how the 2016 load following methodology produces a leveler rate spread, as well as the incremental impact of removing the CIO, as discussed above. In addition, when applying the load following allocation, I reduced the amount of the credit applied solely to Schedule 89 customers from \$0.87/MWh to \$0.25/MWh in order to better equalize the rate increase between Schedule 90 and Schedule 89 customers.

TABLE 6
Base Rate Increase by Rate Schedule

Schedule	Company Proposed	2016 GRC Ld. Follow	Remove CIO
7	7.08%	6.78%	6.99%
15	1.96%	2.85%	2.85%
32	5.68%	5.97%	5.97%
38	8.09%	8.06%	8.06%
47	4.79%	5.04%	5.04%
49	9.07%	9.47%	9.47%
83	4.16%	4.52%	4.52%
85	3.54%	4.02%	4.02%
89	1.18%	2.89%	1.13%
90	1.23%	0.43%	0.43%
91/95	2.15%	3.04%	3.04%
92	4.53%	5.56%	5.56%

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT NO. ICNU/301

REVENUE REQUIREMENT DETAIL

SUMMARY OF ICNU REVENUE REQUIREMENT ADJUSTMENTS
($000)

Line	Adj. No.	Description	Rate Base	Pre Tax NOI	NOI	ROR	Rev. Conv. Factor	Rev. Def. / (Suff).	Delta Cum.
1		Company Filing	4,594,053	163,475	284,665	7.46%	0.580949	99,897	
2	IN-1	Cost of Capital (Gorman)	4,594,053	163,475	284,665	7.15%	0.580949	75,799	(24,098)
3	IN-2	State Tax Rate	4,594,053	163,475	284,665	7.15%	0.582191	75,637	(24,260)
	Adjustments								
4	IN-3	Budgeted Staffing and Capital Levels	(84,325)	5,000	3,010	7.15%	0.582191	(15,533)	
5	IN-4	Depreciation Expenses	-	36,112	21,739	7.15%	0.582191	(37,340)	
6	IN-5	Medical Benefits Expense	-	7,191	4,329	7.15%	0.582191	(7,435)	
7	IN-6	Other Revenues	-	160	96	7.15%	0.582191	(165)	
8	IN-7	ADIT - Production Tax Credit Carryforward	(60,019)	-	-	7.15%	0.582191	(7,376)	
9	IN-8	ADIT - Minimum Tax Credit Carryforward	(7,239)	-	-	7.15%	0.582191	(890)	
10	IN-9	ADIT - Deferred Broker Settlements	(4,666)	-	-	7.15%	0.582191	(573)	
11	IN-10	ADIT - Accrued Incentives	(3,516)	-	-	7.15%	0.582191	(432)	
12	IN-11	ADIT - Stock Incentive Plan	(4,487)	-	-	7.15%	0.582191	(551)	
13	IN-12	ADIT - Accrued Vacation	(6,784)	-	-	7.15%	0.582191	(834)	
14	IN-13	ADIT - Boardman Biomass Revenues	(1,103)	-	-	7.15%	0.582191	(136)	
15	IN-14	Interest Synchronization	-	-	(928)	7.15%	0.582191	1,594	
16		Total Adjustments	(172,139)	48,462	28,246	7.15%	0.582191	(69,673)	
17		ICNU Recommended	4,421,914	211,938	312,912	7.15%	0.582191	5,965	(93,933)
	Other Issues								
18	IN-15	Remove CIO							
19	IN-16	Use 2016 GRC Load Following Method							

Portland General Electric Company, 2018 General Rate Case

Revenue Requirement Calculations

IN-1 -- Cost of Capital

	Company Proposed	M. Gorman Recommended
Cost of Debt	5.17%	5.17%
Cost of Equity	9.75%	9.25%
Capital Structure		
Debt %	50.00%	51.35%
Equity %	50.00%	48.65%
Pre-tax ROR	7.460%	7.155%
Composite Tax Rate	39.93%	39.80%
Post-tax ROR	10.70%	10.13%

Portland General Electric Company, 2018 General Rate Case
Revenue Requirement Calculations

IN-2 -- Revenue Conversion Factor

Line No.	Description	Company Proposed	ICNU Proposed
1	**Revenues**	1.000000	1.000000
	Expense:		
2	Uncollectibles	0.003700	0.003700
3	Commission Fees	0.003750	0.003750
4	Franchise Fees	0.025455	0.025455
6	Total Expense	0.032905	0.032905
7	Net Operating Income Before State Tax	0.967095	0.967095
8	State Income Taxes	0.073328	0.071416
9	Net Operating Income before State Taxes	0.893768	0.895679
10	Federal Income Tax	0.312819	0.313488
11	REVENUE CONVERSION FACTOR	0.580949	0.582191

	Tax Rate Comparison	Per Rate Filing	Per 2016 10-K at 108
12	Federal Tax Rate	35.00%	35.00%
13	Blended State Tax Rate	7.58%	7.38%
14	State Tax Rate With Federal Benefit	4.93%	4.80%
15	Effective	*39.93%*	*39.80%*
	Check	*0*	*0*

Portland General Electric Company, 2018 General Rate Case

Revenue Requirement Calculations

IN-3 -- Depreciation Adjustment Calculation
($000)

Description	Company Proposed	ICNU Opening	Adjustment
Depreciation Expense	328,386	299,600	
Asset Retirements	7,325	-	
Adj. Declining Balance	(12,336)	(12,336)	
Remove Bdmn Decom	(5,877)	(5,877)	
Retail	(74)	(74)	
Totals	317,424	281,312	(36,112)

Notes:

(1) Assumed no rate base impact due to use of beginning of year rate base balances, which would not be impact by lower depreciation expenses in the test period.

Portland General Electric Company, 2018 General Rate Case

Revenue Requirement Calculations

IN-5 -- Medical Benefits Expense Adjustment Calculation
($000)

	Company Proposed Increase			ICNU Proposed Increase		
	9260004	9260005		9260004	9260005	
Description	Union	Non-Union	Total	Union	Non-Union	Total
Outside Services	(233)	153	(80)	(233)	153	(80)
2016 Actual to Budget Results	71	351	423	-	-	-
2017 Med. Premium Esc.	1,696	410	2,106	1,696	410	2,106
2017 Incremental FTE	1,645	657	2,301	822	328	1,151
2017 Other Premium Esc.	96	-	96	96	-	96
2018 Premium Esc.	2,494	909	3,403	-	-	-
2018 Incremental FTE	346	-	346	-	-	-
Inflation Escalation	1,017	435	1,452	-	-	-
Change in Retiree Medical	304	112	416	-	-	-
Total Budgeted Increase	**7,436**	**3,027**	**10,464**	**$ 2,381**	**$ 892**	**3,273**
					Adjustment:	**7,191**

Portland General Electric Company, 2018 General Rate Case

Revenue Requirement Calculations

IN-7 - IN-13 -- Accumulated Deferred Income Tax Adjustments
($000)

Adj. No.	ADIT Item	Company Proposed	ICNU Opening	Adjustment
IN-7	Production Tax Credit Carryforw	60,019	-	(60,019)
IN-8	Minimum Tax Credit Carryforwa	7,239	-	(7,239)
IN-9	Deferred Broker Settlements	3,244	(1,422)	(4,666)
IN-10	Accrued Incentives	7,032	3,516	(3,516)
IN-11	Stock Incentive Plan	4,487	-	(4,487)
IN-12	Accrued Vacation	6,784	-	(6,784)
IN-13	Boardman Biomass Revenues	1,103	-	(1,103)
	Totals	89,907	2,093	(87,814)

Notes:

(1) See the Company's Response to ICNU Data Request 64 for an explanation of each of these items.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT NO. ICNU/302

2018 BUDGET VERSUS 2016 ACTUAL RESULTS

2018 Budget versus 2016 Actual Results

Account	Description	2016 Actuals	2018 Forecast	Delta
ADMIN_&_OTHER				
9020001	CustAcct-Meter Reading Exp.	673,600	243,604	(429,996)
9030001	CustAcct-CustRecords&Collect	45,013,372	58,827,451	13,814,079
9040001	CustAcct-UncollectAcctsExpense	5,152,432	7,326,329	2,173,897
9050001	CustAcct-MiscCustomerAcctsExp	5,595,059	6,927,238	1,332,179
9080001	CustSvc-CustomerAssistanceExp	12,176,505	14,328,451	2,151,946
9090001	CustSvc-InformAdvertisingExp	2,015,784	2,034,762	18,978
9200001	A&G-Wages&Salaries(Allocable)	18,039,344	20,010,034	1,970,690
9200002	A&G-Wages&Salaries(Non-Alloc)	20,568,702	21,246,408	677,706
9200004	A&G-NotableAchievementAwards	1,426,707	661,500	(765,207)
9200005	A&G-Corporate Incentive Plan	8,660,635	12,552,202	3,891,567
9200006	Officer Incentive & ACI Plans	5,449,085	6,939,508	1,490,422
9200007	A&G-Stock Incentive Plan	5,604,190	7,336,011	1,731,821
9200008	Coy Spr/Pt West/Biglow Incents	1,629,846	1,573,962	(55,884)
9200009	A&G-Support Emp/Labor Relation	874,238	1,117,665	243,427
9200010	A&G-Loss Prevention	794,793	533,169	(261,624)
9200012	A&G - Miscellaneous Awards	75,114	-	(75,114)
9200013	Perf Incent Compen - Non-Alloc	1,997,796	6,452,112	4,454,316
9200015	A&G-Record&InfoMgt	795,149	977,049	181,900
9200017	Incentive Labor Loading Offset	(4,098,935)	(6,140,394)	(2,041,459)
9210001	A&G-NonLabor Exp-Allocable	11,019,391	12,679,578	1,660,188
9210002	A&G-NonLabor Exp-Nonalloc	9,225,689	11,178,413	1,952,724
9210009	OfficeSupp&Exp-EmpLaborRelatio	340,763	96,253	(244,511)
9210010	OfficeSupp&Exp-Loss Prevention	140,163	799,576	659,413
9210011	OfficeSupp&Exp-A&GNonAllcToCS2	(285,136)	9,102	294,237
9210013	OfficeSupp&Exp-SunwayAdminFees	-	-	-
9210015	OfficeSupp&Exp-Record&InfoMgmt	54,191	141,422	87,231
9210016	Conversion-EmploySupportOffset	(530,641)	(481,915)	48,726
9210018	Outside Accounting Fees	60	-	(60)

2018 Budget versus 2016 Actual Results

Account	Description	2016 Actuals	2018 Forecast	Delta
9210900	SSHG Interco Charge Utility	794,728	564,148	(230,581)
9220001	AdminExpenseTransferred-Credit	(10,284,696)	(11,920,034)	(1,635,338)
9230001	Outside Services Employed	11,863,068	5,769,466	(6,093,602)
9230002	Outside Services - Allocable	39,404	-	(39,404)
9240001	Property Insurance Expense	5,444,257	6,262,083	817,827
9250001	Injuries&Damages Expense	2,760,539	2,004,666	(755,873)
9250002	Injury&Damages-Unallocated	55,231	17,196	(38,036)
9250003	Injury&Damages-Allocated	5,509,124	7,005,292	1,496,167
9250004	Injuries & Damages Offset	(3,902,005)	(4,264,967)	(362,963)
9260001	BenefitExp-Pension Plan	22,829,424	27,688,000	4,858,576
9260003	BenefitExp-PostRetireLifeUnion	910,791	1,424,486	513,695
9260004	Benefit Exp - Medical Union	12,177,759	15,205,205	3,027,446
9260005	Benefit Exp - Medical NonUnion	28,370,465	35,806,690	7,436,225
9260006	BenefitExp-SERP	1,456,093	1,435,000	(21,093)
9260007	BenefitExp-MDCP	5,494,982	4,692,000	(802,982)
9260008	BenefitExp-HRA Union	2,197,571	3,121,009	923,439
9260009	BenefitExp-HRA Non Union	851,614	1,104,142	252,528
9260010	BenefitExp-Paid Time Off (PTO)	34,857,170	43,220,248	8,363,078
9260011	BenefitExp-STD Insurance	588,903	706,303	117,400
9260012	BenefitExp-Vac&LeaveLoading	(36,328,962)	(43,220,248)	(6,891,287)
9260014	BenefitExp-EducationProgram	223,528	491,479	267,951
9260015	Employee Benefits Loading	(29,740,472)	(38,963,730)	(9,223,258)
9260016	BenefitExp-MiscEmployeeBenefit	251,233	895,133	643,901
9260018	BenefitExp-EmployeeWellness	745,163	779,600	34,438
9260019	BenefitExp-EmployeeAssistance	162,813	55,473	(107,340)
9260020	BenefitExp-AdminsterPrograms	1,624,539	1,463,156	(161,383)
9260021	BenefitExp-LongTermDisability	1,725,830	2,084,959	359,130
9260022	BenefitExp-Savings Plan	18,625,065	22,834,170	4,209,105
9260024	Pension Svc Cost Offset	(644,537)	(708,610)	(64,073)

2018 Budget versus 2016 Actual Results

Account	Description	2016 Actuals	2018 Forecast	Delta
9260025	Net Periodic Pensn Cost Offset	(9,004,867)	(7,551,911)	1,452,956
9280001	Regulatory Commission Expense	976,412	1,452,239	475,827
9280002	RegCommExp-FERC Fees	6,015,710	6,261,264	245,554
9280003	RegCommExp-FERCSalesforResale	669,232	669,232	-
9280004	RegCommExp-RES Compliance	46,855	-	(46,855)
9290001	DuplicateChargesOffset-Credit	(2,254,488)	(2,300,448)	(45,960)
9301001	GenAdvertisExp-CorpImage Adver	538,053	707,617	169,564
9302001	MiscGenExp-A&G Misc Expenses	6,301,545	7,829,408	1,527,863
9302002	MiscGenExp-Dir Pen & DDCP	116,922	54,800	(62,122)
9302003	MiscGenExp-Invol Severance Prg	1,589,637	1,308,385	(281,252)
9302004	MiscGenExp-Dir Fees & Exps	2,446,090	2,694,062	247,972
9302005	MiscGenExp-StkIncentiPlanDirec	822,727	960,000	137,273
9302006	Commercial Paper Fac Fees	184,595	113,421	(71,174)
9310001	Rents - General Facilities	4,875,592	5,594,169	718,577
	ADMIN_&_OTHER Total	**244,390,537**	**290,714,044**	**46,323,506**
DEPR_&_AMORTIZATION				
4030001	Depreciation Expense	266,415,570	328,386,470	61,970,900
4031001	DeprecExp-Asset Retirement	7,087,268	7,325,173	237,905
4040001	Amort Limted Term Elect Plant	44,097,840	56,293,680	12,195,840
4070001	Amort Of UnrecvPlt-Troj Decomm	(12,840,313)	(13,811,659)	(971,346)
4073001	Regulatory Debits	13,760,743	8,789,042	(4,971,701)
4074001	Regulatory Credits	(2,761,243)	(200,000)	2,561,243
4111099	Accretion Expense	3,259,305	-	(3,259,305)
4117001	Loss From Disposal of Property	(35,338)	-	35,338
	DEPR_&_AMORTIZATION Total	**318,983,831**	**386,782,706**	**67,798,875**
PRODUCTION_&_DISTRIB				
5000001	StmOp-OpsSupervision&Engineer	2,856,938	3,052,735	195,797

2018 Budget versus 2016 Actual Results

Account	Description	2016 Actuals	2018 Forecast	Delta
5010010	StmOp- Fuel - Fuel Handling	3,777,636	6,384,628	2,606,992
5020001	StmOp- Steam Expenses	6,831,410	6,170,562	(660,847)
5060001	StmOp- Miscellaneous Expenses	8,121,087	8,955,425	834,338
5060002	StmOp-MiscExp-General Plt Supp	310	26,332	26,022
5070001	StmOp-Rents	42,262	40,123	(2,139)
5100001	StmMaint-MaintSupvEng	950,845	1,850,325	899,479
5110001	StmMaint-MaintOfStructures	1,094,274	303,786	(790,488)
5120001	StmMaint-MaintOfBoilerPlant	7,497,261	3,662,004	(3,835,257)
5130001	StmMaint-MaintOfElectricPlant	12,383,171	19,426,141	7,042,970
5140001	StmMaint- Miscell. Steam Plant	1,341,286	1,881,016	539,731
5350001	HydrOp-GenOperSupervEngineer	865,203	909,870	44,668
5360001	HydrOp-WaterForPwr-Purch Water	568,105	597,435	29,331
5370001	HydrOp- Hydraulic Expenses	2,044,708	2,580,143	535,434
5370002	Hydraulic Expense FishWildlife	3,398,708	3,111,957	(286,751)
5370003	Hydraulic Expense Parks	1,465,089	1,802,309	337,220
5380001	HydrOp-Electric Expenses	1,230,715	1,553,850	323,135
5390001	HydrOp- Miscellaneous Expenses	3,049,632	2,603,790	(445,842)
5400001	HydrOp- Rents Hydraulic	672,782	731,486	58,704
5410001	HydrMaint-MaintSupvEng	796,023	918,392	122,369
5420001	HydrMaint-MaintOfStructures	137,894	-	(137,894)
5430001	HydrMaint-MaintResvDamsWaterwy	1,871,508	207,668	(1,663,840)
5440001	HydrMaint-MaintOfElectricPlant	1,309,814	2,454,657	1,144,844
5450001	HydrMaint-MaintofMiscHydroPlnt	833,666	839,140	5,474
5450002	Hydraulic Expense Fish	362,927	72,313	(290,613)
5450003	Hydraulic Expense Parks	57,344	29,270	(28,074)
5460001	OthGenOp-OpsSupervisonEngineer	3,820,585	3,809,966	(10,619)
5470182	OthGenOp-CapLseFuel-Opex	1,416,666	3,222,069	1,805,403
5480001	OthGenOp-Generation Expenses	7,064,413	11,154,141	4,089,727
5490001	OthGenOp-Miscellaneous Expense	12,715,658	11,495,352	(1,220,306)

2018 Budget versus 2016 Actual Results

Account	Description	2016 Actuals	2018 Forecast	Delta
5500001	OthGenOp-RentsOtherProduction	1,135,286	1,172,879	37,593
5510001	OthGenMaint-MaintSupvEng	725,649	563,999	(161,650)
5520001	OtherProd - Maint of Structure	692,528	743,923	51,395
5530001	OthGenMaint-Gen&ElectricPlant	40,364,586	49,112,944	8,748,358
5540001	OthGenMaint-Other Gen Plant	1,017,793	1,355,322	337,529
5540002	OthGenMaint-QualifyFacilCharge	-	-	-
5560001	PwrSuppExp-SysContrDispatElect	52,886	(1,810,425)	(1,863,311)
5570001	PwrSuppExp-Power Operations	14,480,195	17,682,677	3,202,482
5570002	PwrSuppExp-OpsSupvEngineering	35,400	-	(35,400)
5570003	PwrSuppExp-Miscellaneous Exp	4,559,125	4,455,845	(103,280)
5600001	TransOp-OpSupv&Engineering	4,855,984	3,605,377	(1,250,607)
5600003	TransOp-IntercoTransStudyRev	889	-	(889)
5600038	Transmisison Ops - Non Alloc	-	1,625,811	1,625,811
5611001	Load dispatch - Reliability	12,519	200,948	188,429
5612001	TransOp-Load Disp Monitor&Oper	587,600	462,245	(125,355)
5613001	TransOp-Load Disp Transmission	1,204,546	1,585,640	381,094
5615001	TransOp-ReliabilityPlaning&Std	11,450	-	(11,450)
5616001	TransOp-TransmissionServ Study	-	-	-
5617001	TransOp-GenerationInterconStdy	173	105,589	105,416
5620001	TransOp-Station Exp-PGE Trans	128,451	29,108	(99,343)
5630001	TransOp-OH Line Exp 500kV	22,366	-	(22,366)
5630002	TransOp-OH Line Exp 230kV	1,718	-	(1,718)
5640001	TransOp-Underground Line Exp	-	-	-
5670001	TranOp-Rents-500KVTransmission	2,441,543	2,754,005	312,463
5670002	TranOp-Rents-230KVTransmission	161,700	9,307	(152,393)
5680001	TranMaint-Supv&Engineering	42,953	33,556	(9,398)
5692001	TranMaint-MaintComputerSoftwar	771,530	1,287,794	516,264
5700001	TranMaint-Substation Equip	1,818,551	1,275,303	(543,248)
5710001	TranMaint-O/HLine-500KvLine	298,071	724,147	426,076

2018 Budget versus 2016 Actual Results

Account	Description	2016 Actuals	2018 Forecast	Delta
5710002	TranMaint-O/HLine-230KvLine	189,561	545,914	356,353
5710003	TranMaint-O/HLine-Faraday	854	-	(854)
5730001	TranMaint - Misc Trans Plnt	124	-	(124)
5800001	DistOp-Engineering & Design	15,091,102	17,292,934	2,201,832
5800002	DistOp-OpSupv-General Support	48,917,101	69,373,807	20,456,706
5800999	DistOp-OpSupvEng-DOSE Offset	(42,128,709)	(56,646,560)	(14,517,851)
5810001	DistOp-Load Dispatching	1,827,184	1,645,545	(181,639)
5820001	DistOp-Substation Exp	1,149,199	610,441	(538,758)
5821001	DistOp-Enrgy Storage Equip	-	-	-
5830001	DistOp-Overhead Line Exp	3,101,422	1,497,886	(1,603,536)
5840001	DistOp-Underground Line Exp.	4,889,367	3,546,464	(1,342,903)
5841001	DistOp-Enrgy Storage Equip	1,115	-	(1,115)
5850001	DistOp-StLgtExp-Street Lights	576,268	103,110	(473,158)
5850002	DistOp-StLgtExp-Area Lights	169,640	-	(169,640)
5860001	DistOp-Meter Expenses	2,886,772	2,601,197	(285,575)
5870001	DistOp-CustomerInstallationExp	3,786,067	2,171,086	(1,614,981)
5880001	DistOp-Misc Distribution Exp.	7,769,194	3,150,833	(4,618,361)
5890001	DistOp-Rents Expense	1,597,954	2,089,732	491,778
5900001	DistMaint-Supv&Engineering	45,062	-	(45,062)
5910001	DistMaint-Maint of Structures	131,768	-	(131,768)
5920001	DistMaint-Substation Equip	4,424,560	6,725,623	2,301,064
5922001	DistMaint-Enrgy Storage Equip	9,666	-	(9,666)
5930001	DistMaint-Overhead Lines	42,841,925	40,286,720	(2,555,205)
5940001	DistMaint-Underground Lines	6,891,835	6,607,576	(284,259)
5950001	DistMaint-Line Transformers	2,034,995	3,558,817	1,523,822
5960001	DistMaint-Street Lights	1,071,417	1,394,074	322,657
5960002	DistMaint-Area Lights	-	-	-
5970001	DistMaint-Meters	80,033	1,526,121	1,446,089
5980001	DistMaint-MiscDistribPlant	9,446,556	11,151,942	1,705,387

2018 Budget versus 2016 Actual Results

Account	Description	2016 Actuals	2018 Forecast	Delta
9350001	Maintenance of General Plt	2,706,940	3,002,851	295,910
	PRODUCTION_&_DISTRIB Total	**283,510,379**	**309,058,993**	**25,548,613**
TAX_OTHER_THAN_INC				
4081001	TaxOthThan IncTax-PropTax-Oreg	51,439,840	51,974,649	534,809
4081002	TaxOthThan IncTax-PropTax-Wash	1,640,162	2,059,752	419,590
4081003	TaxOthThan IncTax-PropTax-MT	5,752,457	6,003,312	250,855
4081004	TaxOthThanIncTax-PyrllTax-FICA	19,895,195	27,865,905	7,970,710
4081005	TaxOthThanIncTax-FedUnemploymt	130,491	175,260	44,769
4081006	TaxOthThan IncTax- Tri - Met	1,547,562	1,962,581	415,019
4081007	TaxOthThanIncTax-State Unempl	1,693,884	2,978,917	1,285,033
4081008	TaxOthThanIncTax-WorkComp-SIAC	242,538	315,415	72,877
4081009	TaxOthThanIncTax- O.H. Distrib	(9,987,046)	(14,543,794)	(4,556,748)
4081010	TaxOthThanIncTax-FranFeePort	13,925,241	14,526,271	601,030
4081011	TaxOthThanIncTax-FranFeeOthCit	29,200,145	29,020,236	(179,909)
4081012	TaxOthThanIncTx-ForInsrExcisTx	9,485	-	(9,485)
4081013	TaxOthThanIncTx-MiscTax&Lic-OR	1,995,850	1,971,706	(24,144)
4081014	TaxOthThanIncTx-MiscTax&Lic-MT	407,253	462,504	55,251
5470183	OthGenOp-CapLseFuel-UPropTaxOr	319,728	717,324	397,596
	TAX_OTHER_THAN_INC Total	118,212,785	125,490,038	7,277,254
OTHER_OPERATING_REV				
4470003	SalesfrResale-IntertiePGEtoPGE	(5,936,823)	(5,934,000)	2,823
4500001	Forefeited Discounts	(2,994,617)	(2,900,000)	94,617
4510001	Miscellaneous Service Revenues	(1,852,377)	(1,905,392)	(53,015)
4530001	Sales of Water & Water Power	24,166	-	(24,166)
4540001	Rent From Electric Property	(1,025,319)	(1,217,728)	(192,409)
4540002	RentFrElecProperty-Joint Pole	(7,679,162)	(6,279,394)	1,399,768
4560001	Other Electric Revenues	(3,648,451)	(2,973,166)	675,285

2018 Budget versus 2016 Actual Results

Account	Description	2016 Actuals	2018 Forecast	Delta
4560003	OthElecRev-FishWildlifeRecrOps	(12,386)	(16,002)	(3,616)
4560005	OthElecRev-Utility Non-Kwh	(2,478)	-	2,478
4560007	OthElecRev-TransmissionResale	(7,002,705)	(5,124,600)	1,878,105
4560008	OthElecRev-Gas for Resale	(1,270,178)	-	1,270,178
4560010	OthElecRev-TransmissionRevElim	-	-	-
4560011	Oil For Resale Revenue	-	-	-
4560012	OthElecRev-Steam Sales	(1,480,085)	(1,684,211)	(204,126)
4561001	TransRevOthers-Non-Intertie	(2,899,444)	(3,034,800)	(135,356)
4561002	TransRevOthers-Intertie	(5,080,702)	(5,044,000)	36,702
5550001	PurchPwr- Intercompany	-	-	-
5660001	TransOp-Misc Transmission Exp	57,958	57,116	(842)
5660002	TransOp-MiscExp-IntertieWhePGE	5,936,823	6,075,823	139,000
5660003	TransOp-MiscExpNonInterPGE-PGE	49,631,086	48,464,479	(1,166,607)
5660004	TranOp-MiscExpNonIntRevPGE-PGE	(49,631,086)	(47,319,831)	2,311,255
	OTHER_OPERATING_REV Total	(34,865,779)	(28,835,707)	6,030,072

	2016 Actuals	2018 Forecast	Delta
ADMIN_&_OTHER Total	244,390,537	290,714,044	46,323,506
DEPR_&_AMORTIZATION Total	318,983,831	386,782,706	67,798,875
PRODUCTION_&_DISTRIB Total	283,510,379	309,058,993	25,548,613
TAX_OTHER_THAN_INC Total	118,212,785	125,490,038	7,277,254
OTHER_OPERATING_REV Total	(34,865,779)	(28,835,707)	6,030,072
GRAND TOTAL	930,231,753	1,083,210,073	152,978,320

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT NO. ICNU/303

RESPONSES TO ICNU DATA REQUESTS

March 27, 2017

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

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 005
Dated March 13, 2017

Request:

Reference FERC Accounts 9260004 Benefit Exp - Medical Union; 9260005; and Benefit Exp - Medical NonUnion:

a. **Please provide an explanation for why the Company expects the expenses incurred in these accounts to increase by $3.0 million and $7.4 million, respectively, between 2016 and 2018; and,**

b. **Please also provide any and all workpapers necessary to support the increased level of expense for this account in 2018.**

Response:

a. The primary drivers of the increases in accounts 9260004 and 9260005 are (1) increases in medical and dental rates from benefit providers and (2) increases in full-time equivalent employees (FTEs). These drivers are discussed in more detail in PGE Exhibit 400, pages 24-27.

b. Attachment 005-A identifies the increases attributable to each category of cost driver. PGE provided premium data for the test year in OPUC Standard Data Request No. 064. PGE's benefit assumptions are also discussed in OPUC Standard Data Request No. 063.

Active Medical

	2016 Active Medical Actuals	2016 Active Medical Budget	2017 Premium Escalation and Employee Migration to HSA qualified plan
Total Amount	$ 26,687,996	$ 26,759,269	$ 27,492,794
Variance		$ 71,273	$ 733,525

Retiree Medical

	2016 Actuals	2017 Budget	2018 Budget
Total Amount	$ 1,449,069	$ 1,542,000	$ 1,753,000
Variance		$ 92,931	$ 211,000

Summary

Description	Amount
Outside Services	$ (233,400)
2016 Actual to Budget Results	$ 71,273
2017 Premium Escalation and Employee Migration to HSA qualified plan	$ 733,525
2017 Incremental FTE	$ 2,215,098
2017 Dental, Vision and LTD premium esclation	$ 488,371
2018 Premium Escalation and Employee Migration to HSA qualified plan	$ 2,494,316
2018 Incremental FTE	$ 346,000
Inflation Escalation	$ 1,017,111
Change in Retiree Medical	$ 303,931
Total	**$ 7,436,225**

2017 Incremental FTE	2017 Dental, Vision and LTD premium esclation	2018 Premium Escalation and Employee Migration to HSA qualified plan	2018 Incremental FTE	Inflation Escalation
$ 29,707,892	$ 30,196,263	$ 32,690,579	$ 33,036,579	$ 34,053,690
$ 2,215,098	$ 488,371	$ 2,494,316	$ 346,000	$ 1,017,111

Active Medical

	2016 Actuals	2016 Budget
Total Amount	$ 11,649,866	$ 12,001,167
Variance		$ 351,301

Retiree Medical

	2016 Actuals	2017 Budget
Total Amount	$ 262,815	$ 304,000
Variance		$ 41,185

Summary

Description	Amount
Outside Services	$ 153,135
2016 Actual to Budget Results	$ 351,301
2017 Premium Escalation	$ 410,418
2017 Incremental FTE	$ 656,697
2018 Premium Escalation	$ 908,969
Inflation Escalation	$ 434,743
Change in Retiree Medical	$ 112,185
Total	**$ 3,027,448**

2017 Premium Escalation	2017 Incremental FTE	2018 Premium Escalation	nflation Escalatior
$ 12,411,585	$ 13,068,282	$ 13,977,251	$ 14,411,994
$ 410,418	$ 656,697	$ 908,969	$ 434,743

2018 Budget
$ 375,000
$ 71,000

March 27, 2017

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

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 027
Dated March 13, 2017

Request:

Reference FERC Account 4560001, Other Electric Revenues:

a. **Please provide a general description of the revenues recognized in this account;**

b. **Please provide an explanation for why the Company expects the revenues recognized in this account to decline by $0.7 million (a 19% reduction) between 2016 and 2018;**

c. **Please provide invoice-level detail from the Company's accounting system supporting the $3.6 million of revenue recognized in this account in 2016; and,**

d. **Please provide workpapers containing detailed calculations supporting the Company's proposed forecast of $3.0 million for this account in 2018.**

Response:

a. The revenues recognized in this account are derived from electric operations not included in other FERC accounts. The primary components of this account include revenues from the Energy Trust of Oregon for the energy efficiency contract with PGE (see PGE's response to OPUC Data Request No. 138) and receipts for park services at PGE facilities (primarily hydro).

b. The $0.7 million variance between 2016 and 2018 is primarily due to revenues from Energy Trust Energy Efficiency efforts, OHSU maintenance reimbursements, and Net Metering Schedules, described as follows:

- From 2016 to 2018, energy efficiency revenues from the Energy Trust of Oregon (ETO) are projected to decrease by approximately $200,000. This is largely due to changes in the contract with the ETO that included lower expected revenues compared to 2016 actuals. Please note, the contract revenue number and 2018 forecast differ due to the contract not being complete and finalized when the 2018 forecast was established. For a copy of the PGE/ETO contract, see PGE's responses to the following:
  - OPUC Data Request No. 138, Attachments 138-A, 138-B, and 138-C; and
  - OPUC Data Request No. 128, Attachments 128-D.

- From 2016 to 2018, revenues from OHSU are projected to decrease by approximately $200,000 because PGE inadvertently omitted $160,000 of revenue from this budget.

- From 2016 to 2018, revenues from Qualifying Facilities Schedule 201 and Net Metering Schedule 203 are projected to decrease by approximately $200,000. Schedule 201 is a Purchase Power Agreement (PPA) tariff for qualifying facilities (QFs) selling power to PGE. The revenue is for the qualifying process for the potential QF permitting, developing and study work. Schedule 203 is revenue from interconnection reviews and applications. Both these revenue streams are unpredictable as it is not known when, if, and/or how many requests PGE will receive in a given year. Thus, there is no 2018 forecast for these potential revenue streams, resulting in a decrease in revenue from 2016 actuals to the 2018 forecast.

c. Attachment 027-A provides the requested information. Attachment 027-A is protected information and subject to protective Order No 17-057.

d. As noted in PGE's response to OPUC Data Request No. 128, Attachment 128-A, rows 24-26, PGE forecasts amounts for account 4560001 as follows:

- Park revenue is from visitors renting/reserving campgrounds, day use fees, firewood sales, as well as concessionaire rental fees. The 2018 forecast was based on 2016 actuals with minor reductions for parks being closed during construction work at campgrounds in 2018.
- Energy Trust – PGE and Energy Trust have an agreement of expected revenues related to energy efficiency. The 2018 forecast is largely based on the signed agreement between PGE and Energy Trust (see Attachment 128-D). Please note, the contract revenue number and 2018 forecast differ due to the contract not being fully finalized when the 2018 forecast was determined.
- Disbursements & Receivables - Revenue related to cash rebates PGE receives from the use of credit cards. PGE employees are issued company credit cards also known as Procurement Cards (P-Cards) to use for business expenses. Similar to many other credit card plans, PGE gets a percentage rebate or "cash back" for all transactions

from the use of these P-Cards. The 2018 forecast was closely based on the 2016 actuals as the expectation for P-Card usage in 2018 was expected to be similar to the activity experienced in 2016.

April 18, 2017

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

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 031
Dated April 4, 2017

<u>Request:</u>

Please provide a narrative explanation of the methodologies employed by the Company to develop its budgets for the rate years. Please also provide any documents which contain formalized policies and procedures that govern the budgeting process the Company uses.

<u>Response:</u>

Attachment 031-A is a presentation provided to OPUC Staff on January 29, 2015, regarding PGE's budgeting and forecasting processes. As shown on slides 2 and 3, and further explained on the subsequent slides, the planning process of developing a Statement of Direction, Operating Assumptions, Capital Expenditure Plan, and Capital and Operating Expense targets are the precursor to developing an operating budget for the upcoming year, which ensures alignment between the budget and PGE's strategic intent. Developing the operating budget typically begins in July and concludes in October. Attachment 031-B is PGE's 2017 Budget Instruction Manual which details the budget process.

The budget is developed in two parts: 1) the operating budget, and 2) the capital budget. The Corporate Planning Department is responsible for sending out the "call memo" for next year's budget. The first step is developing the capital budget. Usually in May, the capital call memo is sent to all department managers to request they submit capital requests. A funding project document is submitted and describes the scope and cost of the project and any economic, regulatory and/or other consequences of doing or not doing the project. Attachment 031-C is PGE's corporate policy on Project Authorization. The submitted projects are reviewed and approved by PGE's Capital Review Group and finally the Board of Directors.

In July, Corporate Planning sends the O&M Budget Call. The operating budgets are input into the PowerPlan system and reviewed by department managers, the Corporate Planning Department, and by each functional vice president. The Board of Directors performs the final review and approval for both the capital and operating budgets. Attachment 031-D is a presentation made to OPUC Staff during a pre-rate case audit in late 2013 (prior to Docket No. UE 283, PGE's 2015 general rate case) that further details the development of PGE's labor budget.

April 18, 2017

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

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 036
Dated April 4, 2017

Request:

Reference "ICNU_DR_005_Attach A":

a) **Please provide workpapers supporting the hardcoded numbers on Excel Rows 5, 10, and 17 in Tabs "Non-Union" and "Union" in the referenced workbook.**

b) **Please identify the premium escalation assumed for each benefit plan and for each year to develop the rate year forecast of benefits expense.**

c) **Please provide all relevant information relied upon by the Company to support the premium escalation assumptions for each benefit plan and for each year to develop the rate year forecast of benefits expense.**

d) **In Tab "Non-Union," please explain why an additional inflationary adjustment in Excel Column J is appropriate and necessary, given that the Company already accounts for the year-over-year escalation in premiums in Excel Columns E, G, and H.**

e) **Please provide an explanation for how the migration of employees to Health Savings Account qualified plans impacts benefit costs to the Company.**

f) **Please provide an explanation for why it is appropriate to include the 2016 variance between budgeted and actual benefits expense as a component of the Company's rate year benefits expense.**

Response:

a) Attachments 036-A and 036-B are workpapers supporting the increases attributable to each category of cost driver for 2018 non-union and union active medical costs. During review of the workpapers for non-union medical, PGE identified an error in its calculation of the amounts originally reported in cells E5 and F5 within its response to ICNU DR No. 005, Attachment 005-A (See worksheet labeled "Non-Union").

- Cell E5 excluded medical and dental costs associated with non-union employees who have main bargaining unit medical plan coverage.
- Cell F5 included costs associated with incremental FTE for only medical coverage. Cell F5 did not include the cost impacts of dental, vision and LTD.

Attachment 036-A reports the correct variance amounts by category, and PGE has supplemented its response to ICNU DR No. 005 to correct the error.[1] Total budget amounts were not impacted.

Attachment 036-C is a workpaper supporting the cost drivers for the 2018 non-union and union retiree medical costs.

Note: There is no workpaper for the entry in the category "Outside Services". The entry reflects the remaining variance between 2016 actuals and 2018 budget after other categories of cost drivers have been accounted for.

Attachment 036-D is a list of account entries that support the "2016 Actuals" reported in PGE's response to ICNU Data Request No. 005.

b) Premium escalations for union medical plans are part of Attachment 036-B and include:

- 2016 Budget: See Attachment 036-B, cell D6.[2]
- 2017 Budget: 2% escalation of actual 2016 premium.
- 2018 Test Year: 7% escalation of 2017 Budget.

Premium escalations for non-union medical plans are part of Attachment 036-A. In general, escalation rates are reported under worksheet sublabels: MEDICAL, DENTAL, VISION, and LTD. Note that 2016 and 2017 premium escalations are actual premiums, not estimates.

c) As noted in part b of this response, 2016 and 2017 premiums are actuals, not estimates. As described on page 25 of PGE Exhibit 400, PGE's benefits consultant, Mercer, provides PGE with forecasted premium increases for the 2018 forecast.

---

[1] There are also slight differences (less than 0.001%) in amounts originally reported in cells G5 and I5.
[2] Please see PGE's Response to OPUC Standard DR 067, confidential Attachment 067-D for the actual 2016 rate.

Attachment 037-E is a workpaper showing the trend guidelines used by Mercer when providing premium escalation estimates for Active Medical, Dental and Prescription Drug plans. As an example, Mercer's estimate of 7% for PGE in 2018 (i.e., Active Medical) is within the range identified by Mercer (i.e., 4.5% to 9.00%). Mercer pairs its trending data with PGE's employee demographics and usage trends in order to calculate the customized forecast of 7.0% for PGE. See also PGE's Responses to OPUC Data Request No. 305. Based on recent benchmarking, PGE's total medical costs per covered employee were substantially lower than the industry benchmark.

d) PGE inadvertently included the inflation escalation, and will identify the need to remove the inflation escalation from its test year forecast in PGE Reply Testimony.

e) See PGE's Response(s) to OPUC Data Request No. 302.

f) PGE used its 2016 budget forecast as a beginning basis for its 2017 and 2018 medical cost estimates. Therefore, the variance in budget-to-actual is a contributor to the explanation of differences between 2016 actuals and PGE's 2018 test year forecast (i.e., ICNU Data Request No. 005). PGE's forecasts for 2017 and 2018 medical costs occur prior to year-end 2016, and so long as 2016 actuals are tracking close to 2016 budget, the use of the 2016 budget forecast is a reasonable and readily available basis for forecasting 2017 and 2018 medical costs. As shown in PGE's Response to ICNU DR 005, PGE's actual, active medical costs were $71,273 (or 0.3%) different from budget (i.e., a reasonable difference).

Attachments 036-A, 036-B, 036-C, and 036-E are protected information subject to Protective Order No. 17-057.

April 27, 2017

TO:

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU Data Request No. 0064
Dated April 13, 2017

<u>Request:</u>
Reference PGE/200 workpaper "2018 Deferred tax Detail.xlsx", Tab "Summary Ms and ADIT":

a. **Please identify and describe the purpose of Excel Row 8, titled "Beginning Balance Adjustment."**
b. **Please provide workpapers supporting the hard-coded values in Excel Range "D8:E8."**
c. **Please provide workpapers supporting the hard-coded values in Excel Range "G19:I23."**
d. **Please provide workpapers supporting the hard-coded values in Excel Rage "G27:I27."**
e. **Please provide historical domestic production activities deduction for the period 2013-2016.**
f. **Please provide workpapers supporting the hard-coded values in Excel Range "G31:I36."**
g. **Please provide workpapers supporting the hard-coded values in excel Range "C37:E37."**
h. **Please describe the purpose of the line item titled "Orion Contingent Royalty Payments" detailed on Row 86 and provide workpapers supporting the hard-coded accumulated deferred tax values associated with that line item.**
i. **Please describe the purpose of the line item titled "AMT Credit C/F" detailed on Row 83 and provide workpapers supporting the hard-coded accumulated deferred tax values associated with that line item.**
j. **Please describe the purpose of the line item titled Brdmn Plant – Fire Boiler w/ Biomass" detailed on Row 77 and provide workpapers supporting the hard-coded accumulated deferred tax values associated with that line item.**
k. **Please identify and describe the purpose of the line item titled "A/P Accrued Incentives" detailed on Row 72 and provide workpapers supporting the hard-coded accumulated deferred tax values associated with that line item.**
l. **Please identify and describe the purpose of the line item titled "DT Reach Environmental Remediation Deferral" detailed on Row 71 and provide workpapers**

supporting the hard-coded accumulated deferred tax values associated with that line item.

m. Please identify and describe the purpose of the line item titled "AccumProv For Injuries&Damages" detailed on Row 57 and provide workpapers supporting the hard-coded accumulated deferred tax values associated with that line item.

n. Please identify and describe the purpose of the line item titled "Stock Incentive Plan RMGMT" detailed on Row 56 and provide workpapers supporting the hard-coded accumulated deferred tax values associated with that line item.

o. Please identify and describe the purpose of the line item titled "Deferred Broker Settlements" detailed on Row 54 and provide workpapers supporting the hard-coded accumulated deferred tax values associated with that line item.

p. Please identify and describe the purpose of the line item titled "CET 2014 Deferral" detailed on Row 44 and provide workpapers supporting the hard-coded accumulated deferred tax values associated with that line item.

Response:

a. The purpose of Excel Row 8, titled "Beginning Balance Adjustment" is to adjust the beginning PTC balances to the ones recorded in PGEs books and records. For support see the response to part (b) below.

b. Support for the values in the Excel range "D8:E8" (Beginning balance Adjustment) is as follows:
    1. The beginning balance as included in the 2015 Results of Operations was $34,877,972. This was the amount recorded for the 2015 year-end provision. However, the amount was adjusted when the 2015 tax return was filed to $29,402,584. The difference of $5,475,388 was recorded in September 2016 as a return-to-accrual adjustment.
    2. With the above adjustment, the carryover balance from 2016 was calculated as $42,097,552. The carryover balance reported on the company books and records for December 2016 was $48,562,015. This schedule utilizes amounts from the company's forecast system. The forecast differed from the actual 2016 generation and utilization reported on the company's financial statements. The difference of $6,464,463 was recorded to adjust the carryover balance from 2016 to $48,562,015 as reported in the company's financial statements for December 2016.

c. Attachment 064-A, which is protected and subject to Protective Order No. 17-057, provides support for the hard-coded values in Excel range "G19:I21." These reports from PGE's deferred tax system show the amounts for 2016 and 2017 (color coded blue). The amount for 2018 is assumed to equal the 2017 amount.

   Attachment 064-B provides an amortization schedule that supports the values in Excel range "G22:I22." The amount for 2018 is assumed to equal the 2017 amount.

Attachment 064-D provides the calculation data on actual amounts and supports the values in Excel range “G23:I23.” Due to an inadvertent error in the calculation, the amount shown for 2016 is double the correct amount. The values in 2017 and 2018 are the 2016 amount rounded down. The correct amount for 2016 is $700,000 instead of $1,400,000. PGE plans to correct this error in our rebuttal testimony.

d. Attachment 064-C, which is protected and subject to Protective Order No. 17-057, provides support for the hard-coded values in Excel range “G27:I27.” The amount for 2018 is assumed to equal the 2017 amount.

e. Attachment 064-E, which is protected and subject to Protective Order No. 17-057, provides the historical domestic production activities.

f. Attachment 64-A provides support for the hard-coded values in Excel range “G31:I36.” These reports from PGEs deferred tax system show the amounts for 2016 and 2017 (color coded orange). The amount for 2018 is assumed to equal the 2017 amount.

g. Attachment 064-J, which is protected and subject to Protective Order No. 17-057, provides support for the 2015 balance in Excel range “C37:E37.” Attachment 064-J, line 273, which was the supporting work paper for the 2015 Results of Operations. Attachment 064-K, which is protected and subject to Protective Order No. 17-057, provides the values for 2016 and 2017. The values are in column G of line 323 on each report.

h. In 2006 PGE purchased windfarm assets and development rights from Orion Energy. As a part of that purchase price, PGE agreed to pay contingent royalty payments to Orion. For tax purposes these payments are an allocation to an asset that must be amortized over the remaining amortization period of non-contingent royalty payments. The line item titled “Orion Contingent Royalty Payments” detailed on Row 86 contains the capitalization and amortization of these payments. This value was included in the 2015 Results of Operations. The supporting work paper for this amount is included as Attachment 064-L, which is protected and subject to Protective Order No. 17-057. As we do not track this item in our forecasts we assumed no change to the balance.

i. The line titled “AMT Credit C/F” detailed on line 83 is the Alternative Minimum Tax credit generated in 2008. It has not been utilized to date. The supporting work paper for this amount is Form 8827 that was filed as part of our 2015 tax return and is included as Attachment 064-M, which is protected and subject to Protective Order No. 17-057.

j. The line item titled “Brdmn Plant – Fire Boiler w/ Biomass” detailed on row 77 is the tax effect of revenue collected to cover the costs of a test burn of biomass fuel that is deferred until the test burn occurs. The supporting work paper for this amount is included as Attachment 064-N, which is protected and subject to Protective Order No. 17-057. Since we do not track this item in our forecasts we assumed no change to the balance.

k. Accrued employee incentives are not deductible until paid. The purpose of the line item titled “A/P Accrued Incentives” detailed on Row 72 is to record a tax deferral of accrued incentives or a tax expense for payment of tax incentives. The supporting work paper for this amount is included as Attachment 064-O, which is protected and subject to Protective Order No. 17-057. As we do not track this item in our forecasts, we assumed no change to the balance.

l. Certain environment costs were deferred and amortized per OPUC Order No. 14-422. The line item titled “DT Reach Environmental Remediation Deferral” detailed on Row 71 is the balance at 12/31/2015. The supporting work paper for this amount is included as Attachment 064-P, which is protected and subject to Protective Order No. 17-057. Since we do not track this item in our forecasts, we assumed no change to the balance.

m. The book accrual for injuries and damages is not deductible for tax purposes until a payment is made against the accrual. The line item titled “AccumProv For Injuries&Damages” detailed on row 57 is the accrued deferred tax liability on the accumulated balance in this account. The supporting work paper for this amount is included as Attachment 064-Q, which is protected and subject to Protective Order No. 17-057. The other values are updated in the PGE forecast by using 2016 actual data through September 2016 and then inflating the remaining months using an inflation rate of 2.54%.

n. The purpose of the line item titled “Stock Incentive Plan RMGMT” detailed on Row 56 is to record the deferred tax liability associated with the timing of when the costs of stock incentive plans are recorded for book versus tax. The supporting work paper for this amount is included as Attachment 064-R, line 963, which is protected and subject to Protective Order No. 17-057. As we do not track this item in our forecasts we assumed no change to the balance.

o. Deferred broker settlements consist of transactions that have been financially settled by clearing brokers prior to the contract delivery date. These gains and losses are deferred for future recovery in customer prices during the corresponding contract settlement month. The timing of deductibility is different for tax purposes. The line item titled “Deferred Broker Settlements” detailed on row 54 contains the deferred tax effect of this temporary difference. The supporting work paper for this amount is included as Attachment 064-S, which is protected and subject to Protective Order No. 17-057. The 2016 value is actual results through September (see Attachment 064-F) plus a forecasted amount that was entered from the wrong source. The corrected amount is on line 22 of the attached worksheet that is designated as Attachment 064-G. The corrected values for this row are:

2015 ADIT	2016 ADIT	2017 ADIT	2016 M Act	2017 M Act	2018 M Act
($711,248)	($1,462,032)	($1,422,496)	($1,876,959)	$98,839	$0

p. O&M costs for the development of PGE's new customer system (CET) are deferred and amortized pursuant to OPUC Final Order No. 13-459 (Docket UE 262 – PGE's General Rate Case). For tax purposes those costs are deducted when incurred. The line item titled "CET 2014 Deferral," detailed on row 44, records the deferred tax associated with this book/tax temporary difference. The supporting work paper for this amount is included as Attachment 064-T, which is protected and subject to Protective Order No. 17-057. The 2016 value is actual results through September (see Attachment 064-H) plus a forecasted amount detailed in the Attachment 064-I, line 6. The 2017 and 2018 forecasted M activity is also supported by Attachment 064-I, lines 37 and 44, respectively.

June 6, 2017

TO:

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU Data Request No. 092
Dated April 13, 2017

<u>Request:</u>
Reference the Company's response to ICNU data request 64(c), Confidential Attachment 064A:

- **a. Please explain why, for ratemaking purposes, the value detailed in Cell "I18" of tab "R216-Rate Base-2017" is appropriately considered to be a permanent book/tax difference, rather than a temporary book/tax difference.**
- **b. Please describe how the Company's tax software calculates the hard-coded values on Row "18" of tab "R216-Rate Base-2017."**
- **c. Please provide any workpapers used as input to the Company's tax software for purposes of calculating the hard-coded values on Row "18" of tab "R216-Rate Base-2017."**
- **d. Please provide all accounting details, workpapers, or any other information the Company believes to be relevant for supporting the hardcoded value in Cell "I18" of Tab "R216-Rate-Base-2017."**
- **e. Please explain why, for ratemaking purposes, the amount detailed in Cell "I34" of tab "R216-Rate Base-2017" is appropriately considered to be a permanent book/tax difference, rather than a temporary book/tax difference.**
- **f. Please describe how the Company's tax software calculates the hard-coded values on Row "34" of tab "R216-Rate Base-2017."**
- **g. Please provide any workpapers used as an input to the Company's tax software for purposes of calculating the hard-coded values on Row "34" of tab "R216-Rate Base-2017."**
- **h. Please provide all accounting details, workpapers, or any other information the Company believes to be relevant for supporting the hardcoded numbers in cell "I34" of tab "R216-Rate Base-2017."**

<u>Response:</u>

Within the referenced worksheet there are no true permanent book/tax differences. There are temporary book/tax differences that are treated as flow-through book/tax differences. Flow-through book/tax differences are similar to permanent book/tax differences in that there is no deferred tax expense recorded. The difference is that flow-through book/tax differences do reverse over time. However, both at the time the difference originates and as the difference reverses there is no deferred tax expense recorded. The offsetting entry to the accumulated deferred tax liability or asset is a regulatory asset or liability. There is, therefore, no rate base effect for flow-through items as the deferred tax liability/asset is offset by its corresponding regulatory asset/liability.

See PGE's response to ICNU Data Request No. 64, Attachment 64-A. All cell references in our responses correspond to Attachment 64-A.

a. Cell "I18" of tab "R216-Rate Base-2017" is the total of the two cells above it. These cells contain the reversal of flow-through book/tax differences. They are treated as flow-through temporary book/tax differences because they received flow-through treatment when the differences originated in prior years.

b. Row "18" is the total of the two rows above it. The explanation of the tax system process for each column of the rows above Row "18" is as follows:

Column B:	The system allocates a portion of tax depreciation to the tax basis book/tax differences.
Column C:	The system allocates a portion of the tax gain/loss to the tax basis book/tax differences.
Column D:	The sum of Columns B and C.
Columns E & F:	The system allocates the allocated book depreciation (Column G) between book depreciation and book gain/loss.
Column G:	The system allocates a portion of book depreciation to the book basis book/tax differences.
Column H:	Contains the originating book tax differences.
Column I:	Is the difference between Columns B and E.
Column J:	Is the difference between Columns C and F.
Column K:	Is the originating basis difference (with the sign opposite from the sign in column H).
Column L:	Is the deferred tax effect of Column I (always zero for a flow-through item).
Column M:	Is the deferred tax effect of Column J (always zero for a flow-through item).
Column N:	Is the deferred tax effect of Column K (always zero for a flow-through item).
Column O:	Is the total of columns L to N.

c. There are no work papers for the lines referenced because the rows that total to Row "18" are only reversals of prior book/tax differences; there are no entries made to the tax system for purposes of calculating these lines. All the calculations are made within the system.

d. See PGE's response to parts (a) and (c) above.

e. Cell "I34" of tab "R216-Rate Base-2017" is the total of the five cells above it. These cells contain the reversal of flow-through book/tax differences. They are treated as flow-through temporary book/tax differences because they received flow-through treatment when the differences originated in prior years.

f. Row "34" is the total of the five rows above it. The explanation of the tax system process for each column of the rows above Row "34" is the same as the explanation given in question b above.

g. Row "34" is the total of the five rows above it. The majority of the entries in the five rows above Row "34" are reversals of prior book/tax differences and no entries are made to the tax system for purposes of calculating reversals. The only exception is the entry in Cell "K30", which is an originating flow-through difference (AFDC Equity). The amount in Cell "K30" is the AFDC Equity that relates to the assets placed in service in 2016 and is a feed from the Company's Asset system to PowerTax. Attachment 092-A shows $43,009,550 of AFDC Equity placed in service in 2016 shows. The estimate at the time the system was run for the rate case was $42,617,395.

h. Please see response to parts (e) and (g) above and Attachment 092-A (cell I34).

June 6, 2017

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

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 093
Dated May 23, 2017

Request:

Reference the Company's response to ICNU Data request 64(h), regarding taxation of Orion contingent royalty payments:

a. **Please provide contractual documentation supporting the contingent royalty payment obligations to Orion.**

b. **Please describe how the Company accounts for the described contingent royalty payments in the MONET model and in revenue requirement, generally.**

c. **Please provide a description of the circumstances under which the Company must make contingent payments to Orion.**

d. **Please provide detail of the amount of each contingent royalty payment that has been made since 2006.**

Response:

a. Attachment 093-A provides the contracts supporting PGE's contingent royalty payment obligations to Orion. Attachment 093-A is protected and subject to Protective Order 17-057.

b. PGE accounts for the described contingent royalty payments in the MONET model through the following equation:

(Orion Royalty Price, \$/MWh) = (Orion Royalty Factor, %) x (Orion Royalty Power Price, \$/MWh)

The Orion Royalty Price is a calculation of the price of royalty payments in dollars per MWh. It represents a contract defined market power price. The Royalty Prices are included in the calculation of the total monthly royalty cost as described in the Biglow Royalty MFR.

The described contingent royalty payment costs are accounted for in the net variable power cost portion of revenue requirement. Contingent royalty payments to Orion are tax deferred and are excluded from the rate base.

c. In 2006, PGE purchased windfarm assets and development rights from Orion Energy. As part of that purchase price, PGE agreed to pay contingent royalty payments to Orion. PGE must make contingent royalty payments to Orion when power (measured in MWh) is generated.

d. Attachment 093-B details the amount of each contingent royalty payment made since 2006. Payments are made semi-annually. The first royalty payment was made in the 4th quarter of 2007. The first few payments from 2007 to 2008 were not recorded in Excel; they are PDFs. From 2009 onward, the royalty payments are recorded in an Excel file. Attachment 093-B is protected and subject to Protective Order 17-057.

June 6, 2017

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

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 094
Dated May 23, 2017

Request:

Reference the Company's response to ICNU data request 64(i): Please provide a copy of the Company's Form 4626 for tax year 2008.

Response:

PGE's tax forms are highly confidential. PGE would like to request that ICNU make arrangements to review Tax Form 4626 at PGE offices at a mutually agreeable time.

June 6, 2017

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

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 095
Dated May 23, 2017

Request:

Reference the Company's response to ICNU 64(j), specifically Confidential Attachment 064-N:

a. **Please state when the Company expects to perform the referenced test-firing at Boardman with biomass.**

b. **Please describe the status of the Boardman biomass conversion project.**

c. **Please provide any internal memoranda submitted to management within the past year concerning the status of the Boardman biomass-conversion project.**

d. **Please identify the Commission order where the Company was allowed to defer the referenced revenues or, if none exists, the Company's application requesting authorization to defer the referenced revenues.**

e. **Is the deferred revenue associated with the test-firing activities included as a reduction to rate base in the revenue requirement the Company proposes in this matter?**

f. **Does the Company include any test period costs associated with the Boardman biomass conversion project in revenue requirement in this matter? If yes, please identify all such costs, by FERC account.**

g. Has the Company been capitalizing any costs associated with the biomass conversion project. If yes, please identify all rate base and Construction Work In Progress amounts included in revenue requirement in this matter related to the biomass conversion project.

Response:

a. The co-fire test occurred on 11/24/2015. The 100% test fire occurred in four stages – a single-mill test occurred on 12/06/2016 and was re-tested on 12/12/2016; another pulverizer test occurred on 02/17/2017 and the final test fire utilizing 100% biomass and four pulverizers occurred on 02/23/2017. Extended pulverizer run time tests are anticipated in the second of half of 2017.

b. The series of test burns noted above yielded valuable information that was used in subsequent test burns. The data are also being utilized in air permit modeling and to determine equipment requirements for emission controls as PGE continues to evaluate the potential conversion to a biomass operation. As noted above, extended pulverizer run time tests are anticipated in the second of half of 2017.

c. Attachment 095-A is an internal status update on the Biomass Project. This document is inclusive of all prior updates.

d. The initial revenue for the test burn(s) was approved in Commission Order No. 13-280 (UE 266), Net Variable Power Costs (NVPC) and Annual Power Cost Update Stipulation filed August 5, 2013 [Item C, Biomass Test Burn, page 5].

- Co-fire Test: The $3 million for the co-fire test was collected from customers and deferred in 2014. The co-fire test burn did not occur in 2014 and the revenue (with interest) was refunded as part of the 2015 NVPC, Order 14-422, dated 12/04/2014. The co-fire test revenue was refunded and re-collected in 2015 and the co-fire test occurred on 11/24/2015.

- 100% Test: The $3 million for the 100% biomass test was collected from customers and deferred in 2015. The 100% test burn did not occur in 2015 and the revenue (with interest) was refunded as part of the 2016 NVPC, Order 15-356, dated 11/03/2015. The 100% test revenue was refunded and re-collected in 2016 and the 100% biomass testing occurred on 12/06/2016, 12/12/2016, 02/17/2017 and 02/23/2017, as noted in part (a) above. Extended pulverizer run time tests are anticipated in the second of half of 2017. An application for Deferred Accounting was submitted since the 100% test burn was not completed in 2016 and the Deferred Accounting Order 17-023, dated 01/24/2017, was approved.

e. No. The deferred revenue associated with the test-firing activities is included in rate base.

f. Yes. PGE included two items in the test year revenue requirement as follows:

- PGE inadvertently included $1.1 million for an accumulated deferred income tax (ADIT) asset associated with the deferred revenue discussed in part e, above. Because the liability associated with the deferred revenue was not included in rate base, the ADIT asset should not have been included either.
- PGE capitalized $394,000 (FERC account 368) as part of the biomass project for the purchase and installation of a 2500 kVA transformer and switchgear for station service needed to power the biomass equipment. This equipment is also available for use elsewhere in PGE's distribution system.

g. See PGE's response to part (f) above.

June 5, 2017

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

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 098
Dated May 23, 2017

Request:

Does the Company's lead-lag study account for Accrued A/P Vacation costs as a source of financing?

That is, does the lead-lag study account for the lag between when vacation costs are incurred and when the amounts are ultimately paid to employees?

If yes, please identify where in the lead-lag study these amounts are captured.

If no, please explain why the Company does not view these Accrued A/P Vacation costs amounts as a source of financing for ratemaking purposes.

Response:

For the purpose of this response, PGE assumes the request is in reference to accrued vacation costs. Payment of these benefits is a payroll function rather than an A/P function.

No. The accrual of vacation costs is neither a source nor use of cash and therefore does not impact working cash. With the exception of terminations, employee pay is a function of hours (worked, vacation, etc.) and is captured in the wages and salaries portion of the lead-lag study. For terminations only, the balance of accrued vacation time (if any) is paid out on the employee's last day.

June 8, 2017

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

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 319
PGE Response to ICNU DR No. 099
Dated May 25, 2017

<u>Request:</u>

Reference PGE/200 workpaper "Exhibit Support 2018.xlsx," Sheet "depr":

a. **Please provide electronic workpapers supporting the $328.4 of depreciation expense forecast for the 2018 rate year.**

b. **Please provide a reconciliation between the $328.4 million of depreciation expense included in the referenced workpaper and the approximate $286.1 million depreciation accrual calculated in PGE's depreciation study at Attachment A Part I, Page 68.**

c. **Please provide transaction-level detail, and any other available supporting workpapers, underlying the $7.3 million of asset retirements forecast in the 2018 rate year.**

d. **Does the Company agree that depreciation expense is calculated in a manner that provides the Company with cost recovery for interim asset retirements? Please explain.**

e. **Please describe how the unrecovered book value of a retired asset is treated in the Company's depreciation study.**

f. **Please provide a description of the $12.3 million amount in the column titled "Adjust for Declining Balance."**

g. **Please provide workpapers used to calculate the $12.3 million value in the column titled "Adjust for Declining Balance."**

h. Please provide a description of the $5.9 million value in the column titled "Remove Bdmn Decomm Including Severance and Incentives."

i. Please provide a workpapers used to calculate the $5.9 million value in the column titled "Remove Bdmn Decomm Including Severance and Incentives."

Response:

a. Please see PGE Exhibit 203 for the details supporting the $317.4 depreciation expense forecast for the 2018 test year. The $328.4 million referenced in this data request is the amount before adjusting for declining balance, removing Boardman Decommissioning costs, making a retail revenue adjustment, and including the Asset retirement depreciation.

b. PGE's Depreciation Study is based on depreciable balances as of December 31, 2015 in the amount of $286.1 million. PGE's 2018 test year rate case filing is based on estimated year-end 2017 plant balances resulting in depreciation expense forecast in the amount of $317.4 million for the 2018 test year. The most significant change, as identified in PGE Exhibit 203, is the Carty generation plant, which was placed in service in July 2016 and was not included in the 2015 year-end plant balances.

c. Attachment 099-A provides the breakdown of depreciation expense related to the asset retirement obligation. PowerPlan is the system of record for calculation depreciation. Thus, there is no transaction-level detail available.

d. Depreciation expense is calculated in a manner that provides PGE with cost recovery for interim retirements based on the survivor curve. This concept is part of group depreciation and the remaining life technique.

e. All regulated utilities utilize group depreciation which establishes full recovery of all assets over the full life cycle of the account. Therefore, based on the survivor curve, some assets are retired and recovered before the expected life cycle and others are retired and recovered after the expected life cycle. With the remaining life method, the unrecovered book value of retired assets is recovered over the life of the remaining assets in the account.

f. Please see PGE Exhibit 200, Section III, page 6, lines 1 to 19 for the explanation of the Declining Balance adjustment.

g. Attachment 099-B provides the estimated depreciation expense using the annualized process used to calculate the adjustment related to Declining Balance.

h. The $5.9 million represents an estimate of the 2018 Boardman decommissioning costs that are being collected through Schedule 145 (i.e., avoids double collection). These costs are based on decommissioning beginning December 31, 2020 and the site being returned to substantially the same conditions as before the plant was constructed. The estimate also includes all currently known disposal and environmental cleanup costs. The overall decommissioning costs are partly offset by the scrap value of all useful metals and materials.

i. Attachment 099-C, tab “Tariff,” Cell O56, provides the calculation of the $5.9 million referenced in PGE Exhibit 200 Work Papers, “Exhibit Support” for Boardman decommissioning costs. This amount was approved by the Commission in PGE’s Advice No. 15-24 on October 27, 2015. Boardman decommissioning cost estimates were revised in PGE’s Advice No. 16-16 resulting in a revised amount of $4.2 million. However, this revision does not affect the 2018 test year revenue requirement because the initial calculation of the 2018 revenue requirement included the $5.9 million that is adjusted out.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 319

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

EXHIBIT NO. ICNU/304

INTERNAL REVENUE SERVICE PRIVATE LETTER RULING 201418024

Internal Revenue Service

Number: **201418024**
Release Date: 5/2/2014

Index Number: 167.22-01

Department of the Treasury
Washington, DC 20224

Third Party Communication: None
Date of Communication: Not Applicable

Person To Contact:
, ID No.

Telephone Number:

Refer Reply To:
CC:PSI:B06
PLR-133813-13

Date:
January 27, 2014

LEGEND:

Taxpayer	=
Parent	=
State	=
Commission	=
Year A	=
Year B	=
Year C	=
Year D	=
Year E	=
X	=
Y	=
Date A	=
Date B	=
Date C	=
Date D	=
Date E	=
Case	=
Director	=

Dear . :

This letter responds to the request, dated July 30, 2013, of Taxpayer for a ruling on whether the Commission's treatment of Taxpayer's Accumulated Deferred Income

Tax (ADIT) account balance in the context of a rate case is consistent with the requirements of the normalization provisions of the Internal Revenue Code.

The representations set out in your letter follow.

Taxpayer is a regulated public utility incorporated in State. It is wholly owned by Parent. Taxpayer distributes and sells natural gas to customers in State. Taxpayer is subject to the regulatory jurisdiction of Commission with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer takes accelerated depreciation where available and, for the period beginning in Year A and ending in Year E, Taxpayer has, in the aggregate, produced more net operating losses (NOL) than taxable income. After application of the carryback and carryforward rules, Taxpayer represents that it has net operating loss carryforward (NOLC), produced in Year C and Year E, of $X as of the end of Year E. The amount of claimed accelerated depreciation in Year C and Year E exceeded the amount of the NOLCs for those years. In Year D, Taxpayer produced regular taxable income as well as alternative minimum taxable income (AMTI); the regular taxable income was offset by the NOLCs from Year B and year C but could not offset the entire alternative minimum tax (AMT) liability due to the limitation in § 56(d). Taxpayer paid $Y of AMT in Year D and had a minimum tax credit carryforward (MTCC) as of the end of year E of $Y.

On its regulatory books of account, Taxpayer “normalizes” the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute “cost-free capital” to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account and also maintains an offsetting series of entries that reflect that portion of those ‘tax losses’ which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC. With respect to the $Y AMT liability from Year D, Taxpayer carried that amount as an offset to the ADIT because the AMT increased the payment of tax.

Taxpayer filed a general rate case on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In establishing the income tax expense element of its cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission policy and were not flowed thru to ratepayers. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission generally offsets rate base by Taxpayer’s plant based ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of

NOLCs or the AMT. Commission, in an order issued on Date C, did not use the amounts that Taxpayer calculates did not defer tax due to NOLCs or AMT but only the amount in the ADIT account. Taxpayer filed a petition for reconsideration based on the normalization implications of the order. On Date D, Commission rejected Taxpayer's request. Taxpayer again requested reconsideration and the Commission denied that request on Date E. Commission asserts that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has, such as in this case, an NOLC or AMT. Thus, Commission asserts that it has already recognized the effects of the NOCL in setting rates and there is no need to reduce the ADIT by the other amounts due to NOLCs or AMT.

Taxpayer requests that we rule as follows:

Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

<u>Law and Analysis</u>

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a “normalization method of accounting.” A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer’s use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer’s reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 55 of the Code imposes an alternative minimum tax on certain taxpayers, including corporations. Adjustments in computing alternative minimum taxable income are provided in § 56. Section 56(a)(1) provides for the treatment of depreciation in computing alternative minimum taxable income. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

In the rate case at issue, Commission has excluded from the base to which the Taxpayer's rate of return is applied the reserve for deferred taxes, unmodified by the accounts which Taxpayer has designed to calculate the effects of the NOLCs and MTCC. There is little guidance on exactly how an NOLC or MTCC must be taken into account in calculating the reserve for deferred taxes under §§ 1.167(1)-1(h)(1)(iii) and 56(a)(1)(D). However, it is clear that both must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT) for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Both Commission and Taxpayer have intended, at all relevant times, to comply with the normalization requirements. Commission has stated that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates. Because the NOLC and MTCC have been taken into account, Commission's decision to not reduce the amount of the reserve for deferred taxes by these amounts does not result in the amount of that reserve for the period being used in determining the taxpayer's expense in computing cost of service exceeding the proper amount of the reserve and violate the normalization requirements. We therefore conclude that the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above. In particular, while we accept as true for purposes of this ruling Commission's assertions that it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or AMT, we do not conclude that it has done so and those assertions are subject to verification on audit.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman
Senior Technician Reviewer, Branch 6
(Passthroughs & Special Industries)

cc: