Oregon

John A. Kitzhaber. MD. Governor

Public Utility Commission
3930 Fairview Industrial Dr SE
Salem OR 97302
Mailing Address: PO Box 1088
Salem, OR 97308-10885
Consumer Services
1-800-522-2404
Local: (503) 378-6600
Administrative Services
(503) 373-7394

June 11, 2014

Via Electronic Filing and U.S. Mail

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

RE: Docket No. UE 283 –In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision.

Enclosed for electronic filing is Staff Redacted Opening Testimony in UE 283. A hard copy and a CD of the Redacted Testimony are being placed in today's mail.

The following confidential testimony pages and exhibits are also mailed to parties who have signed Protective Order 14-043.

Exhibit 300, pages 4, 21, 22, 28 & 45
Exhibit 302, pages 31 – 39
Exhibit 303, pages 1 – 2
Exhibit 304, pages 1 – 9
Exhibit 307, page 2 and
Exhibit 308, page 1

Exhibit 402, pages 4, 9, 10 & 27

Exhibit 500, page 2
Exhibit 502, page 1

Exhibit 800, pages 5 – 7
Exhibit 803, pages 1 – 3
Exhibit 804, page 1

Exhibit 1100, pages 13 – 18, 22, 25 & 26
Exhibit 1104, page 1

For parties who have signed the Protective Order, included in the mailing is a CD containing confidential work papers.

A CD containing non-confidential work papers is included for parties who have not signed the Protective Order.

/s/ Kay Barnes

Kay Barnes
PUC - Utility Program
(503) 378-5763
kay.barnes@state.or.us

c: UE 283 - Service List (parties)

CERTIFICATE OF SERVICE

UE 283

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 11th day of June, 2014 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
3930 Fairview Industrial Drive SE
Salem, Oregon 97302
Telephone: (503) 378-5763

UE 283 SERVICE LIST

BOEHM KURTZ & LOWRY	
KURT J BOEHM **(C)** ATTORNEY	36 E SEVENTH ST - STE 1510 CINCINNATI OH 45202 kboehm@bkllawfirm.com
BOEHM, KURTZ & LOWRY	
JODY KYLER COHN ATTORNEY	36 E SEVENTH ST STE 1510 CINCINNATI OH 45202 jkyler@bkllawfirm.com
CITIZENS' UTILITY BOARD OF OREGON	
OPUC DOCKETS	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
ROBERT JENKS **(C)**	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org
G. CATRIONA MCCRACKEN **(C)**	610 SW BROADWAY, STE 400 PORTLAND OR 97205 catriona@oregoncub.org
CITY OF PORTLAND - CITY ATTORNEY'S OFFICE	
BENJAMIN WALTERS	1221 SW 4TH AVE - RM 430 PORTLAND OR 97204 ben.walters@portlandoregon.gov
CITY OF PORTLAND - PLANNING & SUSTAINABILITY	
DAVID TOOZE	1900 SW 4TH STE 7100 PORTLAND OR 97201 david.tooze@portlandoregon.gov
DAVISON VAN CLEVE PC	
S BRADLEY VAN CLEVE **(C)**	333 SW TAYLOR - STE 400 PORTLAND OR 97204 bvc@dvclaw.com
DAVISON VAN CLEVE, PC	
TYLER C PEPPLE **(C)**	333 SW TAYLOR SUITE 400 PORTLAND OR 97204 tcp@dvclaw.com
ENERGY STRATEGIES LLC	
KEVIN HIGGINS **(C)**	215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com
FRED MEYER STORES/KROGER	
NONA SOLTERO	3800 SE 22ND AVE PORTLAND OR 97202 nona.soltero@fredmeyer.com
MOUNTAIN WEST ANALYTICS	
BRADLEY MULLINS **(C)**	333 SW TAYLOR STE 400 PORTLAND OR 97204 brmullins@mwanalytics.com

NOBLE AMERICAS ENERGY SOLUTIONS, LLC	
GREG BASS	401 WEST A ST., STE. 500 SAN DIEGO CA 92101 gbass@noblesolutions.com
NORTHWEST NATURAL	
E-FILING	220 NW 2ND AVE PORTLAND OR 97209 efiling@nwnatural.com
MARK R THOMPSON	220 NW 2ND AVE PORTLAND OR 97209 mark.thompson@nwnatural.com
NW ENERGY COALITION	
WENDY GERLITZ **(C)**	1205 SE FLAVEL PORTLAND OR 97202 wendy@nwenergy.org
PACIFIC POWER	
SARAH WALLACE	825 NE MULTNOMAH ST STE 1800 PORTLAND OR 97232 sarah.wallace@pacificorp.com
PACIFICORP, DBA PACIFIC POWER	
OREGON DOCKETS	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
PORTLAND GENERAL ELECTRIC	
DOUGLAS C TINGEY **(C)**	121 SW SALMON 1WTC1301 PORTLAND OR 97204 doug.tingey@pgn.com
JAY TINKER **(C)**	121 SW SALMON ST 1WTC-0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
PUBLIC UTILITY COMMISSION OF OREGON	
JUDY JOHNSON **(C)**	PO BOX 1088 SALEM OR 97308-1088 judy.johnson@state.or.us
PUC STAFF--DEPARTMENT OF JUSTICE	
STEPHANIE S ANDRUS **(C)**	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@state.or.us
RICHARDSON ADAMS, PLLC	
GREGORY M. ADAMS	PO BOX 7218 BOISE ID 83702 greg@richardsonadams.com

PUBLIC UTILITY COMMISSION OF OREGON

UE 283

STAFF OPENING TESTIMONY OF

Marianne Gardner
Matthew (Matt) Muldoon
Lance Kaufman
Brian Bahr
Linnea Wittekind
Deborah Garcia
George R. Compton
Suparna Bhattacharya
Jorge Ordonez
Judy Johnson
Ryan Bracken
John Crider

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

REDACTED

June 11, 2014

CASE: UE 283
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

June 11, 2014

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

A. My name is Marianne Gardner. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

Q. Please, describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I am the revenue requirements summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding. As such, I introduce and summarize the Staff-sponsored adjustments to Portland General Electric's ("PGE" or "Company") filing in this docket, identified as UE 283. Second, I provide some detail regarding the partial settlement reached in principal with Portland General Electric, as well as Citizens' Utility Board of Oregon (CUB), Industrial Customers of Northwest Utilities (ICNU), Fred Meyer Stores and Quality Food Centers, divisions of The Kroger Co. (Kroger), and City of Portland. Last, I present the contested adjustments and issues as identified by Staff.

Q. Please provide a list of Staff and the issues that each addresses.

A. The following Staff are responsible for the following issues.

Witness	**Issue(s)**
Bahr	Medical Benefits, Pensions
Bhattacharya	Energy Marginal Cost Study, Transmission Marginal Cost Study
Boyle	Fee Free Bankcard
Bracken	RPS Carve Out
Compton	Large Customer Rate Design

Crider	Net Variable Power Costs, Purchase Power Agreement with Confederated Tribes of Warm Springs, Boardman Plant Purchase
Garcia	Plant in Service
Gardner	Revenue Requirement, Revenue Sensitive rates, Uncollectible expense, Customer Accounts, Interest Synchronization, Miscellaneous Labor, Property Tax, Depreciation and Accumulated Depreciation, M&S Inventory and Working Capital
Johnson Judy	Software Amortization, Environmental Remediation
Johnson Juliet	Advertising, Customer Assistance
Kaufman	Other Revenue, Postage, Sales Forecast, Customer Marginal Cost Study, Line Extension, Reactive Power
Muldoon	Rate of Return and Capital Structure
Ordonez	Grant Tariffs – Port Westward 2 and Tucannon Wind Farm
Rossow	Sponsorships, Memberships
Wittekind	Various A&G and D&O

Q. Is there a difference between the revenue requirement requested by PGE and the amount Staff proposed?

A. Yes. To summarize, PGE requested an increase to revenue requirement related to base rates of approximately $12.5 million. This $12.5 million revenue requirement amount does not include PGE's requested revenue requirement for Port Westward 2 and Tucannon Wind Farm projects. Staff proposed twenty-four adjustments to PGE's requested revenue requirement and identified several other issues with PGE's filing. A partial settlement has been reached on some of Staff's adjustments. However, a proposed revenue requirement amount is unavailable at this time.

Q. How is your testimony organized?

A. My testimony is divided into two parts:

Part I explains the partial settlement.

Part II introduces the contested adjustments and issues.

PART I – EXPLANATION OF PARTIAL SETTLEMENT

Q. Please, provide a list of Staff's adjustments.

A. The table below provides an item number for each Staff adjustment and issue, the initials of the responsible Staff witness, and a notation indicating whether the issue has been resolved through settlement.

Item	Staff	Description	Status
S-0	MM	**Rate of Return**	**(Partial Settlement)**
S-1	MG	**Revenue Sensitive rates & Uncollectible Expense**	**(Settled)**
S-2	MG	**Customer Accounts**	**(Contested)**
S-3	MG	**Interest Synchronization**	**(Settled)**
S-4	LK	**Other Revenue**	**(Settled)**
S-5	Juliet J.	**Advertising**	**(Settled)**
S-6	Juliet J.	**Customer Assistance**	**(Settled)**
S-7	LK	**Postage**	**(Contested)**
S-8	PR	**Sponsorships**	**(Settled)**
S-9	PR	**Memberships**	**(Settled)**
S-10	JC	**Rate Base- EIM & related Amortization Expense**	**(Settled)**
S-11	BB	**Medical Benefits**	**(Contested)**
S-12	BB	**Rate Base - Pension**	**(Contested)**
S-13	MG	**Miscellaneous Labor**	**(Contested)**
S-14	LW	**Various A&G and D&O**	**(Partial Settlement)**
S-15	PB	**Fee Free Bankcard**	**(Settled)**
S-16	LK	**Sales Forecast**	**(Contested)**
S-17	DG	**Rate Base – Plant in Service**	**(Contested)**
S-18	Judy J.	**Software Amortization**	**(Settled)**
S-19	MG	**Property tax expense**	**(Settled)**
S-20	MG	**Depreciation & Accumulated Depreciation**	**(Settled)**

S-21	JC	**Net Variable Power Costs**	**(Contested)**
S-22	MG	**M&S Inventory and Working Capital**	**(Settled)**
S-23	JC	**Purchase Power Agreement with Confederated Tribes of Warm Springs**	**(Settled)**
S-24	JC	**Boardman Plant Purchase**	**(Contested)**
I-1	GC	**Large Customer Rate Design**	**(Contested)**
I-2	LK	**Customer Marginal Cost Study**	**(Contested)**
I-3	LK	**Line Extension**	**(Contested**
I-4	SB	**Energy Marginal Cost Study**	**(Contested)**
I-5	SB	**Transmission Marginal Cost Study**	**(Contested)**
I-6	LK	**Reactive Power**	**(Contested)**
I-7	JO	**Grant Tariffs- Port Westward 2 and Tucannon Wind Farm**	**(Contested)**
I-8	Judy J.	**Environmental Remediation**	**(Contested)**
I-9	RB	**RPS Carve Out**	**(Contested)**

Q. Which parties have agreed to the partial settlement?

A. PGE, CUB, ICNU, Kroger, the City of Portland, as well as Staff have agreed to the settlement in principal.

Q. Has a formal settlement agreement been filed with the OPUC?

A. No. However, the parties are currently drafting an agreement and will be drafting supporting testimony as well.

PART II – INTRODUCTION OF CONTESTED ADJUSTMENTS AND ISSUES

Q. Please provide a listing of the responsible Staff witnesses for contested adjustments and issues and the associated Exhibits.

A. The following Staff will provide testimony on the listed contested issues.

Witness	Exhibit	Subject(s)
Gardner	100	Customer Accounts, Miscellaneous Labor
Muldoon	200	Rate of Return and Capital Structure
Kaufman	300	Postage, Sales Forecast, Customer Marginal Cost Study, Line Extension, Reactive Power
Bahr	400	Medical Benefits, Pensions
Wittekind	500	D&O
Garcia	600	Plant in Service
Compton	700	Large Customer Rate Design, Rate Spread and Rate Design
Bhattacharya	800	Energy Marginal Cost Study, Transmission Marginal Cost Study
Ordonez	900	Grant Tariffs- Port Westward 2 and Tucannon Wind Farm
Johnson Judy	1000	Environmental Remediation
Bracken	1100	RPS Carve Out
Crider	1200	PGE Boardman Purchase from PRC

Q. Has Staff provided estimated adjustments to the 2015 test year revenues, expenses or rate base dollars for any of these contested issues?

A. Yes. Staff has provided the following estimates. The proposed adjusted amounts for the rest of the contested items are still pending. Staff will explain more fully in each of their respective testimonies.

Item	Staff	Description	Status	Proposed Adjustment ($000)		
				Revenue	Expense	Rate Base
S-7	LK	Postage	(Contested)		($518)	
S-11	BB	Medical Benefits *	(Contested)		($783)	
S-12	BB	Pension	(Contested)			($49,060)
S-14	LW	D&O	(Contested)		($552)	
I-8	Judy J.	Environmental Remediation	(Contested)		($3,100)	

* Adjustment for change in premium sharing from 85/15 to 82/18.

Q. Briefly describe the contested adjustments for Items S-2 and S-13 for which you are responsible.

A. For Item S-2, Staff proposes an adjustment to Customer Account 903 for Customer Engagement Transformation expenses. In the review of Customer Accounts, 901-905, Staff examined PGE's responses to Standard Data Request (SDR) Nos. 57 and 58. In addition, Staff issued four follow-up data requests. In Staff's analysis, Staff found a substantial increase in expense related to PGE's Customer Engagement Transformation department. However, it appears that PGE has deferred $4.8 million of this 2015 expense. Currently, Staff is still in discovery. Therefore, at this time, Staff is uncertain if an adjustment is necessary pending PGE's response to Staff's outstanding DR No. 504.

For Item S-13, Staff has proposes an adjustment to PGE's 2015 test year Wages and Salaries and related accounts based on Staff's Wage and Salary model. Staff reviewed PGE's responses to SDR Nos. 95-106. These SDRs were developed to provide Staff with the information needed to calculate an appropriate level of wages, salaries, and overtime for a utility's test year. Staff sent an additional 33 data requests to gain insight into PGE's increase in wage and salary expense for the 2015 test year. Staff reviewed the trend of actual expenses and full-time equivalent employees (FTE) from 2011 through 2013 as compared to the 2015 test year, as well as PGE's budgeted wage and salary data against actual results for those same years.

Using Staff's 3-year Wage and Salary Model (Staff Model), Staff calculated an adjustment to Miscellaneous Labor. For approximately 29 years, the Commission has used or upheld the Staff's Model. The Staff Model was explicitly adopted in Order No. 95-322 at 10, where the Commission stated: "... this Commission has relied on staff's model for over ten years to monitor energy utilities' wages and salaries for both general rate cases and earnings tests associated with deferred accounting. The current model produces a reasonable and reliable result."

The primary areas that PGE and Staff diverge are as follows:

- Escalation; PGE's escalation percentages differed from those developed by the Oregon Department of Administrative Services, Office of Economic Analysis, which is the source for the All-Urban (US) CPI that Staff has historically used to escalate non-union wage and salary data. In addition, based on Staff's historical method, Staff calculates union wage and salary increases based on actual contractual increases. In this case, Staff has proposed an average of 2012, 2013 and 2014 contracted increases. According to their testimony, UE 283/PGE/600, Barnett – Jaramillo at 9, PGE's escalation is "Based on market surveys and Bureau of Labor Statistics Data ..."
- Full-time equivalents; Staff presently proposes a reduction to PGE's 2015 test year FTE level. Staff's adjustment is pending, as PGE has not yet responded to several of Staff data requests.

- Incentives; In accordance with Commission policy, Staff proposes to disallow 100 percent of officers' bonuses, because they are based on increased earnings. (Order 99-033 at 62; Order 97-171 at 74-76.) Therefore, Staff has proposed removal of all officers' bonuses included in PGE 2015 test year. In addition, Staff proposes to disallow an additional portion of the 50 percent of non-officer bonuses included in the 2015 test year. However, Staff's adjustment is pending PGE's response to Staff's outstanding data requests.

Q. Does this conclude your direct testimony?

A. Yes.

CASE: UE 283
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME:	Marianne Gardner
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Revenue Requirement Analyst
ADDRESS:	3930 Fairview Industrial Dr SE, Oregon 97308-1088
EDUCATION:	Master of Business Administration Oregon State University, Corvallis, Oregon Bachelor of Science in Accounting Montana State University, Bozeman, Montana CPA, Oregon
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since March 2013 in the Energy - Rates, Finance and Audit Division of the Utility Program. My responsibilities include research, analysis and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. In my role as summary witness, I have provided testimony in dockets UE 263 and UG 246.

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

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

CASE: UE 283
WITNESS: Matt Muldoon

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

June 11, 2014

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

A. My name is Matt Muldoon. My business address is:
3930 Fairview Industrial Dr. SE, Salem, OR 97302-1166.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement can be found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. I am responsible for three issues regarding Cost of Capital (CoC) in this docket:

1. Capital Structure,
2. Cost of Long Term (LT) Debt, and
3. Return on Common Equity (ROE).

Q. Are any of those issues included in the partial settlement reached among parties to this rate case?

A. Yes. The first two issues were resolved. Staff anticipates that the stipulation and supporting testimony will be filed in June 2014. The third issue, ROE, remains contested.

Q. What is your summary recommendation?

A. I recommend PGE's ROE be set to 9.2 percent.

Q. PGE is requesting an ROE of 10.0 percent and the Company's ROE witness Dr. Zepp provides a multistage discounted cash flow model estimating a 9.9 percent ROE. What is the main basis for the difference from your recommended 9.2 percent ROE?

A. There are several reasons, but primarily because Dr. Zepp uses an inordinately high LT growth rate for the third stage of his discounted cash flow (DCF) model. To a lesser extent, results also differ because the cohort of companies Dr. Zepp uses to perform his DCF model is a less targeted proxy for PGE than Staff's peer utility proxy group. Table 1 below traces the path of estimated ROE changes from his 10.5 percent thinking to my model's 9.2 percent result.

Table 1 – ROE Changes
From: Zepp (10.5%) – To: Staff (9.2%)

Change	ROE
PGE/1200 Zepp/12 Overview[1]	10.50%
PGE/1200 Zepp/26 with 6.0% LT Growth Rate and Peer Utilities	9.90%
Staff Model Y with 6.0% LT Growth and Zepp Peer Utilities	9.90%
Staff Model Y with 6.0% LT Growth and Staff Peer Utilities	9.87%
Staff Modeling with Staff LT Growth and Staff Peer Utilities[2]	9.20%

Q. How is your testimony organized?

A. My testimony is organized as follows:

1 The 10.5 percent estimate is what Dr. Zepp arrives at when he takes all of his analysis (not just the DCF) into account.

2 Staff Long Term Growth rates are provided in Table 5.

Q. Did you prepare exhibits in support of your opening testimony?

A. Yes. I prepared the following exhibits:

Staff/202 .... Staff Peer Screening

Staff/203 .... Staff Three Stage DCF Modeling

Staff/204 .... Staff Synthetic Forward Curve TIPS Analysis

Staff/205 .... Staff Historical GDP Analysis with BEA Data

Staff/206 .... Representative GPD Growth Projections

Q. Does Staff's recommended ROE meet appropriate standards?

A. Yes. Assuming the other cost elements of the rate case are also well founded, the 9.2 percent ROE I recommend meets the *Hope* and *Bluefield* standards, as well as the requirements of Oregon Revised Statue (ORS) 756.040. My recommendations are consistent with establishing "fair and reasonable rates" that are both "commensurate with the return on investments in other enterprises having corresponding risks" and "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital."[3]

Q. Are these the same standards discussed in PGE's testimony?

A. Yes. Staff and PGE apply the same legal standards. However, PGE and Staff disagree on what ROE is commensurate with that of other utilities and other investment opportunities with risk exposure similar to PGE's. Staff

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[3] *See* ORS 756.040(1)(a) and (b).

believes that when investors' expected rate of return is measured using a reasonable expectation of long-term growth, and when risk is measured using an appropriate peer group of utilities, the resulting ROE is within the range recommended by Staff.

COST OF COMMON EQUITY / RETURN ON EQUITY

Q. Did you prepare tables showing current, PGE proposed and Staff proposed overall cost of capital?

A. Yes, the following tables provide that information.

Table 2

Currently Authorized (UE 262 Order No. 13-459)			PGE
Component	**Percent of Total**	**Cost**	**Weighted Average**
Long Term Debt	50.00%	5.541%	2.771%
Preferred Stock	0.00%	0.000%	0.000%
Common Stock	50.00%	9.750%	4.875%
	100.00%		**7.646%**

Table 3

PGE Proposed (UE 283)		PGE/1100 Table 1 Hager-Valach-Greene / 4		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	50.00%	**5.557%**	2.779%	**0.133%**
Preferred Stock	0.00%		0.000%	
Common Stock	50.00%	**10.000%**	5.000%	
	100.00%		**7.779%**	

Table 4

Staff Recommended – UE 283		Opening Testimony (Inclusive of Equity Flotation Costs)		
Component	**Percent of Total**	**Cost**	**Weighted Average**	**ROR vs. Current**
Long Term Debt	**50.00%**	*	*	
Preferred Stock	0.00%		0.000%	*
Common Stock	**50.00%**	**9.200%**	*	
	100.00%		*	

* Capital Structure, and LT Debt will be addressed in separate testimony in support of a partial stipulation.

Q. Describe the analysis underlying Staff's ROE recommendation.

A. I rely on two different multistage DCF models,[4] applied using a cohort group of peer utilities, to estimate the expected return on common equity required by PGE investors. I compare the results of my DCF analysis with national historical electric utilities' authorized ROE values as a check on the reasonableness of my ROE estimates. I also input parameters from some of the models used by Dr. Zepp into Staff's models and contrast the analytic results with Dr. Zepp's results and with results from my two DCF models using Staff's inputs.

Q. What is a DCF model?

A. A DCF model estimates the cost of equity by determining the present value of the future cash flows that investors expect to receive from holding common stock. The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price appreciation. The return on

[4] *See*, in Docket No. UE 115, the Commission's discussion of multistage versus single-stage DCF models in Order No. 01-777 at page 27.

equity under the DCF model is the rate that equates the current stock price and expected cash flows to investors. (Order No. 01-777 at 26.) A DCF model has three primary components: a current stock price, an expected dividend, and an expected growth rate in dividends. (Order No. 07-015 at 32.)

Q. Describe the two DCF models that you used.

The first is a conventional three-stage Discounted Dividend Model, which Staff denotes as a "30-year Three-stage Discounted Dividend Model with Terminal Valuation based on Growing Perpetuity" (hereinafter referred to as "Model X"). The second is the "30-year Three-stage Discounted Dividend Model with Terminal Valuation Based on P/E Ratio" (hereinafter referred to as "Model Y").

Both models require, for each proxy company analyzed by Staff, a "current" market price per share of common stock, estimates of dividends per share to be received in the years 2014 through 2018, annual rates of dividend growth from 2019 through 2023, and a long-term growth rate applicable to dividends beyond 2023.

The three stages of the models are: 1) 2014-2018, where I use Value Line's forecasts of dividends per share for each company; 2) 2019-2023, wherein the rate of dividend growth converges from the average rate over the 2014-2018 period to the growth rate in of the third stage; which is, 3) 2024-2043. Model X includes a terminal value calculation, in which I assume dividends per share grown indefinitely at the rate of growth in Stage 3 ("growing perpetuity"). In contrast Model Y terminates in a sale of stock wherein the price is determined by my escalated price/earnings (P/E) ratio.

Q. Why did you use five years for Stages One and Two, and about 15 years for Stage Three?

A. I presume a 25-30 year horizon is relevant for investors. This is consistent with long standing Staff practices including those of former Staff member, Steve Storm in the NW Natural general rate case of Docket No. UG 221, which the Commission adopted in Order No. 12-408. This time frame allows for investor consideration of 30-year U.S. Treasury Long Bond and other alternate investment opportunities. I use five years for Stage One as that is the timeframe for which Value Line (VL) estimates of future dividends are available. I use five years for Stage Two as that seems a reasonable length of time for individual companies' dividend growth rates that are materially different from the growth rate used in Stage Three (and common to all companies) to converge to a LT dividend growth rate more representative of all electric utilities. I discuss the mechanics of this convergence below. I use 15 to 20 years for Stage Three, corresponding to forward projections from federal sources, and calculate a terminal valuation for the sale of the Company's stock in 2042.

Q. How do you address dividend timing?

A. Each model uses two sets of calculations that differ in the assumed timing of dividend receipt. One set of calculations is based on the standard assumption that the investor receives dividends at the end of each period.

The second set of calculations assumes the investor receives dividends at the beginning of each period. Each model averages the unadjusted ROE values[5] produced with each set of calculations for each peer utility. This approach more closely replicates the "real world" quarterly receipt of dividends by investors; i.e., it takes into account the time value of money.

Q. What accounts for differences in peer capital structures?

A. Each model employs the Hamada equation to calculate an adjustment for differences in capital structure between each peer utility and the PGE proposed and Staff-assumed capital structure for Portland General Electric.[6] When few peer utilities are available, the Hamada equation offers greater material adjustments.

In this case, where many peer electric utilities are available, Staff's screening yields peers sufficiently close to the Company's capital structure that the Hamada equation adjustments are less dramatic.

Q. What price do you use for each peer utility's stock?

A. I use the average of closing prices for each utility from the first trading day in January, February, and March 2014.

Q. Did you review the impact of using prices from any other day of these months?

A. No.

Q. How do Staff's two DCF models differ?

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5 The technical term for each of these estimates is the "internal rate of return," or IRR.

6 Staff describes this adjustment in recent cost of capital testimony. See, as an example, Staff's description in Docket No. UE 233 Exhibit Staff/800, Storm/54 through Storm/57.

A. Model X uses the calculation of a growing perpetuity as part of the terminal valuation in 2043. This may be the most common approach used in multistage DCF models.

Model Y uses the current price-earnings (P/E) ratio[7] multiplied by the estimated earnings per share (EPS) in 2043, which establishes the stock's "selling price" in 2043 for terminal valuation. I estimate the 2043 EPS analogously with methods used to estimate the 2043 dividend in both models; i.e., based on VL estimates to which multiple growth rates are sequentially applied.

Q. What is the purpose of Model Y?

A. I followed Staff's practice in recent rate cases of including this model as a method by which to incorporate the fact that most companies have estimates of future EPS and future dividends growing at different rates. Utilizing EPS that grows on a separate trajectory than dividends is the foundation for an alternative means of terminal valuation.[8]

PEER SCREEN

Q. How did you select comparable companies (peers) to estimate PGE's ROE?

A. I used companies that meet the following criteria as peer utilities to the regulated electric utility activities of Portland General Electric:

7 "Current" in this context means the price obtained, as previously described, divided by Value Line's estimated 2014 earnings per share (EPS); i.e., it is a forward P/E, not an historical P/E.

8 Please note that the approach used in this second model is not the same as using a singular estimate of the growth rate in EPS as the growth rate in dividends.

1. Covered by VL as an Electric Utility;[9]
2. Forecasted by VL to have Positive Dividend Growth;
3. S&P LT Issuer Credit Rating from S&P of BB+ to BBB+;
4. No Decline in Annual Dividend in Last Five Years Based on SNL;
5. Has 80 percent or greater Regulated Assets According to EEI;[10]
6. Has 45 percent to 55 percent LT Debt in VL Capital Structure;[11] and
7. Has No Recent Merger and Acquisition Activity.

Q. Why do you eliminate companies that are not forecasted to have positive dividend growth?

A. There is evidence that investors find common stock of dividend-cutting utilities less attractive. The FPL Group's Florida Power and Light and Niagara Mohawk Power Corporation stock prices declined sharply after dividend cuts.[12] These real world findings are consistent with Staff's screening out electric utilities that have recently cut dividends.

Q. What cohort of companies resulted from your screens?

A. Please see Staff/203 Muldoon/1-2 for detailed Staff Screens and also for a table that shows the list of peer utilities obtained from Staff screens and those obtained from PGE screens in the current rate case, as well as those obtained by both Staff and PGE in Docket Nos. UE 215 and UE 262.

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9 Staff performed this and next three screens on May 17, 2014.

10 Staff reviewed Edison Electric Institute's "2013 Financial Highlights" January 30, 2014.

11 Staff performed this screen on March 17, 2014

12 An example of investor reaction to dividend cuts is found in The New York Times article, "Niagara Mohawk Stock Dives After Dividend Suspension", published January 25, 1996.

SENSITIVITY ANALYSIS

Q. Are there any Staff peer utilities that very narrowly missed inclusion as a Staff peer utility in this general rate case?

A. Yes, TECO Energy, Inc. (TECO) missed the target capital structure range by a fraction of a percentage point. I ran each of Staff's models with and without TECO. This sensitivity analysis increased my upward reasonable range of ROEs by three basis points. Please see Staff's three-stage DCF modeling in Staff Exhibit 203.

Q. Are there any other reasons why TECO should be excluded as a peer utility?

A. Yes, TECO is acquiring NM Gas for $950 million. However, this information was not made public by the TECO until May 14, 2014.

Q. Did you perform other sensitivities that evaluated the impact of peer selection in this case?

A. Yes, I also ran each of Staff's models imposing a mid-capitalization (Mid-Cap) size screen of between two and ten billion dollars capitalization reflecting PGE's financial size. This sensitivity analysis increased my upward reasonable range of ROEs by an additional 5 basis points over that obtained with the inclusion of TECO as a peer utility.

Q. Does the running of these sensitivities replace or modify Staff's primary screening methods?

A. No. However, the results of my sensitivity analyses inform the Commission.

GROWTH RATES

Q. What is the single most important element of discounted dividend or DCF models when used to estimate investors' required ROE?

A. The estimated rate of growth of future dividends. I refer specifically to the singular growth rate for constant growth DCF models and the long-term growth rate for multistage DCF models such as those I use.

Q. What long-term growth rates do you use in the two DCF models?[13]

A. I used three different long-term growth rates, with different methods employed in developing each.

The first method uses a 50 percent weight applied to the average annual growth rate resulting from estimates of long-term Gross Domestic Product (GDP) by the EIA, the OMB, and the CBO, with each receiving one-third of the 50 percent weight.[14] The remaining 50 percent is the average annual

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[13] Methods used here related to GDP-based growth rates are similar, if not identical to methods Staff has used in past proceedings. See, as an example, Staff's discussion of these methods and, to a limited extent, their conceptual underpinnings in Docket No. UE 233, at Exhibit Staff/800, Storm/46 line through Storm/52 line 14.

[14] The EIA is the Energy Information Administration within the U.S. Department of Energy, OMB is the Office of Management and Budget, and CBO is the Congressional Budget Office. EIA and OMB's estimates are of nominal GDP. I applied to CBO's estimate of real GDP an inflation rate for the relevant timeframe developed using the Treasury Inflation-Protected Securities (TIPS) method described by Staff in testimony in multiple recent general rate case proceedings. See, as an example, in Docket No. UE 233 Exhibit Staff/800, Storm/50 line 4 through Storm/51 line 3. The TIPS forecast of annual inflation over the relevant Stage 3 timeframe is 2.35 percent, based on an averages of interest rates for each of the months of October 2013, November 2013, and December 2013. It may be useful to think of the TIPS inflation rate forecast as a forward curve of dollars; i.e., market-based estimates of what a dollar will be worth in the future.

historical real GDP growth rate, established using regression analysis, for the period 1980 through 2013,[15] to which I apply the TIPS inflation forecast.

The second long-term growth rate for Stage 3 dividends is the average annual historical real GDP growth rate, established using regression analysis, for the period 1980 through 2013, to which I apply the TIPS inflation forecast.

The third Stage 3 annual growth rate, which I use primarily for illustrative purposes, is the Indiana / Top 10 Blue Chip most optimistic upper book-end projection.[16]

Q. What are the values for these growth rates?

A. Please see Table 5 below.

Table 5

Stage 3 – Long-Term Annual Dividend Growth Rate					
Component	**Real Rate**	**TIPS Inflation Forecast**	**Nominal Rate**	**Weight**	**Weighted Rate**
EIA			4.89%	16.70%	0.82%
OMB			4.61%	16.70%	0.77%
CBO			4.55%	16.70%	0.76%
Historical 1980 – 2013	2.93%	2.35%	5.35%	50.0%	2.67%
Composite				100%	**5.02%**
Historical 1980 – 2013 Q4			5.35%	100.0%	**5.35%**
Indiana / Top 10 Blue Chip			5.78%	100.0%	**5.78%**

15 Staff discussed this approach in recent Staff cost of equity testimony in several rate case proceedings. See, as an example, in Docket No. UE 233 Exhibits Staff/800, Storm/46, line 15 through Storm/50 line 3.

16 *See* UE 262 PGE /1200, Zepp/30 lines 9 through 10 for a comparison.

Q. What are the material trends in the growth inputs resulting in these long-term growth rates?

A. There are three material change drivers from PGE's last general rate case:

1) Historical GDP rose 6 bps largely due to inclusion of creative works, etc., back to 1929;

2) Investors' expectation of inflation dropped 15 bps; and

3) The US Social Security Administration (SSA) projects lower population growth and no delayed productivity surge following the 2008 great recession.

In aggregate, these drivers narrow expectations, and lower highest expected GDP growth. This is consistent with US Congressional Budget Office (CBO) findings.

Q. Projections of declining growth rate and their relationship to expected long-term GDP growth are a bit opaque and lengthy. Please provide a more approachable summary regarding these findings.

A. See the article in the May 9, 2014, edition of the *Oregonian,* "Fear of Economic Blow as Births Drop around World" by Associated Press business writer, Bernard Condon:

Table 6 – Newborn Numbers:

The financial crisis of 2008-2009 triggered more than a stock market and housing crash. It sent birth rates around the world tumbling too

Here is a look at changes by country:

Country	2008 (Millions)	2012 (Millions)	Percent Change
U.S.	4.250	3.950	– 7.0
France	0.829	0.823	– 1.0
Germany	0.683	0.674	– 1.3
Japan	1.090	1.040	– 5.0

Q. How does the decline in birth rates trigger a future economic slowdown?

A. According to the article, "The effects on economies, personal wealth and living standards are far reaching. A return to "normal" growth is unlikely. Economic growth of 3 percent a year in developed countries, the average over four decades, had been considered a natural rate of expansion, sure to return once damage from the global downturn faded.

But many economists argue that that pace can't be sustained without a surge of new workers. The Congressional Budget Office has estimated that the U.S. economy will grow 3 percent or so in each of the next three years, then slow to an average 2.3 percent for next eight years, the main reason: not enough new workers."

See also, the *Wall Street Journal* articles "Global Growth Worries Climb," of May 16, 2014, "GDP Contracted at 1% Pace in First Quarter," "US Government Bonds Pull Back," and "In Big Economies, Interest Rates Fall as Growth Outlook Turns Cloudier" of May 29, 2014. The articles conclude that inflation is proving lower, the housing market weaker, and the Federal Reserve more likely to hold rates near zero longer than market analysts expected a year ago. In general, there continues to be a pronounced, pervasive and persistent downturn in expected GDP growth.

Q. Is there some way to reconcile predictions regarding slowed economic growth from sources such as those you describe above and Dr. Zepp's six percent terminal growth for three stage DCF models?

A. No.

Q. Is it appropriate to use estimates of long-term GDP growth rates to estimate future dividends for electric utilities?

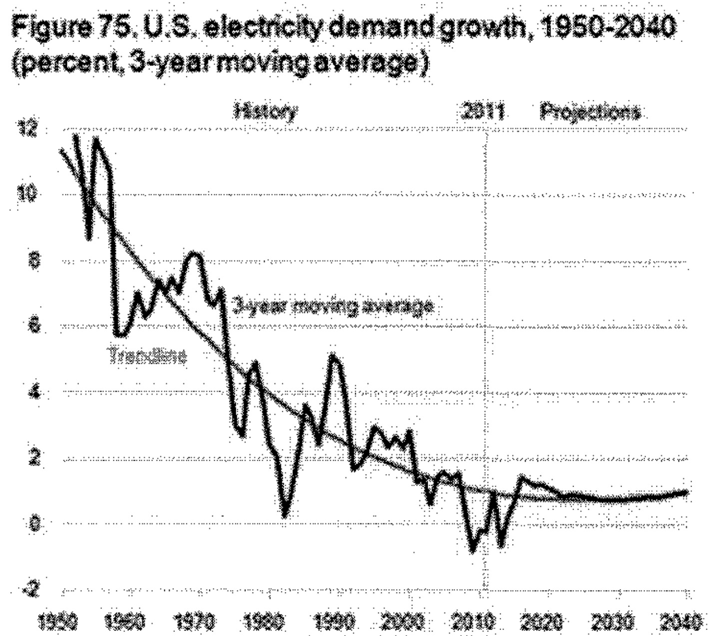
A. Yes. Based on information from the U.S. Energy Information Administration (EIA), electricity use per 2005 dollar of GPD has been declining over the past 30 years and EIA expects the decline to continue through 2040.[17] EIA attributes this decline in the growth of electricity usage in part to more efficient appliances and equipment. Total electricity demand grows by just 0.9 percent per year in EIA's primary projection. See Staff Figure 1 – EIA Figure 75.

Q. Please Summarize.

A. EIA projects GDP will grow at an average of 2.5 percent from 2011 through 2040. However, EIA projects both delivered residential electricity use and separately delivered electricity use for all sectors combined to grow in the same period at an average of only 0.70 percent, without factoring in electricity losses expected to grow 0.4 percent per year on average over this period. See Figure 2.

[17] Staff accessed EIA's "Annual Energy Outlook, at http://www.eia.gov/forecasts/aeo/MT_electric.cfm#growth_elec

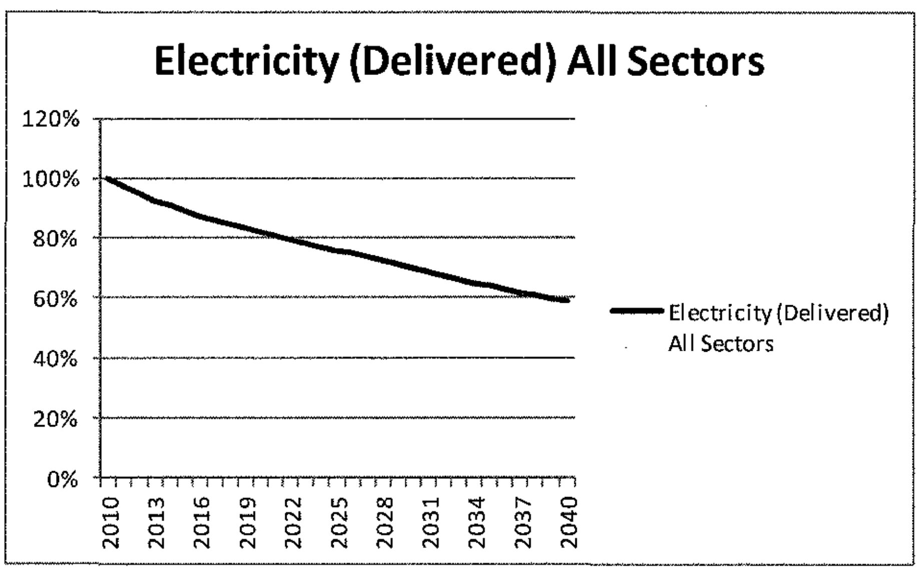
Staff Figure 1 – EIA Figure 75



Staff Figure 2

Delivered Electricity as Percent of GDP

Proportional to 2010



Q. Do you use an annual rate of long-term growth less than that estimated for GDP, given the EIA's outlook for the industry, as illustrated In Figures 1 and 2?

A. I do not, which is another of the reasons my recommended ROE is perhaps overstated.

Q. What are the results of your multistage DCF models?

A. Please see Staff Exhibit 203 for a summary followed by modeling detail.

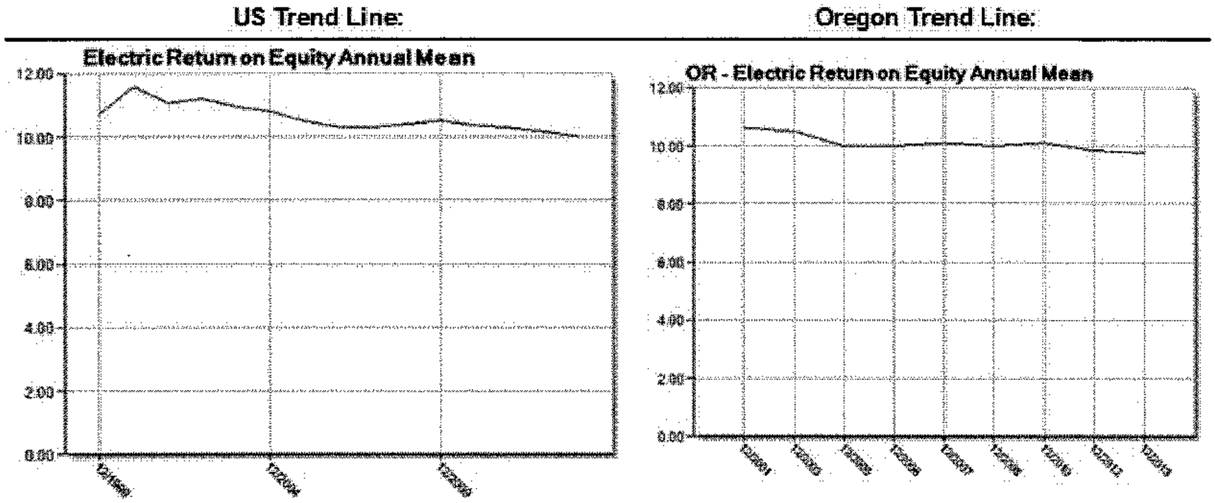
Q. How do these estimated ROE values compare with national historical electric utilities' ROE values?

A. These estimated ROEs are low compared with regulated utilities' authorized return on equity capital in some prior periods. At the same time, the bond market is forecasting, through nominal Treasury bond yields versus TIPS bond yields, an annual inflation rate of 2.35 percent over the 20 year period beginning in 2023, the first year in Stage 3 of the DCF models, through 2043. This low expectation of inflation rates is corroborated by data extractions from the Saint Louis Federal Reserve performed by Staff on March 20, 2014.

Q. How do these estimated ROE values compare with the ROE values for other utilities?

A. In an April study entitled "Major Rate Case Decisions – January-March 2014", SNL Energy affiliate Regulatory Research Associates (RRA) indicated that average ROE for electric utilities in 2013 was 10.02 percent down from 10.24 percent a year ago (21 observations), in line with the perception that there has been a 20 bps decline on average in ROE's as shown below in Figure 3.

Figure 3 – SNL ROE Trends



Q. Virginia statutes authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects. What is the current trend after controlling for Virginia ROE premiums?

A. Excluding four Virginia surcharge/rider generation cases from the data, the average recent authorized electric ROE drops to 9.75 percent.

Historically, PGE has had authorized ROEs as low as 66 bps below the national average and as high as 116 bps above the national average. The upper range of my recommended ROE overlaps the first quarter national average authorized electric utility ROE, excluding Virginia ROEs with embedded incentives. As Oregon has no embedded incentives, it is reasonable to exclude Virginia incentive ROEs from the benchmark.

Q. What is your recommended ROE for PGE inclusive of flotation costs?

A. I recommend an "all-in" ROE of 9.2 percent and provide the Commission a recommended range for consideration of 8.8 percent to 9.6 percent.

Q. What is the Company's requested ROE?

A. PGE asks for an authorized ROE of 10.0 percent.

Q. Have you reviewed Dr. Zepp's discussion and recommendations related to the Company's requested ROE?

A. I have. Dr. Zepp's analysis includes constant growth (single stage; Gordon growth) DCF modeling, two-stage DCF Modeling, risk premium estimates, and a variety of outboard considerations regarding risk, in addition to three-stage DCF analysis.

Q. What is your assessment of Dr. Zepp's DCF analysis and results?

A. Dr. Zepp growth rates are not realistic and do not reflect mainstream estimates. Staff recommends the Commission use the more realistic expectations melded in Staff's modeling.

Q. The Commission's decision regarding a just and reasonable point value for ROE may hinge on growth rates. Did your analysis include the construction of a synthetic forward curve using UST TIPS break even points?

A. Yes. My forward curve is provided in Staff Exhibit 204, reflecting implied market-based inflationary expectations. Staff's recommendations are consistent with market activity indicating investor expectations of future inflation.

Q. What if one ignored current downward adjustments by a broad spectrum of federal agencies and presumed future US GDP growth would look like the past 30 years – Would a ROE based on that assumption fall within Staff's recommended range?

A. Yes, Staff extracted and ran regression on 1980 through 2013 data from US BEA to generate the annual real historical GDP growth rate shown in Table 5. Staff's recommended range of ROEs includes values presuming GDP growth over the next thirty years would look like that of the past 30 years?

However, both the US White House and Congress as well as myriad federal experts expect long term GDP growth to be less than the 5.38 percent extrapolation of historical GDP growth. A conservative projection would therefore be lower than GDP growth over the last several decades, not higher.

Q. Does Staff show this analysis in its exhibits?

A. Yes. Staff Exhibit 205 shows Staff's analysis in support of this finding.

Q. And Staff's positions are corroborated by Federal Sources?

A. Yes. Please see Staff Exhibit 206 for a representative sample.

Q. If utilities' dividends and earnings per share are growing at a faster rate than growth for the whole economy, then utilities would become a bigger part of the economy. Is that happening?

A. No. Electric utilities are not becoming a larger and larger part of the U.S. economy according to Standard and Poor's GICS Sector Scorecard of April 4, 2014 in Figure 4 below.[18]

Figure 4 – Utilities' Share of S&P Market Index

MARKET REPRESENTATION	2007	2008	2009	2010	2011	2012
Utilities	3.62%	4.19%	3.71%	3.30%	3.87%	3.43%

Q. What is the second key concern with Dr. Zepp's DCF modeling?

A. The second concern is with his screening methodology for selecting proxy utilities. From the last PGE general rate case to Docket No. UE 262, Dr. Zepp appears to have heavily revised his screening criteria. Staff very rarely revises screening criteria. There are changes in both Dr. Zepp's and Staff resultant peer utilities. However, in Staff's case, this is the result of applying the same consistent, robust methodology in which the Commission has confidence, and then observing the result.

Q. What do you recommend to the Commission regarding Dr. Zepp's results from his constant growth and two-stage DCF models?

A. Dr. Zepp's constant growth DCF model offers little to inform the Commission in this case. For example, the Commission rejected consideration of parties' constant growth DCF models in Docket No. UE 115.[19] I recommend the Commission give little weight to the results of Dr. Zepp's model. I also recommend that the Commission place little weight on results from his two-

[18] Staff accessed Standard and Poor's sector data on June 3, 2014 at: http://us.spindices.com/indices/equity/sp-500.

[19] *See* page 27 of Order No. 01-777. See also page 24 of Order No. 01-787 in Docket No. UE 116.

stage DCF model. The two-stage DCF model has no transition period between what is happening in the current forward looking period and the final period. This presumes that current trends suddenly and instantly adjust to long-term trends. This presumption is unrealistic. As noted "In "Principles of Corporate Finance", 10th Edition by Brealey, Myers, and Allen,[20] "[i]n real life the return on equity will decline gradually over time."

The three-stage DCF model inserts this transition period, which provides the gradual rather than abrupt change between growth rates.

Q. How do Staff's methods employed in this case differ from those utilized by Staff in PGE's prior general rate cases, UE 262 and UE 215, and by Staff in the recent Northwest Natural Gas Company rate case, UG 221?

A. I examine several sensitivities that have the effect of increasing the upper range of my range of ROE reasonableness. I also examine one adjustment for common equity flotation costs that may shift my entire range of reasonable ROEs upward by as much as 15 bps. Otherwise my methods and modeling are very similar to those employed by Staff in recent general rate cases.

Q. What changes does Staff see in modeling inputs for recent GRCs?

A. Federal estimates of GDP growth whether short-, medium-, or long-term are down from a year ago. Federal estimates of population growth over all three time frames are also down. And no bounce following the economic downturn

[20] "Principles of Corporate Finance", 10th Edition by Brealey, Myers, and Allen, p 85.

of 2008 has occurred.[21] Meanwhile low fixed income returns and losses in 2013 heighted investment in steady dividend stocks.[22]

ALTERNATIVE MODELS EXAMINED

Q. What control modeling does staff perform to corroborate DCF results?

A. I examine several alternative models that support Staff's DCF modeling. While I do not recommend any alternate approach replace the Commission's reliance on three-stage DCF modeling, such alternate models offer a check on the reasonableness of Staff's recommendation.

Q. Is your first model examined the same as the company's constant growth DCF model described in PGE/1200, Zepp/19?

A. Yes. However, I note that Brealey, Myers and Allen, in the tenth edition of their textbook "Principles of Corporate Finance" caution that "the simple constant-growth DCF formula is an extremely useful rule of thumb, but no more than that."[23] Nevertheless, using the Company's inputs and methods, this model suggests PGE's benchmark cost of common equity is in the neighborhood of 9.6 percent.

Staff's three-stage DCF results of 9.2 percent point required ROE as the midpoint in a range of 8.8 percent to 9.6 percent includes the simple constant growth DCF result. The results of the single-state DCF model may show that a reasonable point value might shift upward somewhat from Staff's mid-point

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[21] "Economy Starts Year with Whimper" by Eric Morath and Ben Leubsdorf, WSJ, May 1, 2014.

[22] "Investors Just Want to Get Paid" by Richard Barley, WSJ, Monday, May 12, 2014.

[23] "Principles of Corporate Finance", 10th Edition by Brealey, Myers, and Allen, p 83.

estimate, toward 9.6 percent – the upper end to the range of reasonable and supportable ROEs for PGE, absent other considerations.

Q. Did you examine Dr. Zepp's equity risk premium findings in PGE/1200, Zepp/30-38?

A. Yes I did. However, I found the results, set forth below, high unlikely:

Risk premium 1 ("average of actual ROEs"): 10.2 to 11.4 percent;

Risk premium analysis 2 ("market approach"): 10.8 to 11.2 percent;

Risk premium analysis 3 ("authorized ROEs"): 10.4 percent; and

Risk premium analysis 4 ("Dr. Morin variant of authorized ROEs): 10.5 percent.

Q. Why should Dr. Zepp's findings indicating a cost of equity between 10.2 and 11.4 percent be given little weight?

A. The Research Foundation of CFA Institute, an impartial non-profit organization, published "Rethinking the Equity Risk Premium" in 2011. Herein, Professor Roger Ibbotson of the Yale School of Management and other earlier examiners of how best to approach and calculate equity risk premiums share their current thinking and findings.

"In the 85 years covered by the Ibbotson data, stocks delivered a real return of 6.6 % against 2.1 % for bonds, supporting a 4.5% equity risk premium."[24] Adding that 4.5 percent to Dr. Zepp's 4.41 percent long-term UST rate for 2015 to 2016, would suggest that an investor looking just for a

[24] "Rethinking the Equity Risk Premium," p 81.

quick rough estimate should demand about an 8.9 percent ROE to be satisfied to own a stock of average risk in 2015 to 2016.

Q. PGE is a regulated utility that just had a credit rating increase, is self-building multiple generation plants, and enjoys various revenue smoothing and guaranteeing mechanisms. Is PGE really riskier than the average electric utility, as well as riskier than the average publicly traded U.S. stock, as Dr. Zepp asserts?

A. The Company describes near term uncertainty in economic outlook in terms that obfuscate how extraordinarily favorable to regulated utilities both debt and equity capital markets are at this time. Common sense tells us that PGE is reflective of peer electric utilities of like size and material statistics. PGE is without doubt less risky than the average publicly traded US stock.

With respect to the requested 10.0 percent ROE in the Company's filing, I recommend to the Commission my point estimate of 9.2 percent ROE within a range of 8.8 percent to 9.6 percent cost of equity as better constructed to reflect the return required at this time by investors in PGE's common stock. Staff's 8.8 percent at the lower end of its range of ROEs is supported by an investor's quick check of applying Professor Ibbotson's equity risk premium to expected forward long-term US Treasuries. The ten basis points lower value would be consistent with the fact that PGE is less risky than the average publicly traded US stock.

Q. What do these rough alternative modeling methods, which are regularly used by investors for ballpark calculations, indicate?

A. Investors applying the simple constant-growth DCF formula see a recommendation of the top end of Staff's range of reasonable ROEs. Investors applying Ibbotson equity premium thinking see a recommendation for the lower end of Staff's range of reasonable ROEs. And persons applying the full spectrum of supported growth rates from A) historical to, B) composite historical and federal government forward looking, to C) optimistic top 10 Blue Chip in Staff's three-stage DCF models see that same range of 8.8 percent to 9.6 percent with a recommended midpoint of 9.2 percent.

Q. Are you saying that Staff's range of reasonable ROE's runs from conservative to optimistic supportable expectations for growth, from quick on the fly equity premium models to quick on the fly constant growth models and needs few if any outboard – after the fact, adjustments?

A. That is correct. It is reasonable to think of the simple constant-growth DCF formula and equity risk premiums models as small focusing scopes used to line up a more powerful telescope. Other than an adjustment to address equity flotation cost, Staff's range of 8.8 percent to 9.6 percent with a recommended midpoint of 9.2 percent is reasonable and well supported.

EQUITY FLOTATION COSTS

Q. Is Staff continuing to analyze a potential upward adjustment to ROE to account for equity flotation costs?

A. Yes, Staff continues to investigate this issue, within this rate case.

Q. How has the Commission historically approached equity flotation costs?

A. Historically the Commission has variously 1) used Staff's proposed ROE adjustment, 2) allowed utilities to amortize future test year common equity flotation costs, or 3) declined to recognize common equity flotation costs. Staff is investigating whether an upward adjustment to ROE may be consistent with Oregon statutes, rules, and Commission policy.

Former Staff, Thomas Morgan, recommended no recognition of equity flotation costs unless: A) the stock issuance purpose is to finance long-lived utility property; and B) the amount of the common equity flotation is material to the calculation of ROE (not lost in the rounding).[25] Mr. Morgan argued that the cost of issuing equity already in the capital structure is sunk and merits no adjustment. This thinking on the subject, summarized in Figure 5, is a potential starting point for the Commission to consider the issue in this rate case.

Figure 5 – Staff Proposed Equity Flotation Framework

- ☐ Amount of common equity flotation is material to ROE calculation, i.e., not lost in rounding;
- ☐ Stock issuance purpose is to finance long-lived utility assets; and
- ☐ The Company plans a common equity future flotation before end of test year. (Historical flotation costs are sunk costs.)

[25] See Oregon's response to the Washington Utilities and Transportation Commission's March 2006 survey "Summary Flotation Cost Ratemaking Treatment".

Q. Is Staff aware of any finance or economic text that recommends that the cost of equity flotation be addressed outside the cost of capital?

A. No. Regulatory finance and economic texts that Staff examined offered various remedies within the calculation of cost of equity to address the cost for floating common equity rather than adjustments elsewhere. This treatment suggests that calculations within CoC are adequately able to address the costs of issuing common stock.[26]

Q. How does Staff translate the Company's estimated flotation costs into basis points of ROE?

A. PGE estimates its flotation costs for common equity that the Company plans to issue before the end of the test period for this rate case to be $13.125 million or about 3.5 percent of issuance.[27] Amortization of this issuance cost over 30 annual periods is consistent with the long life of common equity as well as the Company's financing of long lived utility assets.

For example, the above calculation yields an annual cost of between $1.10 million per year or 4.09 bps ROE discounted at Staff's recommended 9.2 percent ROE, and $1.17 million per year or 4.35 bps ROE discounted at PGE's currently authorized 10.0 percent ROE. Staff rounds this result up to 5 bps ROE.

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[26] For example, in "New Regulatory Finance", Roger Morin, Ph.D. recommends various methods for the calculation of and recognition of common equity flotation costs within ROE calculations. Staff recommended adjustment offers the integrity of calculation within ROE, without imposing any greater complexity than necessary to insure just and reasonable rates.

[27] Note that PGE's estimate of issuance costs closely approximate the above cited textbook Table 10-2's 3.48 percent estimate of flotation costs for a like size flotation of common equity.

Q. Is Staff's recommendation regarding flotation cost ready for Commission review at this time?

A. No. Staff has examined three approaches to addressing recent equity flotation cost within the cost of equity:

1. Approximately 5 basis points (bps) ROE applied over 30 years;
2. Approximately 15 bps ROE applied over 5 years;
3. No adjustment – treating the equity flotation with forward as sunk costs.

Q. What placeholder does Staff include in its recommended ROE at this time?

A. Staff includes 13 bps addressing equity forward and flotation costs in its recommended range of reasonable ROE's. This allows the Commission to see Staff's highest recommended ROE, inclusive of equity floatation costs.

Q. Were Staff to recommend one of the other approaches to addressing Equity Flotation Costs, would Staff's recommended range of ROE's shift downward?

A. Yes.

EQUITY FORWARD

Q. Has Staff carefully analyzed PGE's equity forward?

A. Yes. Staff has reviewed the confidential cost profile of the Company's equity forward against alternatives that PGE considered.

Q. Has Staff formed any general conclusions regarding equity forwards as a result of this analysis?

A. No. Each equity forward requires careful consideration prior to execution. In PGE's specific context, in this instance, the equity forward 1) assured Company, investors and ratepayers of certainty in the range of generated proceeds; 2) delayed the impact of draw down on funds until cash was needed for utility purposes; 3) added flexibility to offset the Company's temporary inability to issue First Mortgage Bonds (FMB);[28] and 4) was appropriate to the unique market conditions at time of issuance.

Q. Staff recommends the Commission find PGE's equity forward prudent in the current instance, but in no way precedent setting?

A. Yes. PGE's positive current equity forward arrangement and execution to date afforded high certainty at controlled cost and risk, particularly when bolstered by Commission flexibility with regard to 2014 debt issuances, within current market conditions. However, future conditions will vary.

<u>OUTBOARD ADJUSTMENT OF MODELING RESULTS</u>

Q. Dr. Zepp argues against a 10 bps reduction in ROE for PGE's risk reduction through decoupling and for a risk premium of 10 basis points due to PGE'S exposure to wholesale markets. Does Staff recommend the Commission make any outboard adjustments other than possibly for equity flotation costs?[29]

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28 Three forced outages put temporary pressure on PGE cash flows and interest coverage ratios.

29 For comparison see UE 283, PGE/1200 Zepp 18 and UE 262, PGE/1200, Zepp/19 at line 3 to Zepp/21 at line 2.

A. No. In general Staff's peer screening is sufficient at this time to support robust peer analytics with minimal outboard adjustments. Staff finds it more plausible that PGE has risk characteristics similar to an electric utility of like statistical dimensions, than that PGE is either materially more or materially less risky than its close peer electric utilities.

Q. In Order No. 09-020, the Commission concluded that the adoption of decoupling justified a ROE reduction of 10 bps for PGE. Does Staff recommend against this reduction at this time?

A. Yes. At this time, Staff cannot draw broad conclusions on whether cost of equity estimates for PGE's peers already reflect the benefits provided by decoupling or like risk offsetting measures that may be adopted in the future. A recent Brattle Group's report does not detect statistically significant reduction in utility ROEs attributable to decoupling.[30]

Q. Application of the Hamada Equation to un-lever peer utility capital structures and to re-Lever at PGE'S target capital structure increases required ROE by 5 bps. Why is this adjustment reasonable?

A. Staff usually employs the Hamada Equation. As earlier discussed, Staff's screening criteria already identify peers that have very close capital structure to PGE's. Use of the Hamada adjusted results helps insure that Staff has captured all material risk in its analysis.

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[30] "The Impact of Decoupling on the Cost of Capital" by the Brattle Group was released March, 2011 and accessed by Staff on August 30, 2013, at http://www.brattle.com/_documents/UploadLibrary/Upload922.pdf

This recommendation is consistent with Staff's thinking that the underlying DCF methodology is strong and adjustments should be kept to a minimum. In general, I recommend introducing few poorly substantiated adjustments to the three stage DCF modeling that has served the Commission reliably and well in recent years.

EXTRA-JURISDICTIONAL REFERENCES

Q. Dr. Zepp seeks to corroborate various inputs and upward leaps in required ROE by citing proceedings outside Oregon. Is there any reason for the Commission to give any weight to such references?

A. No. Dr. Zepp does not offer a balanced survey of inputs and methodologies. For example, he does not incorporate or reference inputs and methods used in Docket No. UE 130043 before the Washington Utilities and Transportation Commission (WUTC) supporting the WUTC's 9.5 percent ROE for PacifiCorp decided in December of 2013.

Staff suggests that the Company's filing to date identifies no reason to selectively incorporate or favor the proceedings in one neighboring state over those in another.

Q. What assurance does the Commission have that your viewpoint has any practical traction with financial managers and analysts?

A. Warren Buffett defines intrinsic value as: "the discounted value of the cash that can be taken out of a business during its remaining life." For an investor without control of the business, the value of a stock is the discounted value of the cash flows that are realized while that stock is held (dividends), plus the discounted proceeds from any sale of the stock.[31] This approach is dispassionate, is the standard in Oregon, and constructively informs decision making.

Q. Are there other material considerations?

A. Yes. Staff has the benefit of filing testimony at a later date than the Company's initial filing. This can give Staff the opportunity to access more current data feeds and reports not yet knowable to the utility and its expert cost of capital witnesses.

Q. How is this material?

A. Staff had the benefit of knowing, as it filed this testimony, facts like the following, not available earlier to the Company and Dr. Zepp:

1. The US economy generated a retraction of 1.0 percent on May 29, 2014.
2. Federal experts from the White House to the Congressional Budget Office to the Social Security Administration projected lower short-term, medium-term and long-term growth than a year ago. Federal sources also now project lower U.S. population growth in these time frames.
3. UST Yields did not continue to rise in 2013 but rather fell (down about half a percentage point on 10-year UST).[32]

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[31] "Ruminations on Risk" by Michael Mauboussin and Alexander Schay, US Investment Strategy, Valuation Strategy, August 3, 2001. Please note that this publication is supported in part by Credit Suisse and First Boston.

[32] The yield on 10-year UST closed at 2.502 percent on May 15, 2014 according to the WSJ, "Nervous Investors Pile into Bonds" by Min Zeng. In this article, David Kotok, Chairman and Chief Investment Officer at Cumberland Advisers summarizes the lack of bounce following the 2008 economic downturn as: "For years we've heard these monetary policies would drive rates up, inflation would rise and growth would shoot up, and it hasn't happened." The WSJ on May 29, 2014 reported a prior day close for the 10-year UST of 2.440 percent, consistent with Chairman Kotok's point.

4. Relatively high dividend utility stocks benefited from A) investor losses in 2013 fixed income investments, B) Continued Global Crises from Southern Europe to South America to the Ukraine, and C) Global Central Bank injection of money into bond markets – extending a flight to safety and quality.
5. Moody's upgraded PGE credit ratings.
6. Utility merger and acquisitions and stock buy backs picked up, creating competition for dividend payouts, reducing dividend growth rates.
7. Authorized ROEs trended downward in 2013 and 2014 Q1 electric and gas utilities rate cases according to SNL Financial LC.

In summary, conditions remained such that investors have high demand for PGE securities, lowering required returns. For example, investors who lost money in UST TIPS in the second quarter of 2013 continue to find PGE stock and debt attractive substitutes, potentially requiring no greater return than that of investment capital plus dividend. Conversely cyclical industries such as mining are not seeing much growth further increasing the attractiveness of PGE securities.

Q. Does Staff's modeling better reflect current and forward information?

A. Yes. Staff generally relied on 2014 data, while the Company relied in part on out of jurisdiction 2012 information. The Company's exceedingly high growth inputs appear to be vastly overstated and to be the key driver for implausibly high ROE recommendations.

Q. In addition to 65 standard data requests and 20 follow up data requests; did Staff also rely on other party data requests in its analysis?

A. Yes. Staff also relied on 18 ICNU CoC data requests as Staff did its analysis and prepared this testimony.

Q. You have suggested that PGE appears to be no more risky than is captured by Staff's analysis.

A. Yes. If investors saw PGE as fatally flawed and unable to be modeled without after the fact adjustments, they would just pass PGE by and invest in another more attractive utility. Since PGE stock is very high and there is no shortage of demand for PGE bonds, one can presume that investors see PGE as a vertically integrated regulated utility with good prospects, so much so that its credit ratings were recently upgraded by Moody's.

Q. Does that conclude your opening testimony?

A. Yes.

CASE: UE 283
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME:	Matthew (Matt) Muldoon
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Senior Economist Energy Division Rates Finance & Audit Program
ADDRESS:	3930 FAIRVIEW INDUSTRIAL DR SE SALEM, OREGON 97302-1166.
EDUCATION:	In 1981, I received a Bachelors of Arts Degree from the University of Chicago. Then in 2007, I received a Masters of Business Administration from Portland State University with a certificate in Finance.
EXPERIENCE:	From April of 2008 to the present, I have been employed by the OPUC. My current responsibilities include financial and rate analysis in the Energy Division of the OPUC's Utility Program with an emphasis on cost of capital. I have also participated in regional and sub-regional planning including activities with Western Electricity Coordinating Council, Variable Generation Subcommittee, Columbia Grid, Northern Tier Transmission Group (NTTG) and other regional and sub-regional forums focused on transmission and wind integration. From 2002 to 2008 I was Executive Director of the Acceleration Transportation Rate Bureau, Inc. where I developed new rate structures for surface transportation and created metrics to insure program success within regulated processes. I was the Vice President of Operations for Willamette Traffic Bureau, Inc. from 1993 to 2002. There I managed tariff rate compilation and analysis. I also developed new information systems and did sensitivity analysis for rate modeling.
OTHER:	I have prepared, and defended formal testimony in contested hearings before the OPUC, ICC, STB, WUTC and ODOT. I have also prepared OPUC Staff testimony in BPA rate cases.

CASE: UE 283
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 202

Staff Peer Screening

Exhibits in Support
Of Opening Testimony

June 11, 2014

Electric Utilities Screened by Staff and PGE

#	Abbreviated Utility	UE 283 PGE	UE 262 PGE	UE 215 PGE	UE 283 Staff	UE 262 Staff	UE 215 Staff	VL Corporate Name Electric Utility
1	AEP	No	No	Yes	Yes	Yes	Yes	American Electric Power Company, Inc.
2	Allete	Yes	Yes	Yes	Yes	No	Yes	Allete, Inc.
3	Alliant	Yes	Yes	Yes	No	No	No	Alliant Energy Corporation
4	Ameren	No	No	Yes	No	No	No	Ameren Corporation
5	Avista	Yes	Yes	Yes	No	Yes	No	Avista Corporation
6	Black Hills	Yes	Yes	No	No	No	No	Black Hills Corporation
7	Center Point	No	No	No	No	No	No	CenterPoint Energy, Inc.
8	**CH Energy**	**No**	No	No	**No**	No	No	**CH Energy Group, Inc.**
9	Cleco	Yes	Yes	Yes	Yes	Yes	Yes	Cleco Corporation
10	CMS	Yes	Yes	Yes	No	No	No	CMS Energy Corporation
11	Consol Ed	No	No	No	No	No	No	Consolidated Edison, Inc.
12	Dominion	No	No	No	No	No	No	Dominion Resources, Inc.
13	DTE	No	No	Yes	Yes	Yes	No	DTE Energy Company
14	Duke	No	No	Yes	No	No	No	Duke Energy Corporation
15	Edison Int'l	No	No	Yes	Yes	Yes	No	Edison International
16	El Paso	No	No	No	No	No	No	El Paso Electric Company
17	Empire	No	Yes	Yes	No	No	Yes	Empire District Electric Company
18	Entergy	No	No	Yes	No	No	No	Entergy Corporation
19	**Exelon**	No	No	No	**No**	No	No	Exelon Corporation
20	First Energy	No	No	Yes	No	No	No	FirstEnergy Corporation (Formerly in part: Allegheny)
21	Great Plains	Yes	No	Yes	No	No	No	Great Plains Energy Incorporated
22	Hawaiian	Yes	Yes	Yes	No	No	No	Hawaiian Electric Industries, Inc.
23	IDACORP	Yes	Yes	Yes	Yes	Yes	Yes	IDACORP, Inc.
24	Integrys	No	No	No	No	No	No	Integrys Energy Group, Inc.
25	ITC	No	No	No	No	No	No	ITC Holdings Corp.
26	MGE	Yes	Yes	Yes	No	No	No	MGE Energy, Inc.
27	NE Utilities	No	No	No	No	No	No	Northeast Utilities
28	NextEra	No	No	Yes	No	No	No	NextEra Energy, Inc. (Formerly: FPL Group, Inc.)
29	NorthWestern	Yes	Yes	Yes	No	Yes	No	NorthWestern Corporation
30	**NV Energy**	**No**	Yes	No	**No**	No	No	**NV Energy Inc.**
31	OGE	Yes	Yes	Yes	No	No	No	OGE Energy Corporation
32	Otter Tail	No	No	No	No	No	No	Otter Tail Corporation
33	**Pepco**	No	No	No	**No**	No	No	Pepco Holdings, Inc.
34	PG&E	No	No	Yes	Yes	Yes	Yes	PG&E Corporation
35	**PGE**	**Yes**	**Yes**	**Yes**	**No**	**No**	**No**	**Portland General Electric Company**
36	Pinnacle	Yes	Yes	Yes	No	No	Yes	Pinnacle West Capital Corporation
37	PNM	Yes	No	No	No	No	No	PNM Resources, Inc.
38	PPL	No	No	No	No	No	No	PPL Corporation
39	Public Serv.	No	No	No	No	No	No	Public Serv. Enterprise Group, Inc.
40	SCANA	Yes	Yes	No	No	No	No	SCANA Corporation
41	Sempra	No	No	No	No	No	No	Sempra Energy
42	Southern	No	No	Yes	No	No	No	Southern Company, The
43	**TECO**	Yes	Yes	Yes	**No**	Yes	Yes	**TECO Energy, Inc.**
44	UIL	No	No	No	No	No	Yes	UIL Holdings Corporation
45	UNS	Yes	Yes	Yes	No	No	No	UNS Energy Corporation (Formerly: UniSource)
46	Vectren	No	No	No	No	No	No	Vectren Corporation
47	Westar	Yes	Yes	Yes	Yes	Yes	Yes	Westar Energy, Inc.
48	Wisconsin	Yes	Yes	Yes	No	No	Yes	Wisconsin Energy Corporation
49	Xcel	No	No	Yes	No	No	Yes	Xcel Energy, Inc.

Staff Peer Screen

		Continuity Screen	
Small Cap	Under 2 Billion	1	Sensitivity with Teco
Mid Cap	2 Billion to 10 Bil	2	Sensitivity Mid Cap
Large Cap	Over 10 Billion		

#	Abbreviated Utility	UE 283 PGE	UE 283 Staff	VL 3/17/2014 Beta	Yahoo Fin. 3/17/2014 Beta	Yahoo Fin. 3/17/2014 Mkt Cap $ Billions	Covered by Value Line 3/17/2014 (VL)	SNL 3/17/2014 No Div Declines 5 years	S&P 3/17/2014 Local LT Debt Rating	Credit Rating BB+ to BBB+	EEI 1/30/2014 80% Regulated Assets	VL 3/17/2014 LT Debt 45% - 55% of Capital	VL Forecast Div. Growth 5 Yr Rate > 0%	No M&A Detected Activity in Last 5 Years
1	AEP	No	Yes	0.70	0.25	24.53	Yes	Yes	BBB	Yes	80% +	51%	Yes	Nov 1999 Merged w CSR, May 2011 Float
2	Allete	Yes	Yes	0.80	0.78	2.08	Yes	Yes	BBB+	Yes	80% +	45%	Yes	No M&A
3	Alliant	Yes	No	0.80	0.39	6.12	Yes	Yes	A-	No	80% +	48%	Yes	Selling MN Electric & N Gas Dist to Coop Group Announced Apr. 17, 2014 SNL
4	Ameren	No	No	0.85	0.33	9.98	Yes	No	BBB+	Yes	80% +	50%	Yes	Mar 2013,$900M Sale of Merch. Gen. (5 Power Plants) to Dynergy / SNL
5	Avista	Yes	No	0.80	0.57	1.81	Yes	Yes	BBB	Yes	80% +	51%	Yes	Pending M&A - Purchase of AERC Docketed
6	Black Hills	Yes	No	0.90	0.64	2.60	Yes	Yes	BBB	Yes	50% to 80%	43%	Yes	No M&A
7	Center Point	No	No	0.85	0.36	10.40	Yes	Yes	A-	No	50% to 80%	66%	Yes	No M&A
8	CH Energy	No	No	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Feb 2012 Bought by Fortis
9	Cleco	Yes	Yes	0.70	0.39	3.04	Yes	Yes	BBB+	Yes	80% +	46%	Yes	No M&A, Check
10	CMS	Yes	No	0.70	0.14	7.71	Yes	Yes	►BBB	Yes	80% +	67%	Yes	No M&A
11	Consol Ed	No	No	0.65	-0.02	16.12	Yes	Yes	A-	No	80% +	46%	Yes	No M&A
12	Dominion	No	No	0.75	0.06	41.05	Yes	Yes	A-	No	50% to 80%	61%	Yes	No M&A
13	DTE	No	Yes	0.85	0.34	12.75	Yes	Yes	BBB+	Yes	80% +	49%	Yes	Mar 2001 Merged w MCN
14	Duke	No	No	0.70	0.07	50.23	Yes	Yes	BBB+	Yes	50% to 80%	47%	Yes	Jan 2011 Bought Progress Energy
15	Edison Int'l	No	Yes	0.80	0.34	17.07	Yes	Yes	BBB-	Yes	80% +	45%	Yes	Aug 2000 Bought Citizens Power
16	El Paso	No	No	0.70	0.22	1.41	Yes ***	No	BBB	Yes	80% +	55%	Yes	No M&A
17	Empire	No	No	0.75	0.44	1.05	Yes	No	BBB	Yes	80% +	50%	No	No M&A
18	Entergy	No	No	0.75	0.22	11.64	Yes	Yes	BBB	Yes	80% +	56%	Yes	Mar 2013 Merger w FPL Group, Dec 2011 Sold Trans. to ITC
19	Exelon	No	No	0.75	0.17	26.60	Yes	Yes	BBB	Yes	50% to 80%	46%	No	Exelon and Pepco Merger Announced May 7, 2014
20	First Energy	No	No	0.75	0.01	13.35	Yes	Yes	BBB-	Yes	50% to 80%	54%	No	No M&A
21	Great Plains	Yes	No	0.90	0.60	4.12	Yes	No	BBB	Yes	80% +	50%	No	No M&A
22	Hawaiian	Yes	No	0.85	0.19	2.56	Yes	Yes	BBB-	Yes	Under 50%	46%	Yes	No M&A
23	IDACORP	Yes	Yes	0.80	0.62	2.79	Yes	Yes	BBB	Yes	80% +	45%	Yes	No M&A
24	Integrys	No	No	1.05	0.51	4.65	Yes	Yes	A-	No	80% +	39%	Yes	No M&A
25	ITC	No	No	0.70	-0.08	5.70	Yes	Yes	A-	No	N/A	64%	Yes	Dec 2011 Bought Entergy Transmission – 8K Apr 2013 Voted Y
26	MGE	Yes	No	0.70	0.50	1.39	Yes	Yes	AA-	No	50% to 80%	39%	Yes	No M&A
27	NE Utilities	No	No	0.75	0.37	14.22	Yes	Yes	A-	No	80% +	44%	Yes	Oct 2010 Merged w Nstar
28	NextEra	No	No	0.75	0.29	41.28	Yes	Yes	A-	No	50% to 80%	59%	Yes	No M&A, but see Entergy Merger w FPL Group
29	NorthWestern	Yes	No	0.70	0.44	1.79	Yes	Yes	BBB	Yes	80% +	54%	Yes	Large Acquisition Pending $900M to buy 633 MW Hydro Capacity in MT
30	NV Energy	No	No	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	Purchased in 2013 by MEH
31	OGE	Yes	No	0.85	0.55	7.28	Yes	Yes	A-	No	50% to 80%	51%	Yes	No M&A
32	Otter Tail	No	No	0.95	0.92	1.14	Yes	Yes	BBB	Yes	50% to 80%	42%	Yes	No M&A
33	Pepco	No	No	0.80	0.21	5.13	Yes	Yes	BBB+	Yes	50% to 80%	47%	Yes	Exelon and Pepco Merger Announced May 7, 2014
34	PG&E	No	Yes	0.60	0.31	20.42	Yes	Yes	BBB	Yes	80% +	49%	Yes	July 1997 Purchased Valero Energy
35	PGE	Yes	No	0.80	0.44	2.53	Yes	Yes	BBB	Yes	80% +	47%	Yes	No M&A
36	Pinnacle	Yes	No	0.75	0.36	6.11	Yes	Yes	A-	No	80% +	45%	Yes	Pinnacle W's AZ Pub Service (APS) Buying $182 M 4-Corners Coal Gen
37	PNM	Yes	No	0.95	0.27	2.16	Yes	No	BBB	Yes	80% +	51%	No	No M&A
38	PPL	No	No	0.70	0.17	20.66	Yes	Yes	BBB	Yes	50% to 80%	64%	Yes	No M&A
39	Public Serv.	No	No	0.80	0.14	18.62	Yes	Yes	BBB+	Yes	50% to 80%	38%	Yes	No M&A
40	SCANA	Yes	No	0.75	0.28	7.14	Yes	Yes	BBB+	Yes	50% to 80%	54%	Yes	No M&A
41	Sempra	No	No	0.80	0.32	23.56	Yes	Yes	BBB+	Yes	50% to 80%	53%	Yes	No M&A
42	Southern	No	No	0.60	0.02	38.64	Yes	Yes	A	No	80% +	50%	Yes	No M&A
43	TECO	Yes	No	0.95	0.61	3.73	Yes	Yes	BBB+	Yes	80% +	56%	Yes	TECO to Acquire NM Gas for $950 M per SNL, May 14, 2014
44	UIL	No	No	0.85	0.30	2.06	Yes	Yes	BBB	Yes	80% +	59%	No	No M&A
45	UNS	Yes	No	0.70	0.54	2.51	Yes	Yes	N/A	No	80% +	62%	Yes	No M&A
46	Vectren	No	No	0.75	0.43	3.17	Yes	Yes	A-	No	80% +	53%	Yes	No M&A
47	Westar	Yes	Yes	0.80	0.27	4.52	Yes	Yes	BBB	Yes	80% +	51%	Yes	No M&A
48	Wisconsin	Yes	No	0.70	0.18	10.32	Yes	Yes	A-	No	80% +	52%	Yes	No M&A
49	Xcel	No	No	0.65	0.15	15.31	Yes	Yes	A-	No	80% +	53%	Yes	No M&A

CASE: UE 283
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Staff Three Stage DCF Modeling

Exhibits in Support
Of Opening Testimony

June 11, 2014

Required ROE
Results from Three Stage DCF Modeling

Model X: 3 Stage DCF - Dividend Growth with Terminal Value as Perpetuity (Hamada Upward Adjusted)						
X	**Composite Growth**	**5.02%**	**Historical Growth**	**5.35%**	**Blue Chip Growth**	**5.78%**
Staff Peers	8.74%	Implied Average ROE	8.98%	Implied Average ROE	9.29%	Implied Average ROE
Sensitivity 1 w TECO	8.77%		9.01%		9.31%	
Sensitivity 2 Mid-Cap	8.87%		9.11%		9.42%	
Company Elec. Peers	8.69%		8.93%		9.24%	

Model Y: 3 Stage DCF - Dividend Growth with Terminal Value as Sales based upon EPS Growth and Terminal Stock Sale (Hamada Upward Adjusted)						
Y	**Composite Growth**	**5.02%**	**Historical Growth**	**5.35%**	**Blue Chip Growth**	**5.78%**
Staff Peers	8.86%	Implied Average ROE	9.05%	Implied Average ROE	9.30%	Implied Average ROE
Sensitivity 1 w TECO	8.89%		9.07%		9.32%	
Sensitivity 2 Mid-Cap	8.94%		**9.13%**		9.38%	
Company Elec. Peers	8.88%		9.08%		9.33%	

Values Shown Above Are NOT Adjusted for Equity Flotation Costs

Staff Interpretation of ROE Modeling Results

Prior to Addressing Common Stock Flotation Costs:

High Point Estimate:	9.42%	Reflecting a Component Range of:	8.69%	to	9.42%

Note: Company Average Peer Values are encompassed within Staff's Range of Reasonable ROE's

Equity Flotation $ $13.125 Million $0.27 M/bp 48.6 bps

Flotation Cost Adjustment 0.13% **Placeholder**

Upward shift to entire range above Over 5 Years, Discounted at Last Authorized ROE

Including Common Stock Flotation Cost Shown Highlighted Above:

Staff's Recommendations

High Point Estimate:	**9.6%**	Reflecting a Component Range of:	**8.8%**	to	**9.6%**

Mid Point Estimate: **9.2%**

Reasonable Point Estimate

IN / Top Blue Chip Components:

2.90 percent Real GDP is both the Indiana University's Kelley School of Business long range projection accessed by Staff on October 11, 2013 and the longest range, top 10 average projection from June 1, 2013, Blue Chip Financial Forecasts. From that same source, 2.80% CPI is the highest, long-range projection.

Staff will update top referent growth in future testimony.

Federal sources have adjusted growth estimates downward this year. Staff expects the Kelley School of Business will do likewise.

Note: Please see next pages for illustrations of Three Stage DCF calculations.
Staff work papers contain the spreadsheets for these models as well as sensitivities examined.

Staff Model X – Dividend Growth with Terminal Value as Perpetuity

[illegible] Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

Staff Model X

EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
								Initial Stage						Transition Stage				
1	AEP	1	AEP	9.2%	60.2%	0.00	(48.26)	1.95	2.02	2.11	2.20	2.30	2.40	2.50	2.60	2.71	2.82	2.93
2	Allete	2	ALE	8.9%	64.3%	0.00	(50.78)	1.90	1.98	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.76
9	Cleco	3	CNL	9.4%	61.5%	0.00	(48.41)	1.43	1.58	1.71	1.85	2.00	2.15	2.38	2.58	2.82	3.08	3.36
13	DTE	4	DTE	9.2%	61.0%	0.00	(70.64)	2.59	2.73	2.86	3.00	3.15	3.30	3.46	3.66	3.88	4.09	4.31
15	Edison Int'l	5	EIX	8.9%	67.7%	0.00	(51.61)	1.35	1.45	1.59	1.74	1.90	2.08	2.23	2.41	2.59	2.79	3.01
23	IDACORP	6	IDA	9.4%	61.2%	0.00	(54.61)	1.57	1.76	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.76
34	PG&E	7	PCG	9.2%	59.6%	0.00	(43.65)	1.82	1.82	1.91	2.00	2.10	2.20	2.26	2.33	2.40	2.48	2.55
47	Westar	8	WR	8.9%	63.6%	0.00	(34.09)	1.35	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82
				9.1%	62.4%	0.00												

Ticker	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity
	Final Stage																					
AEP	3.10	3.28	3.47	3.67	3.88	4.11	4.34	4.59	4.86	5.14	5.44	5.75	6.08	6.44	6.81	7.20	7.62	8.06	8.52	273.45	9.02	284.43
ALE	2.91	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	280.51	8.45	272.08
CNL	3.55	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	295.04	10.33	284.71
DTE	4.58	4.83	5.11	5.40	5.71	6.04	6.39	6.76	7.15	7.57	8.00	8.47	8.96	9.47	10.02	10.60	11.21	11.86	12.55	399.63	13.27	386.35
EIX	3.18	3.36	3.56	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.58	5.90	6.24	6.60	6.98	7.39	7.81	8.26	8.74	302.89	9.25	293.64
IDA	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.96	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	327.27	11.57	315.70
PCG	2.70	2.85	3.02	3.19	3.38	3.57	3.78	4.00	4.23	4.47	4.73	5.01	5.29	5.60	5.92	6.27	6.63	7.01	7.42	238.38	7.85	231.53
WR	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	188.05	5.60	180.45

BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
								Initial Stage						Transition Stage				
1	AEP	1	AEP	9.4%	57.8%	0.00	(49.26)	2.02	2.11	2.20	2.30	2.40	2.50	2.60	2.71	2.82	2.93	3.10
2	Allete	2	ALE	9.1%	62.1%	0.00	(50.78)	1.98	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.75	2.91
9	Cleco	3	CNL	9.6%	57.9%	0.00	(49.41)	1.58	1.71	1.85	2.00	2.15	2.38	2.58	2.82	3.08	3.36	3.55
13	DTE	4	DTE	9.4%	58.3%	0.00	(70.64)	2.73	2.86	3.00	3.15	3.30	3.46	3.66	3.88	4.09	4.31	4.58
15	Edison Int'l	5	EIX	9.1%	64.3%	0.00	(51.61)	1.45	1.59	1.74	1.90	2.08	2.23	2.41	2.59	2.79	3.01	3.18
23	IDACORP	6	IDA	9.7%	57.6%	0.00	(54.61)	1.76	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.76	3.98
34	PG&E	7	PCG	9.3%	57.6%	0.00	(43.65)	1.82	1.91	2.00	2.10	2.20	2.26	2.33	2.40	2.48	2.55	2.70
47	Westar	8	WR	9.0%	61.6%	0.00	(34.09)	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82	1.93
				9.3%	59.6%	0.00												

Ticker	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity
	Final Stage																					
AEP	3.28	3.47	3.67	3.88	4.11	4.34	4.59	4.86	5.14	5.44	5.75	6.08	6.44	6.81	7.20	7.62	8.06	8.52	9.02	274.62	9.54	265.08
ALE	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	8.45	281.66	8.94	272.92
CNL	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	10.33	293.71	10.93	282.78
DTE	4.83	5.11	5.40	5.71	6.04	6.39	6.76	7.15	7.57	8.00	8.47	8.96	9.47	10.02	10.60	11.21	11.86	12.55	13.27	400.44	14.04	386.39
EIX	3.36	3.56	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.58	5.90	6.24	6.60	6.98	7.39	7.81	8.26	8.74	9.25	301.60	9.78	292.02
IDA	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.96	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	11.57	325.72	12.24	313.48
PCG	2.85	3.02	3.19	3.38	3.57	3.78	4.00	4.23	4.47	4.73	5.01	5.29	5.60	5.92	6.27	6.63	7.01	7.42	7.85	240.83	8.30	232.53
WR	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	5.60	187.26	5.93	181.33

Average IRR of BOY & EOY Cash Flows					Value as	Average 2013 - 2018		
Screen	Staff's Peer Utilities	Set	Ticker	IRR	% of NPV_{DIV}	Dividend Growth Rates	EOY	
1	AEP	1	AEP	9.3%	59.0%	4.4%	4.3%	4.3%
2	Allete	2	ALE	9.0%	63.2%	3.9%	3.9%	3.9%
9	Cleco	3	CNL	9.5%	59.7%	8.0%	8.4%	8.2%
13	DTE	4	DTE	9.3%	59.6%	4.8%	5.0%	4.9%
15	Edison Int'l	5	EIX	9.0%	66.0%	9.2%	8.9%	9.1%
23	IDACORP	6	IDA	9.6%	59.4%	7.6%	8.2%	7.9%
34	PG&E	7	PCG	9.3%	58.7%	4.6%	4.4%	4.6%
47	Westar	8	WR	9.0%	62.6%	2.8%	2.8%	2.8%
	Group Average			9.24%	61.0%			

Staff Model Y – EPS Growth to Determine a Sale Terminal Value

5.75% Annual Growth Rate - Stage 3 | EPS Growth to Determine a Sale Terminal Value | EPS Growth

Staff Model Y

EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV$_{TV}$	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Sale	2043
								Initial Stage						Transition Stage					Final Stage																						
1	AEP	1	AEP	9.4%	62.9%	(0.00)	(49.26)	1.95	2.02	2.11	2.20	2.30	2.40	2.50	2.60	2.71	2.82	2.93	3.10	3.28	3.47	3.67	3.88	4.11	4.34	4.59	4.86	5.14	5.44	5.75	6.08	6.44	6.81	7.20	7.62	8.06	8.52	296.78	9.02	287.77	
			e					3.10	3.30	3.62	3.76	4.00	4.25	4.49	4.74	5.00	5.28	5.58	5.89	6.23	6.59	6.97	7.37	7.80	8.25	8.72	9.23	9.76	10.33	10.92	11.55	12.22	12.93	13.67	14.47	15.30	16.19		17.12		18.11
2	Allete	2	ALE	9.3%	70.2%	0.00	(50.76)	1.90	1.96	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.76	2.91	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	331.78	8.45	323.33	
			e					2.60	2.75	2.98	3.23	3.50	3.77	4.01	4.26	4.52	4.80	5.09	5.38	5.69	6.02	6.37	6.74	7.13	7.64	7.97	8.43	8.92	9.44	9.98	10.56	11.17	11.82	12.50	13.22	13.99	14.80		15.65		16.55
9	Cleco	3	CNL	9.8%	64.6%	0.00	(49.41)	1.43	1.58	1.71	1.85	2.00	2.15	2.36	2.58	2.82	3.08	3.38	3.55	3.78	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	222.58	10.33	312.24	
			e					2.60	2.76	2.98	3.23	3.50	3.77	4.00	4.25	4.50	4.77	5.05	5.34	5.65	5.98	6.32	6.69	7.07	7.48	7.91	8.37	8.86	9.37	9.91	10.48	11.09	11.73	12.41	13.12	13.88	14.68		15.53		16.43
13	DTE	4	DTE	9.2%	61.2%	0.00	(70.64)	2.59	2.73	2.88	3.00	3.15	3.30	3.48	3.68	3.88	4.09	4.31	4.56	4.83	5.11	5.40	5.71	6.04	6.39	6.76	7.15	7.57	8.00	8.47	8.96	9.47	10.02	10.60	11.21	11.86	12.55	402.13	13.27	388.86	
			e					4.05	4.25	4.49	4.74	5.00	5.26	5.55	5.86	6.17	6.51	6.85	7.25	7.67	8.11	8.59	9.07	9.60	10.15	10.74	11.36	12.02	12.71	13.45	14.22	15.04	15.91	16.83	17.81	18.84	19.92		21.08		22.29
15	Edison Int'l	5	EIX	8.4%	59.3%	0.00	(51.61)	1.35	1.45	1.59	1.74	1.90	2.06	2.23	2.41	2.59	2.79	3.01	3.18	3.36	3.56	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.58	5.90	6.24	6.60	6.98	7.39	7.81	8.26	8.74	237.91	9.25	228.67	
			e					3.65	3.70	3.87	4.06	4.25	4.44	4.64	4.68	4.75	4.86	4.97	5.26	5.56	5.88	6.22	6.58	6.96	7.36	7.79	8.24	8.72	9.22	9.75	10.32	10.91	11.54	12.21	12.92	13.66	14.45		15.29		16.17
23	IDACORP	6	IDA	8.6%	46.3%	0.00	(54.61)	1.57	1.76	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.76	3.98	4.21	4.46	4.71	4.98	5.27	5.67	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	207.80	11.57	196.23	
			e					3.50	3.45	3.50	3.55	3.60	3.65	3.69	3.74	3.78	3.82	3.86	4.09	4.32	4.57	4.64	5.12	5.41	5.73	6.06	6.41	6.78	7.17	7.59	8.02	8.49	8.96	9.50	10.05	10.63	11.24		11.89		12.58
34	PG&E	8	PCG	9.7%	68.6%	0.00	(43.65)	1.82	1.82	1.91	2.00	2.10	2.20	2.26	2.33	2.40	2.48	2.55	2.70	2.85	3.02	3.19	3.38	3.57	3.78	4.00	4.23	4.47	4.73	5.01	5.29	5.60	5.92	6.27	6.63	7.01	7.42	309.76	7.85	301.91	
			e					2.00	2.40	2.59	2.78	3.00	3.22	3.40	3.60	3.81	4.02	4.25	4.50	4.76	5.03	5.32	5.63	5.96	6.30	6.66	7.05	7.46	7.89	8.34	8.83	9.34	9.88	10.45	11.05	11.69	12.36		13.08		13.83
47	Westar	10	WR	9.0%	65.5%	0.00	(34.09)	1.35	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	196.71	5.60	191.10	
			e					2.25	2.35	2.48	2.61	2.75	2.89	3.07	3.26	3.45	3.66	3.88	4.10	4.34	4.59	4.85	5.13	5.43	5.74	6.08	6.43	6.80	7.19	7.61	8.05	8.51	9.00	9.52	10.08	10.66	11.27		11.93		12.61
				9.2%	62.3%	0.00																																			

BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV$_{TV}$	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity	
								Initial Stage						Transition Stage					Final Stage																						
1	AEP	1	AEP	9.5%	60.6%	0.00	(49.26)	2.02	2.11	2.20	2.30	2.40	2.50	2.60	2.71	2.82	2.93	3.10	3.28	3.47	3.67	3.88	4.11	4.34	4.59	4.86	5.14	5.44	5.75	6.08	6.44	6.81	7.20	7.62	8.06	8.52	9.02	297.31	9.54	287.77	
			e					3.10	3.30	3.62	3.76	4.00	4.25	4.49	4.74	5.00	5.28	5.58	5.89	6.23	6.59	6.97	7.37	7.90	8.25	8.72	9.23	9.75	10.33	10.92	11.55	12.22	12.93	13.67	14.47	15.30	16.19		17.12		18.11
2	Allete	2	ALE	9.4%	67.8%	0.00	(50.76)	1.96	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.75	2.91	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	8.45	332.27	8.94	323.93	
			e					2.60	2.75	2.98	3.23	3.50	3.77	4.01	4.26	4.52	4.80	5.09	5.38	5.69	6.02	6.37	6.74	7.13	7.54	7.97	8.43	8.92	9.44	9.98	10.56	11.17	11.82	12.50	13.22	13.99	14.80		15.65		16.55
9	Cleco	3	CNL	9.8%	61.2%	0.00	(49.41)	1.58	1.71	1.85	2.00	2.15	2.36	2.58	2.82	3.08	3.38	3.55	3.78	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.69	6.97	7.38	7.80	8.25	8.73	9.24	9.77	10.33	323.18	10.93	312.24	
			e					2.60	2.76	2.98	3.23	3.50	3.77	4.00	4.25	4.60	4.77	5.05	5.34	5.65	5.98	6.32	6.69	7.07	7.49	7.91	8.37	8.86	9.37	9.91	10.48	11.09	11.73	12.41	13.12	13.88	14.68		15.53		16.43
13	DTE	4	DTE	9.4%	58.5%	0.00	(70.64)	2.73	2.86	3.00	3.15	3.30	3.48	3.68	3.88	4.09	4.31	4.56	4.83	5.11	5.40	5.71	6.04	6.39	6.76	7.15	7.57	8.00	8.47	8.96	9.47	10.02	10.60	11.21	11.86	12.55	13.27	402.90	14.04	388.86	
			e					4.05	4.25	4.49	4.74	5.00	5.26	5.55	5.86	6.17	6.51	6.85	7.25	7.67	8.11	8.58	9.07	9.60	10.15	10.74	11.36	12.02	12.71	13.45	14.22	15.04	15.91	16.83	17.81	18.84	19.92		21.08		22.29
15	Edison Int'l	5	EIX	8.7%	56.3%	0.00	(51.61)	1.45	1.59	1.74	1.90	2.06	2.23	2.41	2.59	2.79	3.01	3.18	3.36	3.56	3.76	3.98	4.21	4.46	4.71	4.98	5.27	5.58	5.90	6.24	6.60	6.98	7.39	7.81	8.26	8.74	9.25	238.45	9.78	228.67	
			e					3.65	3.70	3.87	4.06	4.25	4.44	4.54	4.65	4.75	4.86	4.97	5.26	5.56	5.88	6.22	6.58	6.96	7.36	7.79	8.24	8.72	9.22	9.76	10.32	10.91	11.54	12.21	12.92	13.66	14.45		15.29		16.17
23	IDACORP	6	IDA	8.5%	43.4%	0.00	(54.61)	1.76	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	11.57	208.47	12.24	196.23	
			e					3.50	3.45	3.50	3.55	3.60	3.65	3.69	3.74	3.78	3.82	3.86	4.09	4.32	4.57	4.84	5.12	5.41	5.73	6.06	6.41	6.78	7.17	7.59	8.02	8.49	8.98	9.50	10.05	10.63	11.24		11.89		12.58
34	PG&E	8	PCG	9.9%	65.2%	0.00	(43.65)	1.82	1.91	2.00	2.10	2.20	2.26	2.33	2.40	2.48	2.55	2.70	2.85	3.02	3.19	3.38	3.57	3.78	4.00	4.23	4.47	4.73	5.01	5.29	5.60	5.92	6.27	6.63	7.01	7.42	7.85	316.21	8.30	301.91	
			e					2.00	2.40	2.59	2.78	3.00	3.22	3.40	3.60	3.81	4.02	4.25	4.50	4.76	5.03	5.32	5.63	5.96	6.30	6.66	7.05	7.46	7.89	8.34	8.83	9.34	9.88	10.45	11.05	11.69	12.36		13.08		13.83
47	Westar	10	WR	9.2%	63.3%	0.00	(34.09)	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	5.60	197.03	5.92	191.10	
			e					2.25	2.35	2.48	2.61	2.75	2.89	3.07	3.26	3.45	3.66	3.88	4.10	4.34	4.59	4.85	5.13	5.43	5.74	6.08	6.43	6.80	7.19	7.61	8.05	8.51	9.00	9.52	10.08	10.66	11.27		11.93		12.61
				9.3%	59.8%	0.00																																			

Average IRR of BOY & EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV$_{TV}$	Average 2013 – 2018 Dividend Growth Rates: EOY	BOY	Average
1	AEP	1	AEP	9.4%	61.7%	4.4%	4.3%	4.3%
2	Allete	2	ALE	9.3%	69.0%	3.8%	3.9%	3.9%
9	Cleco	3	CNL	9.7%	62.9%	8.0%	8.4%	8.2%
13	DTE	4	DTE	9.3%	59.8%	4.8%	5.0%	4.9%
15	Edison Int'l	5	EIX	8.5%	57.8%	9.2%	8.9%	9.1%
23	IDACORP	6	IDA	8.6%	44.9%	7.6%	8.2%	7.9%
34	PG&E	8	PCG	9.8%	67.4%	4.8%	4.4%	4.6%
47	Westar	10	WR	9.1%	64.4%	2.8%	2.9%	2.9%
	Group Average			9.2%	61.0%			

Staff Model X – Dividend Growth with Terminal Value as Perpetuity Sensitivity with TECO in Staff Peer Screen

5.78% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

Staff Sensitivity S1 with Addition of TECO **Model X**

BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{Div}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018
								Initial Stage					
1	AEP	1	AEP	9.2%	60.2%	0.00	(49.28)	1.95	2.02	2.11	2.20	2.30	2.40
2	Allete	2	ALE	8.9%	64.3%	0.00	(50.78)	1.90	1.96	2.04	2.12	2.20	2.28
9	Cleco	3	CNL	8.4%	61.5%	0.00	(49.41)	1.43	1.58	1.71	1.85	2.00	2.15
13	DTE	4	DTE	9.2%	61.0%	0.00	(70.64)	2.59	2.73	2.88	3.00	3.15	3.30
15	Edison Int'l	5	EIX	8.9%	67.7%	0.00	(51.61)	1.36	1.45	1.59	1.74	1.90	2.08
23	IDACORP	6	IDA	9.4%	61.2%	0.00	(54.61)	1.67	1.78	1.90	2.04	2.20	2.38
34	PG&E	7	PCG	9.2%	58.8%	0.00	(43.65)	1.82	1.82	1.91	2.00	2.10	2.20
43	TECO	8	TE	8.6%	51.9%	0.00	(18.64)	0.89	0.88	0.90	0.93	0.95	0.97
47	Westar	9	WR	8.9%	63.6%	0.00	(34.09)	1.35	1.40	1.44	1.48	1.52	1.56
				9.2%	61.2%	0.00							

Ticker	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Transition Stage					Final Stage									
AEP	2.50	2.60	2.71	2.82	2.93	3.10	3.28	3.47	3.67	3.88	4.11	4.34	4.59	4.86	5.14
ALE	2.37	2.46	2.56	2.65	2.75	2.91	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.55	4.82
CNL	2.36	2.58	2.82	3.08	3.36	3.55	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89
DTE	3.48	3.68	3.88	4.09	4.31	4.56	4.83	5.11	5.40	5.71	6.04	6.39	6.76	7.15	7.57
EIX	2.23	2.41	2.59	2.79	3.01	3.18	3.36	3.56	3.76	3.98	4.21	4.45	4.71	4.98	5.27
IDA	2.60	2.88	3.13	3.44	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59
PCG	2.28	2.33	2.40	2.48	2.65	2.70	2.85	3.02	3.19	3.38	3.57	3.78	4.00	4.23	4.47
TE	0.99	1.01	1.03	1.05	1.07	1.13	1.19	1.26	1.34	1.41	1.50	1.58	1.67	1.77	1.87
WR	1.61	1.66	1.71	1.77	1.82	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20

Ticker	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity
	Final Stage											
AEP	5.44	5.75	6.08	6.44	6.81	7.20	7.62	8.06	8.52	273.45	9.02	264.43
ALE	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.56	7.99	280.51	8.45	272.06
CNL	6.23	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	295.04	10.33	284.71
DTE	8.00	8.47	8.96	9.47	10.02	10.60	11.21	11.86	12.55	399.63	13.27	386.35
EIX	5.58	5.90	6.24	6.60	6.98	7.39	7.81	8.26	8.74	302.89	9.25	293.64
IDA	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	327.27	11.57	315.70
PCG	4.73	5.01	5.29	5.60	5.92	6.27	6.63	7.01	7.42	239.38	7.85	231.53
TE	1.98	2.10	2.22	2.35	2.48	2.62	2.78	2.94	3.11	88.43	3.29	85.15
WR	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	186.05	5.60	180.45

BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{Div}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018
								Initial Stage					
1	AEP	1	AEP	9.4%	57.8%	0.00	(49.28)	2.02	2.11	2.20	2.30	2.40	2.50
2	Allete	2	ALE	8.1%	82.1%	0.00	(50.78)	1.96	2.04	2.12	2.20	2.28	2.37
9	Cleco	3	CNL	8.6%	57.9%	0.00	(49.41)	1.68	1.71	1.85	2.00	2.15	2.36
13	DTE	4	DTE	9.4%	68.3%	0.00	(70.64)	2.73	2.88	3.00	3.15	3.30	3.48
15	Edison Int'l	5	EIX	9.1%	64.3%	0.00	(51.61)	1.45	1.59	1.74	1.90	2.08	2.23
23	IDACORP	6	IDA	9.7%	57.6%	0.00	(54.61)	1.76	1.90	2.04	2.20	2.38	2.60
34	PG&E	7	PCG	9.3%	57.6%	0.00	(43.65)	1.82	1.91	2.00	2.10	2.20	2.28
43	TECO	8	TE	9.6%	50.2%	0.00	(18.64)	0.88	0.90	0.93	0.95	0.97	0.99
47	Westar	9	WR	9.0%	61.6%	0.00	(34.09)	1.40	1.44	1.48	1.52	1.56	1.61
				9.4%	68.6%	0.00							

Ticker	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	Transition Stage					Final Stage									
AEP	2.60	2.71	2.82	2.93	3.10	3.28	3.47	3.67	3.88	4.11	4.34	4.59	4.86	5.14	5.44
ALE	2.46	2.55	2.65	2.75	2.81	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.55	4.82	6.10
CNL	2.58	2.82	3.08	3.38	3.55	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23
DTE	3.68	3.88	4.09	4.31	4.56	4.83	5.11	5.40	5.71	6.04	6.39	6.76	7.15	7.57	8.00
EIX	2.41	2.59	2.79	3.01	3.18	3.38	3.58	3.78	3.98	4.21	4.45	4.71	4.98	5.27	6.68
IDA	2.88	3.13	3.44	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98
PCG	2.33	2.40	2.48	2.56	2.70	2.85	3.02	3.19	3.38	3.57	3.78	4.00	4.23	4.47	4.73
TE	1.01	1.03	1.05	1.07	1.13	1.19	1.26	1.34	1.41	1.50	1.58	1.67	1.77	1.87	1.99
WR	1.66	1.71	1.77	1.82	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38

Ticker	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity
	Final Stage											
AEP	5.75	6.08	6.44	6.81	7.20	7.62	8.06	8.52	9.02	274.62	9.54	265.08
ALE	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	8.45	281.86	8.94	272.82
CNL	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	10.33	293.71	10.93	282.78
DTE	8.47	8.96	9.47	10.02	10.60	11.21	11.86	12.55	13.27	400.44	14.04	386.39
EIX	5.90	6.24	6.60	6.98	7.39	7.81	8.26	8.74	9.25	301.80	9.78	292.02
IDA	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	11.57	325.72	12.24	313.48
PCG	5.01	5.29	5.60	5.92	6.27	6.63	7.01	7.42	7.85	240.63	8.30	232.53
TE	2.10	2.22	2.35	2.48	2.62	2.78	2.94	3.11	3.29	89.48	3.48	85.98
WR	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	5.60	187.26	5.93	181.33

Average IRR of BOY & EOY Cash Flows					Terminal Value as % of NPV_{Div}	Average 2013 - 2018 Dividend Growth Rates		
Screen	Staff's Peer Utilities	Set	Ticker	IRR		EOY	BOY	Average
1	AEP	1	AEP	9.3%	59.0%	4.4%	4.3%	4.3%
2	Allete	2	ALE	9.0%	63.2%	3.8%	3.9%	3.9%
9	Cleco	3	CNL	9.5%	59.7%	8.0%	8.4%	8.2%
13	DTE	4	DTE	9.3%	59.6%	4.8%	5.0%	4.9%
15	Edison Int'l	5	EIX	9.0%	66.0%	9.2%	8.9%	9.1%
23	IDACORP	6	IDA	9.6%	59.4%	7.6%	8.2%	7.9%
34	PG&E	7	PCG	9.3%	58.7%	4.8%	4.4%	4.6%
43	TECO	8	TE	9.7%	61.1%	2.6%	2.4%	2.5%
47	Westar	9	WR	9.0%	62.6%	2.8%	2.9%	2.8%
	Group Average			9.29%	59.9%			

Staff Model Y – EPS Growth to Determine a Sale Terminal Value Sensitivity with TECO in Staff Peer Screen

[illegible] Annual Growth Rate - Stage 3 | Staff | EPS Growth to Determine a Sale Terminal Value Sensitivity S1 with Addition of TECO | Model Y | EPS Growth

EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{TV}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
								Initial Stage						Transition Stage				
1	AEP	1	AEP	9.4%	62.6%	(0.00)	(49.26)	1.95	2.02	2.11	2.20	2.30	2.40	2.50	2.60	2.71	2.82	2.93
			e					3.10	3.30	3.52	3.75	4.00	4.25	4.49	4.74	5.00	5.28	5.56
2	Allete	2	ALE	9.3%	70.2%	0.00	(50.78)	1.90	1.96	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.75
			e					2.60	2.75	2.98	3.23	3.50	3.77	4.01	4.26	4.52	4.80	5.09
9	Cleco	3	CNL	9.6%	64.6%	0.00	(49.41)	1.43	1.58	1.71	1.85	2.00	2.15	2.36	2.58	2.82	3.08	3.36
			e					2.60	2.75	2.98	3.23	3.50	3.77	4.00	4.25	4.50	4.77	5.05
13	DTE	4	DTE	9.2%	61.2%	0.00	(70.64)	2.59	2.73	2.86	3.00	3.15	3.30	3.48	3.68	3.88	4.09	4.31
			e					4.05	4.25	4.49	4.74	5.00	5.26	5.55	5.86	6.17	6.51	6.85
15	Edison Int'l	5	EIX	8.4%	59.3%	0.00	(51.61)	1.35	1.45	1.59	1.74	1.90	2.06	2.23	2.41	2.59	2.79	3.01
			e					3.65	3.70	3.87	4.06	4.25	4.44	4.64	4.65	4.76	4.86	4.97
23	IDACORP	6	IDA	8.6%	46.3%	0.00	(54.61)	1.67	1.78	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.76
			e					3.50	3.45	3.60	3.55	3.60	3.65	3.69	3.74	3.78	3.82	3.86
34	PG&E	7	PCG	9.7%	63.6%	0.00	(43.65)	1.82	1.82	1.91	2.00	2.10	2.20	2.26	2.33	2.40	2.48	2.55
			e					2.00	2.40	2.59	2.78	3.00	3.22	3.40	3.60	3.81	4.02	4.25
43	TECO	8	TE	9.6%	51.9%	0.00	(16.64)	0.80	0.88	0.90	0.93	0.95	0.97	0.99	1.01	1.03	1.05	1.07
			e					2.25	2.35	2.48	2.61	2.75	2.89	3.01	3.14	3.27	3.40	3.54
47	Westar	9	WR	9.0%	65.6%	0.00	(34.09)	1.35	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82
			e					2.25	2.35	2.48	2.61	2.75	2.89	3.07	3.26	3.45	3.66	3.88
				9.2%	61.2%	0.00												

Staff's Peer Utilities	Ticker	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Sale	2043
		Final Stage																						
AEP	AEP	3.10	3.28	3.47	3.67	3.88	4.11	4.34	4.59	4.86	5.14	5.44	5.75	6.08	6.44	6.81	7.20	7.62	8.06	8.52	296.78	9.02	287.77	
	e	5.89	6.23	6.59	6.97	7.37	7.80	8.25	8.72	9.23	9.76	10.33	10.92	11.55	12.22	12.93	13.67	14.47	15.30	16.19		17.12		18.11
Allete	ALE	2.91	3.07	3.26	3.44	3.64	3.85	4.07	4.31	4.56	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	331.78	8.45	323.33	
	e	5.38	5.69	6.02	6.37	6.74	7.13	7.54	7.97	8.43	8.92	9.44	9.99	10.56	11.17	11.82	12.50	13.22	13.99	14.80		15.65		16.55
Cleco	CNL	3.55	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.26	8.73	9.24	9.77	322.58	10.33	312.24	
	e	5.34	5.65	5.98	6.32	6.69	7.07	7.48	7.91	8.37	8.86	9.37	9.91	10.48	11.09	11.73	12.41	13.13	13.88	14.68		15.53		16.43
DTE	DTE	4.56	4.83	5.11	5.40	5.71	6.04	6.39	6.76	7.15	7.57	8.00	8.47	8.96	9.47	10.02	10.60	11.21	11.86	12.55	402.13	13.27	388.86	
	e	7.25	7.67	8.11	8.58	9.07	9.60	10.15	10.74	11.36	12.02	12.71	13.45	14.22	15.04	15.91	16.83	17.81	18.84	19.92		21.08		22.29
Edison Int'l	EIX	3.18	3.36	3.56	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.58	5.90	6.24	6.60	6.98	7.39	7.81	8.26	8.74	237.91	9.25	228.67	
	e	5.26	5.56	5.88	6.22	6.58	6.96	7.36	7.79	8.24	8.72	9.22	9.75	10.32	10.91	11.54	12.21	12.92	13.66	14.45		15.29		16.17
IDACORP	IDA	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	207.80	11.57	196.23	
	e	4.09	4.32	4.57	4.84	5.12	5.41	5.73	6.06	6.41	6.78	7.17	7.58	8.02	8.49	8.98	9.50	10.05	10.63	11.24		11.89		12.58
PG&E	PCG	2.70	2.85	3.02	3.19	3.38	3.57	3.78	4.00	4.23	4.47	4.73	5.01	5.29	5.60	5.92	6.27	6.63	7.01	7.42	309.76	7.85	301.91	
	e	4.50	4.76	5.03	5.32	5.63	5.96	6.30	6.66	7.05	7.46	7.89	8.34	8.83	9.34	9.88	10.45	11.05	11.69	12.36		13.08		13.83
TECO	TE	1.13	1.19	1.26	1.34	1.41	1.50	1.58	1.67	1.77	1.87	1.98	2.10	2.22	2.35	2.48	2.62	2.78	2.94	3.11	88.42	3.29	85.13	
	e	3.74	3.96	4.19	4.43	4.69	4.96	5.24	5.55	5.87	6.21	6.56	6.94	7.34	7.77	8.22	8.69	9.20	9.73	10.29		10.88		11.51
Westar	WR	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	196.71	5.60	191.10	
	e	4.10	4.34	4.59	4.85	5.13	5.43	5.74	6.08	6.43	6.80	7.19	7.61	8.05	8.51	9.00	9.52	10.08	10.66	11.27		11.93		12.61

BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{TV}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
								Initial Stage						Transition Stage				
1	AEP	1	AEP	9.6%	60.5%	0.00	(49.26)	2.02	2.11	2.20	2.30	2.40	2.50	2.60	2.71	2.82	2.93	3.10
			e					3.10	3.30	3.52	3.75	4.00	4.25	4.49	4.74	5.00	5.28	5.56
2	Allete	2	ALE	9.4%	67.8%	0.00	(50.78)	1.98	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.75	2.91
			e					2.60	2.75	2.98	3.23	3.50	3.77	4.01	4.26	4.52	4.80	5.09
9	Cleco	3	CNL	9.8%	61.2%	0.00	(49.41)	1.58	1.71	1.85	2.00	2.15	2.36	2.58	2.82	3.08	3.36	3.55
			e					2.60	2.75	2.98	3.23	3.50	3.77	4.00	4.25	4.50	4.77	5.05
13	DTE	4	DTE	9.4%	58.5%	0.00	(70.64)	2.73	2.88	3.00	3.15	3.30	3.48	3.68	3.88	4.09	4.31	4.56
			e					4.05	4.25	4.49	4.74	5.00	5.26	5.55	5.86	6.17	6.51	6.85
15	Edison Int'l	5	EIX	8.7%	56.3%	0.00	(51.61)	1.45	1.59	1.74	1.90	2.06	2.23	2.41	2.59	2.79	3.01	3.18
			e					3.65	3.70	3.87	4.06	4.25	4.44	4.54	4.65	4.75	4.86	4.97
23	IDACORP	6	IDA	8.9%	43.4%	0.00	(54.61)	1.76	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.76	3.98
			e					3.50	3.45	3.50	3.55	3.60	3.65	3.69	3.74	3.78	3.82	3.86
34	PG&E	7	PCG	9.9%	68.2%	0.00	(43.65)	1.82	1.91	2.00	2.10	2.20	2.26	2.33	2.40	2.48	2.55	2.70
			e					2.00	2.40	2.59	2.78	3.00	3.22	3.40	3.60	3.81	4.02	4.25
43	TECO	8	TE	9.8%	60.0%	0.00	(16.64)	0.88	0.90	0.93	0.95	0.97	0.99	1.01	1.03	1.05	1.07	1.13
			e					2.25	2.35	2.48	2.61	2.75	2.89	3.01	3.14	3.27	3.40	3.54
47	Westar	9	WR	9.2%	63.3%	0.00	(34.09)	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82	1.93
			e					2.25	2.35	2.48	2.61	2.75	2.89	3.07	3.26	3.45	3.66	3.88
				9.4%	58.6%	0.00												

Staff's Peer Utilities	Ticker	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity	
		Final Stage																						
AEP	AEP	3.28	3.47	3.67	3.88	4.11	4.34	4.59	4.86	5.14	5.44	5.75	6.08	6.44	6.81	7.20	7.62	8.06	8.52	9.02	297.31	9.54	287.77	
	e	5.89	6.23	6.59	6.97	7.37	7.80	8.25	8.72	9.23	9.76	10.33	10.92	11.55	12.22	12.93	13.67	14.47	15.30	16.19		17.12		18.11
Allete	ALE	3.07	3.29	3.44	3.64	3.85	4.07	4.31	4.56	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	8.45	332.27	8.94	323.33	
	e	5.38	5.69	6.02	6.37	6.74	7.13	7.54	7.97	8.43	8.92	9.44	9.99	10.56	11.17	11.82	12.50	13.22	13.99	14.80		15.65		16.55
Cleco	CNL	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.26	8.73	9.24	9.77	10.33	323.18	10.93	312.24	
	e	5.34	5.65	5.98	6.32	6.69	7.07	7.48	7.91	8.37	8.86	9.37	9.91	10.48	11.09	11.73	12.41	13.12	13.88	14.68		15.53		16.43
DTE	DTE	4.83	5.11	5.40	5.71	6.04	6.39	6.76	7.15	7.57	8.00	8.47	8.96	9.47	10.02	10.60	11.21	11.86	12.55	13.27	402.90	14.04	388.86	
	e	7.25	7.67	8.11	8.58	9.07	9.60	10.15	10.74	11.36	12.02	12.71	13.45	14.22	15.04	15.91	16.83	17.81	18.84	19.92		21.08		22.29
Edison Int'l	EIX	3.36	3.56	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.58	5.90	6.24	6.60	6.98	7.39	7.81	8.26	8.74	9.25	238.45	9.78	228.67	
	e	5.26	5.56	5.88	6.22	6.58	6.96	7.36	7.79	8.24	8.72	9.22	9.75	10.32	10.91	11.54	12.21	12.92	13.66	14.45		15.29		16.17
IDACORP	IDA	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	11.57	208.47	12.24	196.23	
	e	4.09	4.32	4.57	4.84	5.12	5.41	5.73	6.06	6.41	6.78	7.17	7.59	8.02	8.49	8.98	9.50	10.05	10.63	11.24		11.89		12.58
PG&E	PCG	2.85	3.02	3.19	3.38	3.57	3.78	4.00	4.23	4.47	4.73	5.01	5.29	5.60	5.92	6.27	6.63	7.01	7.42	7.85	310.21	8.30	301.91	
	e	4.50	4.76	5.03	5.32	5.63	5.96	6.30	6.66	7.05	7.46	7.89	8.34	8.83	9.34	9.88	10.45	11.05	11.69	12.36		13.08		13.83
TECO	TE	1.19	1.26	1.34	1.41	1.50	1.58	1.67	1.77	1.87	1.98	2.10	2.22	2.35	2.48	2.62	2.78	2.94	3.11	3.29	88.61	3.48	86.13	
	e	3.74	3.96	4.19	4.43	4.69	4.96	5.24	5.55	5.87	6.21	6.56	6.94	7.34	7.77	8.22	8.69	9.20	9.73	10.29		10.88		11.51
Westar	WR	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	5.60	197.03	5.93	191.10	
	e	4.10	4.34	4.59	4.85	5.13	5.43	5.74	6.08	6.43	6.80	7.19	7.61	8.05	8.51	9.00	9.52	10.08	10.66	11.27		11.93		12.61

Average IRR of BOY & EOY Cash Flows					Terminal Value as % of NPV_{TV}	Average 2013 - 2018 Dividend Growth Rates		
Screen	Staff's Peer Utilities	Set	Ticker	IRR		EOY	BOY	Average
1	AEP	1	AEP	9.4%	61.7%	4.4%	4.3%	4.3%
2	Allete	2	ALE	9.3%	69.0%	3.9%	3.9%	3.9%
9	Cleco	3	CNL	9.7%	62.9%	8.0%	8.4%	8.2%
13	DTE	4	DTE	9.3%	59.8%	4.8%	5.0%	4.9%
15	Edison Int'l	5	EIX	8.6%	57.8%	9.2%	8.9%	9.1%
23	IDACORP	6	IDA	8.8%	44.9%	7.6%	8.2%	7.9%
34	PG&E	7	PCG	9.8%	67.4%	4.8%	4.4%	4.6%
43	TECO	8	TE	9.7%	50.9%	2.6%	2.4%	2.5%
47	Westar	9	WR	9.1%	64.4%	2.8%	2.9%	2.8%
	Group Average			9.30%	59.9%			

Staff Model X – Dividend Growth with Terminal Value as Perpetuity
MidCap Sensitivity

5.78% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

Staff Sensitivity S2 Mid-Cap Utilities Only **Model X**

EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
								Initial Stage						Transition Stage				
2	Allete	1	ALE	8.9%	64.3%	0.00	(50.78)	1.90	1.96	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.75
9	Cleco	2	CNL	9.4%	61.5%	0.00	(49.41)	1.43	1.58	1.71	1.85	2.00	2.15	2.36	2.58	2.82	3.08	3.36
23	IDACORP	3	IDA	9.4%	61.2%	0.00	(54.61)	1.57	1.76	1.90	2.04	2.20	2.38	2.60	2.86	3.13	3.44	3.76
47	Westar	4	WR	8.9%	63.6%	0.00	(34.09)	1.35	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82
				9.2%	62.5%	0.00												

Screen	Staff's Peer Utilities	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity
		Final Stage																					
2	Allete	2.91	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	280.61	8.45	272.06
9	Cleco	3.56	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.58	6.97	7.38	7.80	8.25	8.73	9.24	9.77	295.04	10.33	284.71
23	IDACORP	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	327.27	11.57	315.70
47	Westar	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	186.05	6.60	180.45

BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DIV}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
								Initial Stage						Transition Stage				
2	Allete	1	ALE	9.1%	62.1%	0.00	(50.78)	1.96	2.04	2.12	2.20	2.29	2.37	2.46	2.56	2.65	2.75	2.91
9	Cleco	2	CNL	9.6%	57.9%	0.00	(49.41)	1.58	1.71	1.86	2.00	2.15	2.36	2.58	2.82	3.08	3.36	3.65
23	IDACORP	3	IDA	9.7%	57.6%	0.00	(54.61)	1.76	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.76	3.98
47	Westar	4	WR	9.0%	61.6%	0.00	(34.09)	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82	1.93
				9.4%	59.8%	0.00												

Screen	Staff's Peer Utilities	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity
		Final Stage																					
2	Allete	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	8.45	281.66	8.94	272.92
9	Cleco	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	10.33	293.71	10.93	282.78
23	IDACORP	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	11.57	325.72	12.24	313.48
47	Westar	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	5.60	187.26	6.93	181.33

Average IRR of BOY & EOY Cash Flows					Terminal Value as	Average 2013 - 2018 Dividend Growth Rates		
Screen	Staff's Peer Utilities	Set	Ticker	IRR	% of NPV_{DIV}	EOY	BOY	Average
2	Allete	1	ALE	9.0%	63.2%	3.9%	3.9%	3.9%
9	Cleco	2	CNL	9.5%	59.7%	8.0%	8.4%	8.2%
23	IDACORP	3	IDA	9.0%	59.4%	7.6%	8.2%	7.9%
47	Westar	4	WR	9.0%	62.6%	2.8%	2.9%	2.8%
	Group Average			9.26%	61.2%			

Staff Model Y – EPS Growth to Determine a Sale Terminal Value
MidCap Sensitivity

5.74% Annual Growth Rate - Stage 3

Staff EPS Growth to Determine a Sale Terminal Value
Sensitivity S2 Mid-Cap Utilities Only

EPS Growth
Model Y

EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV$_{TV}$	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
								Initial Stage						Transition Stage				
2	Allete	1	ALE	9.3%	70.2%	0.00	(50.78)	1.90	1.96	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.75
			e					2.60	2.75	2.98	3.23	3.50	3.77	4.01	4.26	4.52	4.80	5.09
9	Cleco	2	CNL	9.6%	64.6%	0.00	(49.41)	1.43	1.58	1.71	1.85	2.00	2.15	2.38	2.58	2.82	3.08	3.36
			e					2.80	2.75	2.98	3.23	3.50	3.77	4.00	4.26	4.50	4.77	5.05
23	IDACORP	3	IDA	8.6%	46.3%	0.00	(54.61)	1.57	1.76	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.76
			e					3.50	3.45	3.50	3.55	3.60	3.65	3.69	3.74	3.78	3.82	3.86
47	Westar	4	WR	9.0%	65.5%	0.00	(34.09)	1.35	1.40	1.44	1.49	1.52	1.56	1.61	1.66	1.71	1.77	1.82
			e					2.25	2.35	2.48	2.61	2.76	2.89	3.07	3.26	3.45	3.66	3.88
				9.1%	61.6%	0.00												

Ticker	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Sale	2043
	Final Stage																						
ALE	2.91	3.07	3.26	3.44	3.64	3.85	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	331.78	8.45	322.33	
e	5.38	5.69	6.02	6.37	6.74	7.13	7.54	7.97	8.43	8.92	9.44	9.98	10.56	11.17	11.82	12.50	13.22	13.99	14.80		15.65		16.55
CNL	3.55	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	322.58	10.33	312.24	
e	5.34	5.65	5.98	6.32	6.69	7.07	7.48	7.91	8.37	8.86	9.37	9.91	10.48	11.09	11.73	12.41	13.12	13.88	14.68		15.53		16.43
IDA	3.90	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.90	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	207.90	11.67	196.22	
e	4.09	4.32	4.57	4.84	5.12	5.41	5.73	6.06	6.41	6.78	7.17	7.59	8.02	8.49	8.98	9.50	10.05	10.63	11.24		11.89		13.58
WR	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	196.71	5.60	191.10	
e	4.10	4.34	4.59	4.85	5.13	5.43	5.74	6.08	6.43	6.80	7.19	7.61	8.05	8.51	9.00	9.62	10.08	10.66	11.27		11.93		12.51

BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV$_{TV}$	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
								Initial Stage						Transition Stage				
2	Allete	1	ALE	9.4%	57.8%	0.00	(50.78)	1.96	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.75	2.91
			e					2.60	2.76	2.98	3.23	3.50	3.77	4.01	4.26	4.52	4.80	5.09
9	Cleco	2	CNL	9.8%	61.3%	0.00	(49.41)	1.58	1.71	1.85	2.00	2.15	2.36	2.58	2.82	3.08	3.36	3.55
			e					2.80	2.75	2.98	3.23	3.50	3.77	4.00	4.26	4.50	4.77	5.05
23	IDACORP	3	IDA	8.9%	43.4%	0.00	(54.61)	1.76	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.76	3.98
			e					3.50	3.46	3.50	3.55	3.60	3.65	3.69	3.74	3.78	3.82	3.86
47	Westar	4	WR	9.2%	63.3%	0.00	(34.09)	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82	1.93
			e					2.25	2.35	2.48	2.61	2.75	2.89	3.07	3.26	3.45	3.66	3.88
				9.3%	56.5%	0.00												

Ticker	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity	
	Final Stage																						
ALE	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.65	4.82	5.10	5.39	5.70	6.03	6.38	6.76	7.14	7.55	7.99	8.45	332.27	8.94	323.33	
e	5.38	5.69	6.02	6.37	6.74	7.13	7.54	7.07	8.43	8.92	9.44	9.98	10.56	11.17	11.82	12.50	13.22	13.99	14.80		15.65		16.65
CNL	3.76	3.98	4.21	4.46	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	10.33	323.16	10.93	312.24	
e	5.34	5.65	5.98	6.32	6.69	7.07	7.48	7.91	8.37	8.86	9.37	9.91	10.48	11.09	11.73	12.41	13.12	13.88	14.68		15.53		16.43
IDA	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	11.57	208.47	12.24	196.23	
e	4.09	4.32	4.57	4.84	5.12	5.41	5.73	6.06	6.41	6.78	7.17	7.59	8.02	8.49	8.98	9.50	10.05	10.63	11.24		11.89		12.58
WR	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	5.60	197.03	5.93	191.10	
e	4.10	4.34	4.59	4.85	5.13	5.43	5.74	6.08	6.43	6.80	7.19	7.61	8.05	8.61	9.00	9.62	10.08	10.68	11.27		11.93		12.61

Average IRR of BOY & EOY Cash Flows					Terminal Value as % of	Average 2013 - 2018 Dividend Growth Rates		
Screen	Staff's Peer Utilities	Set	Ticker	IRR	NPV$_{TV}$	EOY	BOY	Average
2	Allete	1	ALE	9.3%	59.0%	3.9%	3.9%	3.9%
9	Cleco	2	CNL	9.7%	62.9%	8.0%	8.4%	8.2%
23	IDACORP	3	IDA	8.8%	44.9%	7.6%	8.2%	7.9%
47	Westar	4	WR	9.1%	64.4%	2.8%	2.9%	2.8%
	Group Average			9.22%	60.3%			

Staff Model X – Dividend Growth with Terminal Value as Perpetuity Company's Proposed Peers

5.78% Annual Growth Rate - Stage 3

Dividend Growth with Terminal Value as Perpetuity

Staff **Staff Model X with Company Peers**

EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DV}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
								Initial Stage						Transition Stage				
2	Allete	1	ALE	8.9%	64.3%	0.00	(50.78)	1.90	1.98	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.75
3	Alliant	2	LNT	8.8%	66.4%	0.00	(53.57)	1.88	1.96	2.04	2.12	2.20	2.28	2.38	2.49	2.59	2.70	2.82
5	Avista	3	AVA	9.2%	59.5%	0.00	(29.48)	1.22	1.28	1.32	1.36	1.40	1.44	1.50	1.56	1.62	1.68	1.75
6	Black Hills	4	BKH	N/A	N/A	N/A	(55.91)	1.52	1.56	1.64	1.72	1.80	1.88	1.96	2.04	2.12	2.21	2.30
9	Cleco	5	CNL	9.4%	61.5%	0.00	(49.41)	1.43	1.58	1.71	1.85	2.00	2.15	2.36	2.58	2.82	3.08	3.36
10	CMS	6	CMS	8.6%	58.0%	0.00	(28.28)	1.02	1.08	1.15	1.22	1.30	1.38	1.47	1.56	1.66	1.80	1.92
21	Great Plains	7	GXP	9.0%	63.7%	0.00	(25.84)	0.88	0.94	0.99	1.04	1.10	1.16	1.22	1.28	1.35	1.42	1.49
22	Hawaiian	8	HE	8.1%	58.8%	0.00	(25.51)	1.24	1.24	1.26	1.28	1.30	1.32	1.33	1.35	1.36	1.37	1.39
23	IDACORP	9	IDA	9.4%	61.2%	0.00	(54.61)	1.67	1.78	1.90	2.04	2.20	2.36	2.60	2.88	3.13	3.44	3.76
26	MGE	10	MGEE	8.7%	66.6%	0.00	(44.83)	1.61	1.65	1.72	1.79	1.86	1.93	2.00	2.08	2.16	2.24	2.32
29	Northwestern	11	NEW	8.6%	68.9%	0.00	(45.88)	1.52	1.56	1.64	1.72	1.80	1.88	1.96	2.04	2.13	2.22	2.31
31	OGE	12	OGE	8.0%	67.5%	0.00	(35.38)	0.84	0.93	1.03	1.13	1.25	1.37	1.50	1.65	1.81	1.98	2.18
35	PGE	13	POR	8.6%	69.0%	0.00	(31.32)	1.09	1.12	1.16	1.21	1.25	1.29	1.34	1.38	1.43	1.47	1.52
36	Pinnacle	14	PNW	9.3%	59.0%	0.00	(54.35)	2.20	2.29	2.39	2.49	2.60	2.71	2.82	2.94	3.06	3.18	3.31
37	PNM	15	PNM	10.1%	55.6%	0.00	(25.91)	0.66	0.74	0.84	0.95	1.06	1.21	1.37	1.58	1.76	1.98	2.23
40	Scana	16	SCG	9.1%	60.7%	0.00	(48.84)	2.02	2.03	2.12	2.21	2.30	2.39	2.47	2.56	2.64	2.72	2.81
43	TECO	17	TE	9.6%	51.9%	0.00	(16.84)	0.88	0.88	0.90	0.93	0.95	0.97	0.99	1.01	1.03	1.05	1.07
45	UNS	18	UNS	8.8%	68.3%	0.00	(30.17)	1.74	1.78	1.92	2.09	2.28	2.47	2.62	2.78	2.95	3.12	3.31
47	Westar	19	WR	8.9%	63.6%	0.00	(34.09)	1.35	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82
48	Wisconsin	20	WEC	10.5%	49.9%	0.00	(42.76)	1.45	1.56	1.72	1.90	2.10	2.30	2.57	2.86	3.16	3.53	3.91
				9.2%	61.6%	0.00												

Staff's Peer Utilities	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity
	Final Stage																					
Allete	2.91	3.07	3.25	3.44	3.64	3.86	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	260.51	8.45	272.06
Alliant	2.98	3.15	3.34	3.53	3.73	3.95	4.18	4.42	4.67	4.94	5.23	5.53	5.85	6.19	6.55	6.93	7.33	7.76	8.20	297.89	8.67	289.21
Avista	1.85	1.96	2.07	2.19	2.32	2.45	2.59	2.74	2.90	3.07	3.25	3.44	3.63	3.84	4.07	4.30	4.55	4.81	5.09	162.42	5.39	157.04
Black Hills	2.43	2.57	2.72	2.87	3.04	3.22	3.40	3.60	3.81	4.03	4.26	4.51	4.77	5.04	5.33	5.64	5.97	6.31	6.68	#VALUE!	7.06	#VALUE!
Cleco	3.55	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	295.04	10.33	284.71
CMS	2.03	2.14	2.27	2.40	2.54	2.68	2.84	3.00	3.18	3.36	3.56	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	163.53	5.90	157.63
Great Plains	1.58	1.67	1.77	1.87	1.98	2.09	2.21	2.34	2.48	2.62	2.77	2.93	3.10	3.28	3.47	3.67	3.88	4.10	4.34	146.04	4.59	141.45
Hawaiian	1.47	1.55	1.64	1.74	1.84	1.94	2.06	2.18	2.30	2.43	2.57	2.72	2.88	3.05	3.22	3.41	3.61	3.82	4.04	134.24	4.27	129.97
IDACORP	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	327.27	11.57	315.70
MGE	2.45	2.60	2.75	2.90	3.07	3.25	3.44	3.64	3.85	4.07	4.30	4.55	4.82	5.09	5.39	5.70	6.03	6.38	6.75	247.81	7.14	240.67
Northwestern	2.44	2.58	2.73	2.89	3.05	3.23	3.42	3.61	3.82	4.04	4.28	4.53	4.79	5.06	5.36	5.67	5.99	6.34	6.71	255.63	7.09	248.53
OGE	2.29	2.42	2.56	2.71	2.87	3.03	3.21	3.39	3.59	3.80	4.02	4.25	4.49	4.75	5.03	5.32	5.63	5.95	6.30	211.87	6.66	205.21
PGE	1.61	1.70	1.80	1.91	2.02	2.13	2.25	2.38	2.52	2.67	2.82	2.99	3.16	3.34	3.53	3.74	3.96	4.18	4.43	172.28	4.68	167.60
Pinnacle	3.50	3.70	3.92	4.14	4.38	4.64	4.90	5.19	5.49	5.80	6.14	6.50	6.87	7.27	7.69	8.13	8.60	9.10	9.63	301.54	10.18	291.36
PNM	2.35	2.49	2.63	2.79	2.95	3.12	3.30	3.49	3.69	3.90	4.13	4.37	4.62	4.89	5.17	5.47	5.79	6.12	6.47	165.09	6.86	158.18
Scana	2.97	3.14	3.32	3.52	3.72	3.93	4.16	4.40	4.66	4.92	5.21	5.51	5.83	6.17	6.52	6.90	7.30	7.72	8.17	268.54	8.64	259.90
TECO	1.13	1.19	1.26	1.34	1.41	1.50	1.58	1.67	1.77	1.87	1.98	2.10	2.22	2.35	2.48	2.62	2.78	2.94	3.11	88.43	3.29	85.16
UNS	3.50	3.70	3.91	4.14	4.38	4.63	4.90	5.18	5.48	5.80	6.13	6.49	6.86	7.26	7.68	8.12	8.59	9.09	9.61	348.13	10.17	335.96
Westar	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	186.05	5.60	180.45
Wisconsin	4.14	4.38	4.63	4.90	5.18	5.48	5.80	6.13	6.49	6.86	7.26	7.68	8.12	8.59	9.09	9.62	10.17	10.76	11.38	267.39	12.04	255.34

BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DV}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
								Initial Stage						Transition Stage				
2	Allete	1	ALE	9.1%	62.1%	0.00	(50.78)	1.95	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.75	2.91
3	Alliant	2	LNT	8.9%	64.1%	0.00	(53.57)	1.96	2.04	2.12	2.20	2.28	2.38	2.49	2.59	2.70	2.82	2.98
5	Avista	3	AVA	9.4%	57.2%	(0.00)	(29.48)	1.28	1.32	1.36	1.40	1.44	1.50	1.56	1.62	1.68	1.75	1.85
6	Black Hills	4	BKH	8.2%	76.2%	0.00	(55.91)	1.56	1.64	1.72	1.80	1.88	1.96	2.04	2.12	2.21	2.30	2.43
9	Cleco	5	CNL	9.6%	57.8%	0.00	(49.41)	1.58	1.71	1.85	2.00	2.15	2.36	2.58	2.82	3.08	3.36	3.55
10	CMS	6	CMS	9.7%	55.0%	0.00	(28.28)	1.08	1.15	1.22	1.30	1.38	1.47	1.56	1.66	1.80	1.92	2.03
21	Great Plains	7	GXP	9.2%	61.0%	0.00	(25.84)	0.94	0.99	1.04	1.10	1.16	1.22	1.28	1.35	1.42	1.49	1.58
22	Hawaiian	8	HE	8.2%	57.4%	0.00	(25.51)	1.24	1.26	1.28	1.30	1.32	1.33	1.35	1.36	1.37	1.39	1.47
23	IDACORP	9	IDA	9.7%	57.6%	0.00	(54.61)	1.78	1.90	2.04	2.20	2.36	2.60	2.88	3.13	3.44	3.76	3.98
26	MGE	10	MGEE	8.9%	64.4%	0.00	(44.83)	1.65	1.72	1.79	1.86	1.93	2.00	2.08	2.16	2.24	2.32	2.45
29	Northwestern	11	NEW	8.8%	66.5%	0.00	(45.88)	1.56	1.64	1.72	1.80	1.88	1.96	2.04	2.13	2.22	2.31	2.44
31	OGE	12	OGE	8.2%	63.8%	0.00	(35.38)	0.93	1.03	1.13	1.25	1.37	1.50	1.65	1.81	1.98	2.18	2.29
35	PGE	13	POR	8.7%	66.9%	0.00	(31.32)	1.12	1.16	1.21	1.25	1.29	1.34	1.38	1.43	1.47	1.52	1.61
36	Pinnacle	14	PNW	9.5%	56.6%	0.00	(54.35)	2.29	2.39	2.49	2.60	2.71	2.82	2.94	3.06	3.18	3.31	3.50
37	PNM	15	PNM	10.4%	51.2%	0.00	(25.91)	0.74	0.84	0.95	1.06	1.21	1.37	1.58	1.76	1.98	2.23	2.35
40	Scana	16	SCG	9.3%	58.6%	0.00	(48.94)	2.03	2.12	2.21	2.30	2.39	2.47	2.56	2.64	2.72	2.81	2.97
43	TECO	17	TE	9.8%	50.2%	0.00	(16.84)	0.88	0.90	0.93	0.95	0.97	0.99	1.01	1.03	1.05	1.07	1.13
45	UNS	18	UNS	9.0%	65.3%	0.00	(30.17)	1.78	1.92	2.09	2.28	2.47	2.62	2.78	2.95	3.12	3.31	3.50
47	Westar	19	WR	9.0%	61.6%	0.00	(34.09)	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82	1.93
48	Wisconsin	20	WEC	10.8%	46.0%	0.00	(42.76)	1.56	1.72	1.90	2.10	2.30	2.57	2.86	3.16	3.53	3.91	4.14
				9.3%	60.0%	0.00												

Staff's Peer Utilities	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity
	Final Stage																					
Allete	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	8.45	281.88	8.94	272.92
Alliant	3.15	3.34	3.53	3.73	3.95	4.18	4.42	4.67	4.94	5.23	5.53	5.85	6.19	6.55	6.93	7.33	7.75	8.20	8.67	299.03	9.17	289.65
Avista	1.96	2.07	2.19	2.32	2.45	2.59	2.74	2.90	3.07	3.25	3.44	3.63	3.84	4.07	4.30	4.55	4.81	5.09	5.39	163.32	5.70	157.83
Black Hills	2.57	2.72	2.87	3.04	3.22	3.40	3.60	3.81	4.03	4.26	4.51	4.77	5.04	5.33	5.64	5.97	6.31	6.68	7.06	312.79	7.47	305.32
Cleco	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	10.33	293.71	10.93	282.78
CMS	2.14	2.27	2.40	2.54	2.68	2.84	3.00	3.18	3.36	3.56	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.90	163.47	6.24	157.23
Great Plains	1.67	1.77	1.87	1.98	2.09	2.21	2.34	2.48	2.62	2.77	2.93	3.10	3.28	3.47	3.67	3.88	4.10	4.34	4.59	146.23	4.86	141.37
Hawaiian	1.55	1.64	1.74	1.84	1.94	2.06	2.18	2.30	2.43	2.57	2.72	2.88	3.05	3.22	3.41	3.61	3.82	4.04	4.27	135.92	4.52	131.40
IDACORP	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	11.57	325.72	12.24	313.48
MGE	2.60	2.75	2.90	3.07	3.25	3.44	3.64	3.85	4.07	4.30	4.55	4.82	5.09	5.39	5.70	6.03	6.38	6.75	7.14	248.84	7.56	241.30
Northwestern	2.58	2.73	2.89	3.05	3.23	3.42	3.61	3.82	4.04	4.28	4.53	4.79	5.06	5.36	5.67	5.99	6.34	6.71	7.09	256.48	7.50	248.98
OGE	2.42	2.56	2.71	2.87	3.03	3.21	3.39	3.59	3.80	4.02	4.25	4.49	4.75	5.03	5.32	5.63	5.95	6.30	6.66	210.64	7.05	203.60
PGE	1.70	1.80	1.91	2.02	2.13	2.25	2.38	2.52	2.67	2.82	2.99	3.16	3.34	3.53	3.74	3.96	4.18	4.43	4.68	173.15	4.95	168.20
Pinnacle	3.70	3.92	4.14	4.38	4.64	4.90	5.19	5.49	5.80	6.14	6.50	6.87	7.27	7.69	8.13	8.60	9.10	9.63	10.18	302.88	10.77	292.09
PNM	2.49	2.63	2.79	2.95	3.12	3.30	3.49	3.69	3.90	4.13	4.37	4.62	4.89	5.17	5.47	5.79	6.12	6.47	6.85	163.36	7.24	156.11
Scana	3.14	3.32	3.52	3.72	3.93	4.16	4.40	4.66	4.92	5.21	5.51	5.83	6.17	6.52	6.90	7.30	7.72	8.17	8.64	270.22	9.14	261.08
TECO	1.19	1.26	1.34	1.41	1.50	1.58	1.67	1.77	1.87	1.98	2.10	2.22	2.35	2.48	2.62	2.78	2.94	3.11	3.29	89.46	3.48	85.98
UNS	3.70	3.91	4.14	4.38	4.63	4.90	5.18	5.48	5.80	6.13	6.49	6.86	7.26	7.68	8.12	8.59	9.09	9.61	10.17	345.63	10.78	335.07
Westar	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	5.60	187.28	5.93	181.33
Wisconsin	4.38	4.63	4.90	5.18	5.48	5.80	6.13	6.49	6.86	7.26	7.68	8.12	8.59	9.09	9.62	10.17	10.76	11.38	12.04	265.50	12.74	252.76

Average IRR of BOY & EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{DV}	Average 2013 - 2018 Dividend Growth Rates EOY	BOY	Average
2	Allete	1	ALE	9.0%	63.2%	3.9%	3.9%	3.9%
3	Alliant	2	LNT	8.9%	65.3%	3.9%	4.0%	3.9%
5	Avista	3	AVA	9.3%	58.4%	3.0%	3.3%	3.1%
6	Black Hills	4	BKH	8.2%	76.2%	4.8%	4.6%	4.7%
9	Cleco	5	CNL	9.5%	59.7%	8.0%	8.4%	8.2%
10	CMS	6	CMS	9.2%	56.5%	6.3%	6.4%	6.4%
21	Great Plains	7	GXP	9.1%	62.3%	5.3%	5.3%	5.3%
22	Hawaiian	8	HE	8.1%	58.1%	1.6%	1.4%	1.5%
23	IDACORP	9	IDA	9.6%	59.4%	7.6%	8.2%	7.9%
26	MGE	10	MGEE	8.8%	65.5%	4.0%	3.8%	3.9%
29	Northwestern	11	NEW	8.7%	67.7%	4.8%	4.7%	4.7%
31	OGE	12	OGE	8.1%	65.6%	10.1%	10.0%	10.1%
35	PGE	13	POR	8.6%	68.0%	3.7%	3.6%	3.6%
36	Pinnacle	14	PNW	9.4%	57.8%	4.3%	4.2%	4.3%
37	PNM	15	PNM	10.3%	53.4%	13.0%	13.1%	13.1%
40	Scana	16	SCG	9.2%	59.7%	4.2%	4.0%	4.1%
43	TECO	17	TE	9.7%	51.1%	2.6%	2.4%	2.5%
45	UNS	18	UNS	8.9%	66.8%	8.8%	8.1%	8.5%
47	Westar	19	WR	9.0%	62.6%	2.8%	2.8%	2.8%
48	Wisconsin	20	WEC	10.7%	47.9%	10.2%	10.5%	10.3%
	Group Average			9.24%	61.3%			

Staff Model Y – EPS Growth to Determine a Sale Terminal Value and PGE Peers
Page 1 of 2

5.78% Annual Growth Rate - Stage 3 | EPS Growth to Determine a Sale Terminal Value | EPS Growth

Staff | **Staff Model Y with Company Peers**

EOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{TV}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Sale	2043
								Initial Stage						Transition Stage					Final Stage																						
2	Allete	1	ALE	9.3%	70.2%	0.00	(50.78)	1.90	1.96	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.76	2.91	3.07	3.26	3.44	3.64	3.85	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.38	6.75	7.14	7.55	7.99	331.70	8.45	322.33	
			e					2.60	2.75	2.88	3.23	3.50	3.77	4.01	4.26	4.52	4.80	5.09	5.38	5.69	6.02	6.37	6.74	7.13	7.54	7.97	8.43	8.92	9.44	9.98	10.56	11.17	11.82	12.50	13.22	13.99	14.80		15.65		16.56
3	Alliant	2	LNT	8.9%	67.7%	0.00	(53.57)	1.88	1.96	2.04	2.12	2.20	2.28	2.38	2.49	2.59	2.70	2.82	2.98	3.15	3.34	3.53	3.73	3.95	4.18	4.42	4.67	4.94	5.23	5.53	5.85	6.19	6.55	6.93	7.33	7.75	8.20	308.72	8.67	300.05	
			e					3.25	3.45	3.62	3.81	4.00	4.19	4.45	4.71	4.99	5.29	5.59	5.92	6.26	6.62	7.00	7.41	7.84	8.29	8.77	9.29	9.81	10.38	10.98	11.61	12.28	12.99	13.75	14.54	15.38	16.27		17.21		18.20
5	Avista	3	AVA	9.5%	63.7%	0.00	(29.40)	1.22	1.28	1.32	1.36	1.40	1.44	1.50	1.56	1.62	1.68	1.75	1.85	1.96	2.07	2.19	2.32	2.45	2.59	2.74	2.90	3.07	3.25	3.44	3.63	3.84	4.07	4.30	4.55	4.81	5.09	184.15	5.39	178.77	
			e					1.80	1.85	1.97	2.11	2.25	2.39	2.56	2.75	2.94	3.14	3.35	3.55	3.75	3.97	4.20	4.44	4.70	4.97	5.26	5.56	5.88	6.22	6.58	6.96	7.37	7.79	8.24	8.72	9.22	9.75		10.32		10.92
6	Black Hills	4	BKH	8.7%	87.5%	0.00	(55.91)	1.52	1.56	1.64	1.72	1.80	1.88	1.96	2.04	2.12	2.21	2.30	2.43	2.57	2.72	2.87	3.04	3.22	3.40	3.60	3.81	4.03	4.26	4.51	4.77	5.04	5.33	5.64	5.97	6.31	6.68	400.34	7.06	293.28	
			e					2.75	2.60	2.80	3.02	3.26	3.48	3.89	4.34	4.83	5.36	5.94	6.29	6.65	7.04	7.44	7.87	8.33	8.81	9.32	9.86	10.43	11.03	11.67	12.34	13.05	13.81	14.61	15.45	16.34	17.29		18.29		19.34
9	Cleco	5	CNL	9.6%	84.8%	0.00	(49.41)	1.43	1.58	1.71	1.85	2.00	2.15	2.36	2.68	2.82	3.06	3.36	3.55	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.30	7.80	8.25	8.73	9.24	9.77	322.58	10.33	312.24	
			e					2.60	2.75	2.88	3.23	3.50	3.77	4.00	4.25	4.60	4.77	5.06	5.34	5.65	5.98	6.32	6.69	7.07	7.48	7.91	8.37	8.86	9.37	9.91	10.48	11.09	11.73	12.41	13.12	13.88	14.68		15.53		16.43
10	CMS	6	CMS	9.4%	56.8%	0.00	(28.28)	1.02	1.08	1.15	1.22	1.30	1.38	1.47	1.58	1.68	1.80	1.92	2.03	2.14	2.27	2.40	2.54	2.68	2.84	3.00	3.18	3.36	3.56	3.78	3.99	4.21	4.45	4.71	4.98	5.27	5.57	157.73	5.90	151.84	
			e					1.65	1.75	1.83	1.91	2.00	2.09	2.20	2.32	2.45	2.58	2.72	2.88	3.05	3.22	3.41	3.61	3.81	4.03	4.27	4.51	4.77	5.05	5.34	5.65	5.98	6.32	6.69	7.08	7.48	7.92		8.37		8.86
21	Great Plains	7	GXP	9.4%	69.6%	0.00	(25.84)	0.88	0.94	0.99	1.04	1.10	1.16	1.22	1.28	1.35	1.42	1.49	1.58	1.67	1.77	1.87	1.98	2.09	2.21	2.34	2.48	2.62	2.77	2.93	3.10	3.28	3.47	3.67	3.88	4.10	4.34	173.14	4.59	168.55	
			e					1.56	1.66	1.76	1.88	2.00	2.12	2.30	2.48	2.68	2.89	3.11	3.29	3.48	3.69	3.89	4.11	4.35	4.60	4.87	5.15	5.45	5.76	6.10	6.45	6.82	7.22	7.63	8.07	8.54	9.03		9.56		10.11
22	Hawaiian	8	HE	8.6%	52.1%	0.00	(25.51)	1.24	1.24	1.26	1.28	1.30	1.32	1.33	1.35	1.36	1.37	1.39	1.47	1.55	1.64	1.74	1.84	1.94	2.06	2.18	2.30	2.43	2.57	2.72	2.88	3.05	3.22	3.41	3.61	3.82	4.04	108.73	4.27	104.45	
			e					1.60	1.60	1.65	1.70	1.75	1.80	1.84	1.88	1.93	1.97	2.01	2.13	2.25	2.38	2.52	2.67	2.82	2.98	3.16	3.34	3.53	3.74	3.96	4.19	4.42	4.68	4.95	5.23	5.54	5.86		6.19		6.55
23	IDACORP	9	IDA	8.6%	46.3%	0.00	(54.81)	1.57	1.75	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.78	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	207.80	11.57	196.23	
			e					3.50	3.45	3.50	3.55	3.60	3.65	3.69	3.74	3.78	3.82	3.86	4.09	4.32	4.57	4.84	5.12	5.41	5.73	6.06	6.41	6.78	7.17	7.59	8.02	8.49	8.98	9.50	10.05	10.63	11.24		11.89		12.58
26	MGE	10	MGEE	8.9%	68.3%	0.00	(44.83)	1.61	1.65	1.72	1.79	1.86	1.93	2.00	2.08	2.16	2.24	2.32	2.45	2.60	2.75	2.90	3.07	3.25	3.44	3.64	3.85	4.07	4.30	4.55	4.82	5.09	5.39	5.70	6.03	6.38	6.75	260.74	7.14	253.61	
			e					3.15	3.30	3.47	3.66	3.85	4.04	4.30	4.57	4.86	5.16	5.48	5.79	6.13	6.48	6.86	7.25	7.67	8.11	8.58	9.08	9.60	10.16	10.75	11.37	12.02	12.72	13.45	14.23	15.05	15.92		16.84		17.82
29	Northwestern	11	NWE	8.4%	64.6%	0.00	(45.68)	1.52	1.56	1.64	1.72	1.80	1.88	1.98	2.04	2.13	2.22	2.31	2.44	2.58	2.73	2.89	3.05	3.23	3.42	3.61	3.82	4.04	4.28	4.53	4.79	5.06	5.36	5.67	5.99	6.34	6.71	225.56	7.09	218.47	
			e					2.60	2.70	2.80	2.90	3.00	3.10	3.23	3.37	3.51	3.65	3.80	4.02	4.26	4.50	4.76	5.04	5.33	5.64	5.96	6.31	6.67	7.06	7.47	7.90	8.35	8.84	9.35	9.89	10.46	11.06		11.70		12.38
31	OGE	12	OGE	8.8%	63.7%	0.00	(35.38)	0.84	0.93	1.03	1.13	1.25	1.37	1.50	1.65	1.81	1.98	2.16	2.29	2.42	2.56	2.71	2.87	3.03	3.21	3.39	3.59	3.80	4.02	4.25	4.49	4.75	5.03	5.32	5.63	5.96	6.30	190.84	6.66	183.98	
			e					1.85	2.00	2.08	2.16	2.25	2.34	2.45	2.57	2.69	2.82	2.96	3.13	3.31	3.50	3.70	3.92	4.14	4.38	4.63	4.90	5.19	5.49	5.80	6.14	6.49	6.87	7.26	7.68	8.13	8.60		9.10		9.62
35	PGE	13	POR	8.9%	72.1%	0.00	(31.32)	1.09	1.12	1.16	1.21	1.26	1.29	1.34	1.38	1.43	1.47	1.52	1.61	1.70	1.80	1.91	2.02	2.13	2.25	2.39	2.52	2.67	2.82	2.99	3.16	3.34	3.53	3.74	3.96	4.18	4.43	188.22	4.68	183.54	
			e					1.65	1.85	1.97	2.11	2.25	2.39	2.50	2.61	2.73	2.85	2.97	3.14	3.32	3.52	3.72	3.93	4.16	4.40	4.66	4.93	5.21	5.51	5.83	6.17	6.52	6.90	7.30	7.72	8.17	8.64		9.14		9.67
36	Pinnacle	14	PNW	9.0%	53.7%	0.00	(54.35)	2.20	2.29	2.39	2.49	2.60	2.71	2.82	2.94	3.06	3.18	3.31	3.50	3.70	3.92	4.14	4.38	4.64	4.90	5.19	5.49	5.80	6.14	6.50	6.87	7.27	7.69	8.13	8.60	9.10	9.63	256.27	10.18	246.09	
			e					3.55	3.70	3.80	3.90	4.00	4.10	4.26	4.42	4.59	4.76	4.94	5.22	5.53	5.85	6.18	6.54	6.92	7.32	7.74	8.19	8.66	9.16	9.69	10.25	10.85	11.47	12.14	12.84	13.58	14.37		15.20		16.07
37	PNM	15	PNM	10.9%	71.0%	0.00	(25.81)	0.66	0.74	0.84	0.95	1.08	1.21	1.37	1.56	1.76	1.98	2.23	2.35	2.49	2.63	2.79	2.95	3.12	3.30	3.49	3.69	3.90	4.13	4.37	4.62	4.89	5.17	5.47	5.79	6.12	6.47	251.26	6.85	244.41	
			e					1.40	1.50	1.69	1.91	2.15	2.30	2.67	2.99	3.31	3.67	4.06	4.29	4.54	4.80	5.08	5.37	5.69	6.01	6.36	6.73	7.12	7.53	7.96	8.42	8.91	9.43	9.97	10.55	11.16	11.80		12.48		13.21
40	Scana	16	SCG	9.3%	63.6%	0.00	(48.94)	2.02	2.03	2.12	2.21	2.30	2.39	2.47	2.55	2.64	2.72	2.81	2.97	3.14	3.32	3.52	3.72	3.93	4.16	4.40	4.66	4.92	5.21	5.51	5.83	6.17	6.52	6.90	7.30	7.72	8.17	292.84	8.64	284.20	
			e					3.40	3.55	3.77	4.00	4.25	4.50	4.78	5.08	5.39	5.72	6.07	6.42	6.79	7.18	7.60	8.03	8.50	8.99	9.51	10.06	10.64	11.26	11.91	12.59	13.32	14.09	14.91	15.77	16.68	17.64		18.66		19.74
43	TECO	17	TE	10.1%	59.2%	0.00	(16.64)	0.88	0.88	0.90	0.93	0.95	0.97	0.99	1.01	1.03	1.05	1.07	1.13	1.19	1.26	1.34	1.41	1.50	1.58	1.67	1.77	1.87	1.98	2.10	2.22	2.35	2.48	2.62	2.78	2.94	3.11	111.28	3.29	108.00	
			e					0.92	0.96	1.07	1.20	1.35	1.50	1.56	1.63	1.69	1.76	1.84	1.94	2.05	2.17	2.30	2.43	2.57	2.72	2.88	3.04	3.22	3.40	3.60	3.81	4.03	4.26	4.51	4.77	5.05	5.34		5.65		5.97
45	UNS	18	UNS	8.9%	69.8%	0.00	(60.17)	1.74	1.76	1.92	2.09	2.28	2.47	2.62	2.78	2.95	3.12	3.31	3.50	3.70	3.91	4.14	4.38	4.63	4.90	5.18	5.48	5.80	6.13	6.49	6.86	7.26	7.68	8.12	8.59	9.09	9.61	361.52	10.17	351.35	
			e					3.12	3.40	3.53	3.66	3.80	3.94	4.23	4.55	4.88	5.23	5.60	5.92	6.26	6.63	7.01	7.41	7.84	8.30	8.78	9.28	9.82	10.39	10.99	11.62	12.29	13.00	13.76	14.55	15.39	16.28		17.22		18.22
47	Westar	19	WR	9.0%	65.5%	0.00	(34.03)	1.35	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	196.71	5.60	191.10	
			e					2.25	2.35	2.48	2.61	2.75	2.89	3.07	3.26	3.45	3.66	3.88	4.10	4.34	4.59	4.85	5.13	5.43	5.74	6.08	6.43	6.80	7.19	7.61	8.05	8.51	9.00	9.52	10.08	10.66	11.27		11.93		12.61
48	Wisconsin	20	WEC	10.6%	62.6%	0.00	(42.78)	1.45	1.56	1.72	1.90	2.10	2.30	2.57	2.86	3.18	3.53	3.91	4.14	4.38	4.63	4.90	5.18	5.48	5.80	6.13	6.49	6.86	7.26	7.68	8.12	8.59	9.09	9.62	10.17	10.76	11.38	289.87	12.04	277.83	
			e					2.45	2.60	2.80	3.02	3.25	3.48	3.73	4.00	4.28	4.56	4.89	5.17	5.47	5.79	6.12	6.48	6.85	7.25	7.67	8.11	8.58	9.07	9.60	10.15	10.74	11.36	12.02	12.71	13.45	14.23		15.05		15.92
				9.2%	64.1%	0.00																																			

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Staff Model Y – EPS Growth to Determine a Sale Terminal Value and PGE Peers

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BOY Cash Flows

Screen	Staff's Peer Utilities	Set	Ticker	IRR	Terminal Value as % of NPV_{TV}	NPV @ IRR	Recent Price*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2042 Terminal Value	2043 Div	2043 Perpetuity	
								Initial Stage						Transition Stage					Final Stage																						
2	Allete	1	ALE	9.4%	67.8%	0.00	(50.78)	1.96	2.04	2.12	2.20	2.28	2.37	2.46	2.55	2.65	2.75	2.91	3.07	3.25	3.44	3.64	3.85	4.07	4.31	4.55	4.82	5.10	5.39	5.70	6.03	6.39	6.76	7.14	7.56	7.99	8.46	332.27	8.94	323.33	
			e					2.60	2.76	2.98	3.23	3.50	3.77	4.01	4.26	4.62	4.80	5.09	5.38	5.69	6.02	6.37	6.74	7.13	7.54	7.97	8.43	8.92	9.44	9.98	10.56	11.17	11.82	12.50	13.22	13.99	14.80		15.65		16.56
3	Alliant	2	LNT	9.0%	65.3%	0.00	(53.57)	1.96	2.04	2.12	2.20	2.28	2.38	2.49	2.59	2.70	2.82	2.98	3.16	3.34	3.53	3.73	3.95	4.18	4.42	4.67	4.94	5.23	5.53	5.85	6.19	6.55	6.93	7.33	7.75	8.20	8.67	309.22	9.17	300.05	
			e					3.25	3.45	3.62	3.81	4.00	4.19	4.45	4.71	4.99	5.29	5.59	5.92	6.26	6.62	7.00	7.41	7.84	8.29	8.77	9.28	9.81	10.38	10.98	11.61	12.28	12.99	13.76	14.54	15.38	16.27		17.21		18.20
5	Avista	3	AVA	9.6%	61.3%	0.00	(29.48)	1.28	1.32	1.36	1.40	1.44	1.50	1.56	1.62	1.68	1.75	1.85	1.96	2.07	2.19	2.32	2.45	2.59	2.74	2.90	3.07	3.25	3.44	3.63	3.84	4.07	4.30	4.55	4.81	5.09	5.38	184.46	5.70	178.77	
			e					1.80	1.85	1.97	2.11	2.25	2.39	2.60	2.76	2.94	3.14	3.35	3.55	3.75	3.97	4.20	4.44	4.70	4.97	5.26	5.56	5.88	6.22	6.58	6.96	7.37	7.79	8.24	8.72	9.22	9.75		10.32		10.92
6	Black Hills	4	BKH	8.8%	85.2%	0.00	(55.91)	1.56	1.64	1.72	1.80	1.88	1.96	2.04	2.12	2.21	2.30	2.43	2.57	2.72	2.87	3.04	3.22	3.40	3.60	3.81	4.03	4.26	4.51	4.77	5.04	5.33	5.64	5.97	6.31	6.68	7.06	400.75	7.47	393.28	
			e					2.75	2.60	2.80	3.02	3.25	3.48	3.89	4.34	4.83	5.36	5.94	6.29	6.65	7.04	7.44	7.87	8.33	8.81	9.32	9.86	10.43	11.03	11.67	12.34	13.05	13.81	14.61	15.45	16.34	17.29		18.29		19.34
9	Cleco	5	CNL	9.8%	61.2%	0.00	(49.41)	1.56	1.71	1.85	2.00	2.15	2.36	2.58	2.82	3.08	3.36	3.55	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.97	7.38	7.80	8.25	8.73	9.24	9.77	10.33	323.18	10.93	312.24	
			e					2.50	2.75	2.98	3.23	3.50	3.77	4.00	4.25	4.50	4.77	5.05	5.34	5.65	5.98	6.32	6.69	7.07	7.48	7.91	8.37	8.86	9.37	9.91	10.48	11.09	11.73	12.41	13.12	13.88	14.68		15.53		16.43
10	CMS	6	CMS	9.7%	53.9%	0.00	(28.28)	1.08	1.15	1.22	1.30	1.38	1.47	1.58	1.68	1.80	1.92	2.03	2.14	2.27	2.40	2.54	2.68	2.84	3.00	3.18	3.36	3.56	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.90	158.07	6.24	151.84	
			e					1.65	1.75	1.83	1.91	2.00	2.09	2.20	2.32	2.45	2.58	2.72	2.88	3.05	3.22	3.41	3.61	3.81	4.03	4.27	4.51	4.77	5.05	5.34	5.65	5.98	6.32	6.69	7.08	7.48	7.92		8.37		8.86
21	Great Plains	7	GXP	9.8%	68.9%	0.00	(25.84)	0.94	0.99	1.04	1.10	1.16	1.22	1.28	1.35	1.42	1.49	1.58	1.67	1.77	1.87	1.98	2.09	2.21	2.34	2.48	2.62	2.77	2.93	3.10	3.28	3.47	3.67	3.88	4.10	4.34	4.59	173.41	4.86	168.55	
			e					1.55	1.65	1.76	1.88	2.00	2.12	2.30	2.48	2.68	2.89	3.11	3.29	3.48	3.68	3.89	4.11	4.35	4.60	4.87	5.15	5.45	5.76	6.10	6.45	6.82	7.22	7.63	8.07	8.54	9.03		9.56		10.11
22	Hawaiian	8	HE	8.8%	50.5%	0.00	(25.51)	1.24	1.26	1.28	1.30	1.32	1.33	1.35	1.36	1.37	1.39	1.47	1.55	1.64	1.74	1.84	1.94	2.06	2.18	2.30	2.43	2.57	2.72	2.89	3.05	3.22	3.41	3.61	3.82	4.04	4.27	108.97	4.52	104.46	
			e					1.60	1.60	1.65	1.70	1.75	1.80	1.84	1.88	1.93	1.97	2.01	2.13	2.25	2.38	2.52	2.67	2.82	2.98	3.16	3.34	3.53	3.74	3.95	4.18	4.42	4.68	4.95	5.23	5.54	5.86		6.19		6.55
23	IDACORP	9	IDA	8.9%	43.4%	0.00	(54.61)	1.76	1.90	2.04	2.20	2.36	2.60	2.86	3.13	3.44	3.76	3.98	4.21	4.45	4.71	4.98	5.27	5.57	5.89	6.23	6.59	6.98	7.38	7.81	8.26	8.73	9.24	9.77	10.34	10.93	11.57	208.47	12.24	196.23	
			e					3.50	3.45	3.50	3.55	3.60	3.65	3.69	3.74	3.78	3.82	3.86	4.09	4.32	4.57	4.84	5.12	5.41	5.73	6.06	6.41	6.78	7.17	7.59	8.02	8.49	8.98	9.50	10.05	10.63	11.24		11.89		12.58
26	MGE	10	MGEE	9.0%	66.0%	0.00	(44.83)	1.65	1.72	1.79	1.86	1.93	2.00	2.08	2.16	2.24	2.32	2.46	2.60	2.75	2.90	3.07	3.25	3.44	3.64	3.85	4.07	4.30	4.55	4.82	5.09	5.39	5.70	6.03	6.38	6.75	7.14	261.15	7.55	253.61	
			e					3.15	3.30	3.47	3.65	3.85	4.04	4.30	4.57	4.86	5.16	5.48	5.79	6.13	6.48	6.86	7.25	7.67	8.11	8.58	9.08	9.60	10.16	10.75	11.37	12.02	12.72	13.45	14.23	15.05	15.92		16.84		17.82
29	Northwestern	11	NEW	8.5%	62.2%	0.00	(45.88)	1.56	1.64	1.72	1.80	1.88	1.98	2.04	2.13	2.22	2.31	2.44	2.58	2.73	2.89	3.05	3.23	3.42	3.61	3.82	4.04	4.28	4.53	4.79	5.06	5.36	5.67	5.99	6.34	6.71	7.09	225.97	7.50	218.47	
			e					2.60	2.70	2.80	2.90	3.00	3.10	3.23	3.37	3.51	3.65	3.80	4.02	4.26	4.50	4.76	5.04	5.33	5.64	5.96	6.31	6.67	7.06	7.47	7.90	8.35	8.84	9.35	9.89	10.46	11.06		11.70		12.38
31	OGE	12	OGE	9.0%	60.4%	0.00	(35.38)	0.93	1.03	1.13	1.25	1.37	1.50	1.65	1.81	1.98	2.16	2.29	2.42	2.56	2.71	2.87	3.03	3.21	3.39	3.59	3.80	4.02	4.25	4.49	4.75	5.03	5.32	5.63	5.95	6.30	6.66	191.03	7.05	183.98	
			e					1.85	2.00	2.08	2.16	2.25	2.34	2.45	2.57	2.69	2.82	2.96	3.13	3.31	3.50	3.70	3.92	4.14	4.38	4.63	4.90	5.19	5.49	5.80	6.14	6.49	6.87	7.26	7.68	8.13	8.60		9.10		9.62
35	PGE	13	POR	8.9%	69.9%	0.00	(31.32)	1.12	1.16	1.21	1.25	1.29	1.34	1.38	1.43	1.47	1.52	1.61	1.70	1.80	1.91	2.02	2.13	2.26	2.39	2.52	2.67	2.82	2.99	3.16	3.34	3.53	3.74	3.96	4.18	4.43	4.68	188.49	4.95	183.54	
			e					1.65	1.85	1.97	2.11	2.25	2.39	2.50	2.61	2.73	2.85	2.97	3.14	3.32	3.52	3.72	3.93	4.16	4.40	4.65	4.93	5.21	5.51	5.83	6.17	6.52	6.90	7.30	7.72	8.17	8.64		9.14		9.67
36	Pinnacle	14	PNW	9.2%	51.3%	0.00	(54.35)	2.29	2.39	2.49	2.60	2.71	2.82	2.94	3.06	3.18	3.31	3.50	3.70	3.92	4.14	4.38	4.64	4.90	5.19	5.49	5.80	6.14	6.50	6.87	7.27	7.69	8.13	8.60	9.10	9.63	10.18	256.86	10.77	246.09	
			e					3.55	3.70	3.80	3.90	4.00	4.10	4.26	4.42	4.59	4.76	4.94	5.22	5.53	5.85	6.18	6.54	6.92	7.32	7.74	8.19	8.66	9.16	9.69	10.25	10.85	11.47	12.14	12.84	13.58	14.37		15.20		16.07
37	PNM	15	PNM	11.2%	56.4%	0.00	(26.91)	0.74	0.84	0.95	1.08	1.21	1.37	1.56	1.76	1.98	2.23	2.35	2.49	2.63	2.79	2.95	3.12	3.30	3.49	3.69	3.90	4.13	4.37	4.62	4.89	5.17	5.47	5.79	6.12	6.47	6.85	251.66	7.24	244.41	
			e					1.40	1.60	1.69	1.91	2.15	2.39	2.67	2.98	3.31	3.67	4.06	4.29	4.54	4.80	5.08	5.37	5.68	6.01	6.36	6.73	7.12	7.53	7.96	8.42	8.91	9.43	9.97	10.55	11.16	11.80		12.48		13.21
40	Scana	16	SCG	9.4%	61.3%	0.00	(48.94)	2.03	2.12	2.21	2.30	2.39	2.47	2.55	2.64	2.72	2.81	2.97	3.14	3.32	3.52	3.72	3.93	4.16	4.40	4.66	4.92	5.21	5.51	5.83	6.17	6.52	6.90	7.30	7.72	8.17	8.64	293.34	9.14	284.20	
			e					3.40	3.66	3.77	4.00	4.25	4.50	4.78	5.08	5.39	5.72	6.07	6.42	6.79	7.18	7.60	8.03	8.50	8.99	9.51	10.06	10.64	11.26	11.91	12.59	13.32	14.09	14.91	15.77	16.68	17.64		18.66		19.74
43	TECO	17	TE	10.2%	67.2%	0.00	(16.84)	0.88	0.90	0.93	0.95	0.97	0.99	1.01	1.03	1.05	1.07	1.13	1.19	1.26	1.34	1.41	1.50	1.58	1.67	1.77	1.87	1.98	2.10	2.22	2.35	2.48	2.62	2.78	2.94	3.11	3.29	111.47	3.48	108.00	
			e					0.92	0.95	1.07	1.20	1.35	1.50	1.56	1.63	1.69	1.75	1.84	1.94	2.05	2.17	2.30	2.43	2.57	2.72	2.88	3.04	3.22	3.40	3.60	3.81	4.03	4.26	4.51	4.77	5.05	5.34		5.65		5.97
45	UNS	18	UNS	9.1%	66.9%	0.00	(60.17)	1.76	1.92	2.09	2.28	2.47	2.62	2.78	2.95	3.12	3.31	3.50	3.70	3.91	4.14	4.38	4.63	4.90	5.19	5.48	5.80	6.13	6.49	6.86	7.26	7.68	8.12	8.59	9.09	9.61	10.17	362.11	10.76	351.35	
			e					3.12	3.40	3.53	3.66	3.80	3.94	4.23	4.55	4.88	5.23	5.60	5.92	6.26	6.63	7.01	7.41	7.84	8.30	8.78	9.28	9.82	10.39	10.99	11.62	12.29	13.00	13.76	14.55	15.39	16.28		17.22		18.22
47	Westar	19	WR	9.2%	63.3%	0.00	(34.09)	1.40	1.44	1.48	1.52	1.56	1.61	1.66	1.71	1.77	1.82	1.93	2.04	2.16	2.28	2.41	2.55	2.70	2.86	3.02	3.20	3.38	3.58	3.78	4.00	4.23	4.48	4.74	5.01	5.30	5.60	197.03	5.93	191.10	
			e					2.25	2.35	2.48	2.61	2.75	2.89	3.07	3.26	3.45	3.66	3.88	4.10	4.34	4.59	4.85	5.13	5.43	5.74	6.08	6.43	6.80	7.19	7.61	8.05	8.51	9.00	9.52	10.08	10.66	11.27		11.93		12.61
48	Wisconsin	20	WEC	11.0%	46.9%	0.00	(42.76)	1.56	1.72	1.90	2.10	2.30	2.57	2.86	3.18	3.53	3.91	4.14	4.38	4.63	4.90	5.18	5.48	5.80	6.13	6.49	6.86	7.26	7.68	8.12	8.59	9.09	9.62	10.17	10.76	11.38	12.04	290.57	12.74	277.83	
			e					2.45	2.60	2.80	3.02	3.25	3.48	3.73	4.00	4.29	4.58	4.89	5.17	5.47	5.79	6.12	6.48	6.85	7.25	7.67	8.11	8.58	9.07	9.60	10.15	10.74	11.36	12.02	12.71	13.45	14.23		15.05		15.92
				9.4%	61.6%	0.00																																			

Average IRR of BOY & EOY Cash Flows					Terminal Value as % of	Average 2013 - 2018 Dividend Growth Rates		
Screen	Staff's Peer Utilities	Set	Ticker	IRR	NPV_{TV}	EOY	BOY	Average
2	Allete	1	ALE	9.3%	69.0%	3.9%	3.9%	3.9%
3	Alliant	2	LNT	8.9%	66.5%	3.9%	4.0%	3.9%
5	Avista	3	AVA	9.6%	67.5%	3.0%	3.3%	3.1%
6	Black Hills	4	BKH	8.8%	86.3%	4.8%	4.6%	4.7%
9	Cleco	5	CNL	9.7%	62.9%	8.0%	8.4%	8.2%
10	CMS	6	CMS	9.6%	55.3%	6.3%	6.4%	6.4%
21	Great Plains	7	GXP	9.5%	68.2%	5.3%	5.3%	5.3%
22	Hawaiian	8	HE	8.7%	51.3%	1.6%	1.4%	1.5%
23	IDACORP	9	IDA	8.8%	44.9%	7.8%	8.2%	7.9%
26	MGE	10	MGEE	8.9%	67.2%	4.0%	3.9%	3.9%
29	Northwestern	11	NEW	8.4%	63.4%	4.8%	4.7%	4.7%
31	OGE	12	OGE	8.8%	62.1%	10.1%	10.0%	10.1%
35	PGE	13	POR	8.8%	71.0%	3.7%	3.6%	3.6%
36	Pinnacle	14	PNW	9.1%	52.6%	4.3%	4.2%	4.3%
37	PNM	15	PNM	11.1%	68.7%	13.0%	13.1%	13.1%
40	Scana	16	SCG	9.4%	62.5%	4.2%	4.0%	4.1%
43	TECO	17	TE	10.2%	68.2%	2.6%	2.4%	2.5%
45	UNS	18	UNS	9.0%	68.4%	8.8%	8.1%	8.5%
47	Westar	19	WR	9.1%	64.4%	2.8%	2.9%	2.8%
48	Wisconsin	20	WEC	10.8%	50.7%	10.2%	10.5%	10.3%
	Group Average			9.33%	62.9%			

CASE: UE 283
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 204

Staff Synthetic Forward Curve TIPS Analysis

Exhibits in Support
Of Opening Testimony

June 11, 2014

TIPs – Implied Average Annual Forward Inflation Rate

2023 through 2043 TIPs-Implied Average Annual Inflation Rate: 2.35%

Implied Market-based Inflationary Expectations							
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr		
2013-Q4	0.017	0.019	0.022	0.023	0.023	PGE	UE 283

Source: Federal Reserve Statistical Release H.15
See H15 Qtrly Avg for data feed

Year		Individually Implied Price Levels					Implied Forward Curve/Price Level					Implied	
Ending	Years	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr	Price Level	Check
Sep-13	0	100.00	100.00	100.00	100.00	100.00	100.00					100.00	
Sep-14	1	101.73	101.86	102.17	102.31	102.29	101.73					101.73	
Sep-15	2	103.50	103.76	104.39	104.68	104.64	103.50					103.50	
Sep-16	3	105.29	105.69	106.66	107.10	107.04	105.29					105.29	
Sep-17	4	107.12	107.66	108.98	109.58	109.49	107.12					107.12	
Sep-18	5	108.97	109.67	111.35	112.11	112.00	108.97					108.97	
Sep-19	6		111.71	113.77	114.71	114.57		111.36				111.36	
Sep-20	7		113.80	116.24	117.36	117.20		113.80				113.80	
Sep-21	8			118.77	120.08	119.89			117.10			117.10	
Sep-22	9			121.35	122.85	122.64			120.49			120.49	
Sep-23	10			123.99	125.70	125.45			123.99			123.99	
Sep-24	11				128.60	128.33				127.03		127.03	126.90
Sep-25	12				131.58	131.27				130.15		130.15	129.89
Sep-26	13				134.62	134.28				133.34		133.34	132.95
Sep-27	14				137.74	137.36				136.61		136.61	136.08
Sep-28	15				140.92	140.51				139.96		139.96	139.28
Sep-29	16				144.18	143.73				143.40		143.40	142.56
Sep-30	17				147.52	147.03				146.91		146.91	145.91
Sep-31	18				150.93	150.40				150.52		150.52	149.35
Sep-32	19				154.42	153.85				154.21		154.21	152.86
Sep-33	20				158.00	157.38				158.00		158.00	156.46
Sep-34	21					160.99					161.56	161.56	160.14
Sep-35	22					164.68					165.20	165.20	163.91
Sep-36	23					168.46					168.92	168.92	167.77
Sep-37	24					172.32					172.72	172.72	171.71
Sep-38	25					176.27					176.62	176.62	175.76
Sep-39	26					180.31					180.60	180.60	179.89
Sep-40	27					184.45					184.67	184.67	184.13
Sep-41	28					188.68					188.83	188.83	188.46
Sep-42	29					193.01					193.08	193.08	192.89
Sep-43	30					197.43					197.43	197.43	197.43

Quarterly Aggregation of H15 Data

Average Quarterly Values for FRB H15 Data

See FRB H.15 Tab for Data Feed Sources.

Staff TIPS Analysis **Quarterly Aggregation**

Average Monthly Inflation Indexed Rates by Quarter					
Qtr	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-Q1	1.33	1.81	2.07		
2003-Q2	1.15	1.61	1.94		
2003-Q3	1.36	1.84	2.21		
2003-Q4	1.24	1.65	2.01		
2004-Q1	0.82	1.26	1.71		
2004-Q2	1.26	1.69	2.05		
2004-Q3	1.17	1.55	1.89	2.28	
2004-Q4	0.93	1.30	1.69	2.08	
2005-Q1	1.17	1.41	1.71	1.93	
2005-Q2	1.30	1.44	1.68	1.83	
2005-Q3	1.59	1.70	1.82	1.98	
2005-Q4	1.92	1.98	2.04	2.13	
2006-Q1	2.00	2.05	2.09	2.08	
2006-Q2	2.34	2.39	2.46	2.48	
2006-Q3	2.37	2.37	2.37	2.38	
2006-Q4	2.40	2.36	2.32	2.29	
2007-Q1	2.28	2.33	2.33	2.36	
2007-Q2	2.35	2.40	2.44	2.49	
2007-Q3	2.38	2.44	2.45	2.46	
2007-Q4	1.54	1.81	1.92	2.11	
2008-Q1	0.58	1.02	1.32	1.81	
2008-Q2	0.79	1.17	1.48	2.03	
2008-Q3	1.18	1.47	1.70	2.16	
2008-Q4	2.73	2.92	2.60	2.73	
2009-Q1	1.37	1.54	1.79	2.34	
2009-Q2	1.12	1.37	1.72	2.31	
2009-Q3	1.17	1.41	1.74	2.22	
2009-Q4	0.58	0.94	1.37	1.98	
2010-Q1	0.47	0.94	1.43	2.00	2.16
2010-Q2	0.46	0.91	1.36	1.77	1.88
2010-Q3	0.20	0.57	1.06	1.68	1.76
2010-Q4	-0.11	0.28	0.75	1.48	1.65
2011-Q1	0.07	0.67	1.09	1.71	2.00
2011-Q2	-0.29	0.33	0.80	1.49	1.78
2011-Q3	-0.65	-0.22	0.28	0.95	1.25
2011-Q4	-0.75	-0.39	0.05	0.61	0.85
2012-Q1	-1.02	-0.60	-0.17	0.51	0.78
2012-Q2	**-1.08**	**-0.75**	**-0.35**	**0.35**	**0.66**
2012-Q3	-1.27	-1.01	-0.63	0.02	0.43
2012-Q4	**-1.42**	**-1.15**	**-0.76**	**-0.02**	**0.36**
2013-Q1	-1.40	-0.98	-0.59	0.19	0.56
2013-Q2	-1.04	-0.62	-0.25	0.47	0.80
2013-Q3	**-0.32**	**0.17**	**0.56**	**1.16**	**1.43**
2013-Q4	**-0.29**	**0.25**	**0.57**	**1.19**	**1.50**

Average Monthly Nominal UST Rates by Quarter					
Qtr	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-Q1	2.91	3.46	3.92	4.90	
2003-Q2	2.57	3.13	3.62	4.59	
2003-Q3	3.14	3.72	4.23	5.17	
2003-Q4	3.25	3.78	4.29	5.16	
2004-Q1	2.99	3.52	4.02	4.89	
2004-Q2	3.72	4.18	4.60	5.36	
2004-Q3	3.51	3.92	4.30	5.07	
2004-Q4	3.49	3.85	4.17	4.87	
2005-Q1	3.88	4.09	4.30	4.76	
2005-Q2	3.87	3.99	4.16	4.55	
2005-Q3	4.04	4.11	4.21	4.51	
2005-Q4	4.39	4.42	4.49	4.77	
2006-Q1	4.55	4.55	4.57	4.76	4.64
2006-Q2	4.99	5.02	5.07	5.29	5.14
2006-Q3	4.84	4.85	4.90	5.09	4.99
2006-Q4	4.60	4.60	4.63	4.83	4.74
2007-Q1	4.65	4.65	4.68	4.90	4.80
2007-Q2	4.76	4.79	4.85	5.07	4.99
2007-Q3	4.50	4.60	4.73	5.01	4.94
2007-Q4	3.79	3.98	4.26	4.65	4.61
2008-Q1	2.75	3.15	3.66	4.40	4.41
2008-Q2	3.16	3.46	3.89	4.59	4.58
2008-Q3	3.11	3.44	3.86	4.49	4.45
2008-Q4	2.18	2.63	3.25	3.97	3.68
2009-Q1	1.76	2.23	2.74	3.69	3.45
2009-Q2	2.23	2.88	3.31	4.19	4.17
2009-Q3	2.47	3.12	3.52	4.28	4.32
2009-Q4	2.30	2.98	3.46	4.27	4.33
2010-Q1	2.42	3.16	3.72	4.49	4.62
2010-Q2	2.25	2.93	3.49	4.20	4.37
2010-Q3	1.55	2.19	2.79	3.60	3.85
2010-Q4	1.49	2.18	2.86	3.84	4.16
2011-Q1	2.12	2.83	3.46	4.32	4.56
2011-Q2	1.86	2.55	3.21	4.07	4.34
2011-Q3	1.15	1.78	2.43	3.34	3.70
2011-Q4	0.95	1.50	2.05	2.75	3.04
2012-Q1	0.90	1.44	2.04	2.80	3.14
2012-Q2	**0.79**	**1.24**	**1.82**	**2.55**	**2.94**
2012-Q3	0.67	1.08	1.64	2.37	2.75
2012-Q4	**0.69**	**1.12**	**1.71**	**2.46**	**2.86**
2013-Q1	0.83	1.32	1.95	2.75	3.14
2013-Q2	0.92	1.39	2.00	2.78	3.15
2013-Q3	**1.51**	**2.12**	**2.71**	**3.44**	**3.72**
2013-Q4	**1.44**	**2.12**	**2.75**	**3.50**	**3.79**

Implied Market-based Inflationary Expectations					
Qtr	5-Yr	7-Yr	10-Yr	20-Yr	30-Yr
2003-Q1	1.58	1.65	1.85		
2003-Q2	1.42	1.52	1.68		
2003-Q3	1.78	1.87	2.03		
2003-Q4	2.01	2.13	2.28		
2004-Q1	2.17	2.26	2.31		
2004-Q2	2.47	2.50	2.55		
2004-Q3	2.34	2.37	2.41	2.79	
2004-Q4	2.56	2.55	2.48	2.79	
2005-Q1	2.72	2.68	2.58	2.83	
2005-Q2	2.57	2.55	2.48	2.72	
2005-Q3	2.44	2.41	2.39	2.52	
2005-Q4	2.47	2.44	2.45	2.64	
2006-Q1	2.55	2.50	2.48	2.69	
2006-Q2	2.65	2.62	2.61	2.80	
2006-Q3	2.47	2.48	2.52	2.71	
2006-Q4	2.20	2.24	2.31	2.54	
2007-Q1	2.36	2.32	2.35	2.54	
2007-Q2	2.41	2.39	2.41	2.58	
2007-Q3	2.13	2.16	2.28	2.55	
2007-Q4	2.24	2.17	2.34	2.54	
2008-Q1	2.17	2.13	2.34	2.59	
2008-Q2	2.37	2.29	2.40	2.56	
2008-Q3	1.93	1.96	2.16	2.33	
2008-Q4	-0.55	-0.29	0.65	1.24	
2009-Q1	0.39	0.69	0.95	1.35	
2009-Q2	1.11	1.51	1.60	1.88	
2009-Q3	1.30	1.72	1.77	2.06	
2009-Q4	1.72	2.04	2.09	2.29	
2010-Q1	1.96	2.22	2.28	2.49	2.47
2010-Q2	1.80	2.03	2.13	2.43	2.49
2010-Q3	1.35	1.63	1.73	1.92	2.09
2010-Q4	1.59	1.90	2.12	2.36	2.51
2011-Q1	2.05	2.16	2.37	2.61	2.56
2011-Q2	2.15	2.22	2.41	2.57	2.56
2011-Q3	1.81	2.00	2.15	2.39	2.45
2011-Q4	1.71	1.89	1.99	2.14	2.19
2012-Q1	1.92	2.04	2.20	2.29	2.36
2012-Q2	**1.86**	**1.99**	**2.17**	**2.21**	**2.28**
2012-Q3	1.94	2.09	2.28	2.35	2.31
2012-Q4	**2.11**	**2.27**	**2.47**	**2.48**	**2.50**
2013-Q1	2.23	2.31	2.54	2.55	2.58
2013-Q2	1.95	2.01	2.25	2.32	2.34
2013-Q3	**1.82**	**1.95**	**2.15**	**2.29**	**2.29**
2013-Q4	**1.73**	**1.86**	**2.17**	**2.31**	**2.29**

Structured Raw FED H.15 UST Data

FRB H.15 Market Yield on U.S. Treasury (UST) Securities at Constant Maturity, Quoted on an Investment Basis in Percent per Year | Last Updated: 1-Apr-14 @ http://www.federalreserve.gov/releases/H1...

Staff Accessed , April 2, 2014 at: http://federalreserve.gov/releases/h15/data.htm

Monthly

	Year	Inflation Indexed	H.15 ID
TIPS-05m	5		RIFLGFCY05_XII_N.M
TIPS-07m	7		RIFLGFCY07_XII_N.M
TIPS-10m	10		RIFLGFCY10_XII_N.M
TIPS-20m	20		RIFLGFCY20_XII_N.M
TIPS-30m	30		RIFLGFCY30_XII_N.M

Month	TIPS-05m	TIPS-07m	TIPS-10m	TIPS-20m	TIPS-30m
2003-01	1.65	2.10	2.29		
2003-02	1.24	1.74	1.99		
2003-03	1.09	1.60	1.94		
2003-04	1.36	1.85	2.18		
2003-05	1.18	1.61	1.91		
2003-06	0.91	1.37	1.72		
2003-07	1.30	1.76	2.11		
2003-08	1.48	1.97	2.32		
2003-09	1.29	1.80	2.19		
2003-10	1.21	1.68	2.08		
2003-11	1.27	1.64	1.96		
2003-12	1.23	1.64	1.98		
2004-01	1.09	1.48	1.89		
2004-02	0.86	1.31	1.76		
2004-03	0.52	0.96	1.47		
2004-04	1.02	1.49	1.90		
2004-05	1.34	1.77	2.09		
2004-06	1.41	1.80	2.15	TIPS-20	
2004-07	1.29	1.68	2.02	2.44	
2004-08	1.12	1.51	1.86	2.23	
2004-09	1.10	1.48	1.80	2.16	
2004-10	0.97	1.35	1.73	2.13	
2004-11	0.90	1.27	1.68	2.09	
2004-12	0.92	1.28	1.67	2.02	
2005-01	1.13	1.40	1.72	1.98	
2005-02	1.08	1.33	1.63	1.85	
2005-03	1.29	1.49	1.79	1.95	
2005-04	1.23	1.42	1.71	1.87	
2005-05	1.28	1.41	1.65	1.82	
2005-06	1.39	1.49	1.67	1.80	
2005-07	1.67	1.75	1.88	2.00	
2005-08	1.71	1.79	1.89	2.02	
2005-09	1.40	1.56	1.70	1.93	
2005-10	1.70	1.82	1.94	2.09	
2005-11	1.97	2.03	2.06	2.16	
2005-12	2.09	2.10	2.12	2.14	
2006-01	1.93	1.98	2.01	2.05	
2006-02	1.98	2.02	2.05	2.01	
2006-03	2.08	2.16	2.20	2.17	
2006-04	2.26	2.34	2.41	2.43	
2006-05	2.30	2.36	2.45	2.48	
2006-06	2.45	2.48	2.53	2.54	
2006-07	2.48	2.48	2.51	2.52	
2006-08	2.27	2.29	2.29	2.31	
2006-09	2.38	2.35	2.32	2.31	
2006-10	2.51	2.45	2.41	2.36	
2006-11	2.41	2.35	2.29	2.23	
2006-12	2.28	2.28	2.25	2.26	
2007-01	2.47	2.47	2.44	2.42	
2007-02	2.34	2.38	2.36	2.38	
2007-03	2.04	2.14	2.18	2.27	
2007-04	2.12	2.20	2.26	2.35	
2007-05	2.29	2.32	2.37	2.45	
2007-06	2.65	2.67	2.69	2.67	
2007-07	2.60	2.63	2.64	2.62	
2007-08	2.39	2.45	2.44	2.47	
2007-09	2.14	2.24	2.26	2.30	
2007-10	2.01	2.15	2.20	2.28	
2007-11	1.35	1.65	1.77	1.99	
2007-12	1.27	1.62	1.79	2.08	
2008-01	0.66	1.24	1.47	1.81	
2008-02	0.65	1.09	1.41	1.87	
2008-03	0.23	0.73	1.09	1.76	
2008-04	0.62	1.00	1.36	1.91	
2008-05	0.79	1.16	1.46	2.00	
2008-06	0.87	1.35	1.63	2.19	
2008-07	0.84	1.24	1.57	2.09	
2008-08	1.15	1.47	1.68	2.15	
2008-09	1.55	1.71	1.85	2.25	
2008-10	2.75	2.96	2.75	2.87	
2008-11	3.69	3.84	2.89	3.00	
2008-12	1.76	1.96	2.17	2.32	
2009-01	1.59	1.72	1.91	2.46	
2009-02	1.29	1.48	1.75	2.31	
2009-03	1.23	1.43	1.71	2.26	
2009-04	1.11	1.29	1.57	2.22	
2009-05	1.07	1.34	1.72	2.36	
2009-06	1.18	1.49	1.86	2.36	
2009-07	1.18	1.44	1.82	2.31	
2009-08	1.29	1.49	1.77	2.22	
2009-09	1.03	1.29	1.64	2.13	
2009-10	0.83	1.12	1.48	2.04	
2009-11	0.48	0.84	1.28	1.90	
2009-12	0.43	0.86	1.36	1.99	
2010-01	0.42	0.85	1.37	2.00	TIPS-30
2010-02	0.42	0.90	1.42	2.03	2.16
2010-03	0.56	1.06	1.51	1.98	2.15
2010-04	0.62	1.10	1.50	1.90	2.05
2010-05	0.41	0.86	1.31	1.72	1.83
2010-06	0.34	0.76	1.26	1.69	1.77
2010-07	0.34	0.73	1.24	1.80	1.87
2010-08	0.13	0.51	1.02	1.65	1.76
2010-09	0.13	0.46	0.91	1.58	1.66
2010-10	-0.32	0.02	0.53	1.32	1.44
2010-11	-0.21	0.17	0.67	1.44	1.61
2010-12	0.21	0.65	1.04	1.67	1.89
2011-01	0.06	0.62	1.06	1.70	1.97
2011-02	0.25	0.84	1.24	1.85	2.13
2011-03	-0.09	0.54	0.96	1.58	1.89
2011-04	-0.14	0.49	0.86	1.48	1.79
2011-05	-0.34	0.29	0.78	1.47	1.77
2011-06	-0.38	0.21	0.76	1.53	1.78
2011-07	-0.49	0.09	0.62	1.36	1.62
2011-08	-0.75	-0.36	0.14	0.81	1.10
2011-09	-0.72	-0.39	0.08	0.69	1.02
2011-10	-0.63	-0.28	0.19	0.72	0.99
2011-11	-0.85	-0.46	0.00	0.55	0.78
2011-12	-0.78	-0.44	-0.03	0.56	0.78
2012-01	-0.92	-0.55	-0.11	0.51	0.74
2012-02	-1.11	-0.69	-0.25	0.45	0.72
2012-03	-1.03	-0.67	-0.14	0.56	0.87
2012-04	-1.00	-0.65	-0.21	0.50	0.79
2012-05	-1.12	-0.79	-0.34	0.44	0.68
2012-06	-1.05	-0.82	-0.50	0.10	0.50
2012-07	-1.15	-0.92	-0.60	-0.01	0.39
2012-08	-1.19	-0.94	-0.59	0.08	0.47
2012-09	-1.47	-1.17	-0.71	0.02	0.44
2012-10	-1.47	-1.18	-0.75	-0.01	0.41
2012-11	-1.36	-1.13	-0.77	-0.06	0.35
2012-12	-1.40	-1.13	-0.78	0.00	0.33
2013-01	-1.39	-1.04	-0.61	0.20	0.48
2013-02	-1.39	-0.94	-0.57	0.19	0.57
2013-03	-1.43	-0.97	-0.59	0.18	0.62
2013-04	-1.38	-0.97	-0.65	0.07	0.48
2013-05	-1.14	-0.69	-0.36	0.35	0.72
2013-06	-0.69	-0.21	0.25	0.98	1.21
2013-07	-0.45	0.02	0.46	1.09	1.34
2013-08	-0.33	0.15	0.55	1.18	1.44
2013-09	-0.17	0.34	0.66	1.22	1.60
2013-10	-0.41	0.11	0.43	1.06	1.37
2013-11	-0.38	0.18	0.55	1.20	1.51
2013-12	-0.09	0.47	0.74	1.32	1.61

Monthly

	Year	H.15 ID
UST-05m	5	RIFLGFCY05_N.M
UST-07m	7	RIFLGFCY07_N.M
UST-10m	10	RIFLGFCY10_N.M
UST-20m	20	RIFLGFCY20_N.M
UST-30m	30	RIFLGFCY30_N.M

Month	UST-05m	UST-07m	UST-10m	UST-20m	UST-30m
2003-01	3.05	3.60	4.05	5.02	
2003-02	2.90	3.45	3.90	4.87	
2003-03	2.78	3.34	3.81	4.82	
2003-04	2.93	3.47	3.96	4.91	
2003-05	2.52	3.07	3.57	4.52	
2003-06	2.27	2.84	3.33	4.34	
2003-07	2.87	3.45	3.98	4.92	
2003-08	3.37	3.96	4.45	5.39	
2003-09	3.18	3.74	4.27	5.21	
2003-10	3.19	3.75	4.29	5.21	
2003-11	3.29	3.81	4.30	5.17	
2003-12	3.27	3.79	4.27	5.11	
2004-01	3.12	3.65	4.15	5.01	
2004-02	3.07	3.59	4.08	4.94	
2004-03	2.79	3.31	3.83	4.72	
2004-04	3.39	3.89	4.35	5.16	
2004-05	3.85	4.31	4.72	5.46	
2004-06	3.93	4.35	4.73	5.45	
2004-07	3.69	4.11	4.50	5.24	
2004-08	3.47	3.90	4.28	5.07	
2004-09	3.36	3.75	4.13	4.89	
2004-10	3.35	3.75	4.10	4.85	
2004-11	3.53	3.88	4.19	4.89	
2004-12	3.60	3.93	4.23	4.88	
2005-01	3.71	3.97	4.22	4.77	
2005-02	3.77	3.97	4.17	4.61	
2005-03	4.17	4.33	4.50	4.89	
2005-04	4.00	4.16	4.34	4.75	
2005-05	3.85	3.94	4.14	4.56	
2005-06	3.77	3.86	4.00	4.35	
2005-07	3.98	4.06	4.18	4.48	
2005-08	4.12	4.18	4.26	4.53	
2005-09	4.01	4.08	4.20	4.51	
2005-10	4.33	4.38	4.46	4.74	
2005-11	4.45	4.48	4.54	4.83	
2005-12	4.39	4.41	4.47	4.73	
2006-01	4.35	4.37	4.42	4.65	UST-30
2006-02	4.57	4.56	4.57	4.73	4.54
2006-03	4.72	4.71	4.72	4.91	4.73
2006-04	4.90	4.94	4.99	5.22	5.06
2006-05	5.00	5.03	5.11	5.35	5.20
2006-06	5.07	5.08	5.11	5.29	5.15
2006-07	5.04	5.05	5.09	5.25	5.13
2006-08	4.82	4.83	4.88	5.08	5.00
2006-09	4.67	4.68	4.72	4.93	4.85
2006-10	4.69	4.69	4.73	4.94	4.85
2006-11	4.58	4.58	4.60	4.78	4.69
2006-12	4.53	4.54	4.56	4.78	4.68
2007-01	4.75	4.75	4.76	4.95	4.85
2007-02	4.71	4.71	4.72	4.93	4.82
2007-03	4.48	4.50	4.56	4.81	4.72
2007-04	4.59	4.62	4.69	4.95	4.87
2007-05	4.67	4.69	4.75	4.98	4.90
2007-06	5.03	5.05	5.10	5.29	5.20
2007-07	4.88	4.93	5.00	5.19	5.11
2007-08	4.43	4.53	4.67	5.00	4.93
2007-09	4.20	4.33	4.52	4.84	4.79
2007-10	4.20	4.33	4.53	4.83	4.77
2007-11	3.67	3.87	4.15	4.56	4.52
2007-12	3.49	3.74	4.10	4.57	4.53
2008-01	2.98	3.31	3.74	4.35	4.33
2008-02	2.78	3.21	3.74	4.49	4.52
2008-03	2.48	2.93	3.51	4.36	4.39
2008-04	2.84	3.19	3.68	4.44	4.44
2008-05	3.15	3.48	3.88	4.60	4.60
2008-06	3.49	3.73	4.10	4.74	4.69
2008-07	3.30	3.60	4.01	4.62	4.57
2008-08	3.14	3.46	3.89	4.53	4.50
2008-09	2.88	3.25	3.69	4.32	4.27
2008-10	2.73	3.19	3.81	4.45	4.17
2008-11	2.29	2.82	3.53	4.27	4.00
2008-12	1.52	1.69	2.42	3.18	2.87
2009-01	1.60	1.98	2.52	3.46	3.13
2009-02	1.87	2.30	2.87	3.83	3.59
2009-03	1.82	2.42	2.82	3.78	3.64
2009-04	1.86	2.47	2.93	3.84	3.76
2009-05	2.13	2.81	3.29	4.22	4.23
2009-06	2.71	3.37	3.72	4.51	4.52
2009-07	2.46	3.14	3.56	4.38	4.41
2009-08	2.57	3.21	3.59	4.33	4.37
2009-09	2.37	3.02	3.40	4.14	4.19
2009-10	2.33	2.98	3.39	4.16	4.19
2009-11	2.23	2.92	3.40	4.24	4.31
2009-12	2.34	3.07	3.59	4.40	4.49
2010-01	2.48	3.21	3.73	4.50	4.60
2010-02	2.36	3.12	3.69	4.48	4.62
2010-03	2.43	3.16	3.73	4.49	4.64
2010-04	2.58	3.28	3.85	4.53	4.69
2010-05	2.18	2.86	3.42	4.11	4.29
2010-06	2.00	2.66	3.20	3.95	4.13
2010-07	1.76	2.43	3.01	3.80	3.99
2010-08	1.47	2.10	2.70	3.52	3.80
2010-09	1.41	2.05	2.65	3.47	3.77
2010-10	1.18	1.85	2.54	3.52	3.87
2010-11	1.35	2.02	2.76	3.82	4.19
2010-12	1.93	2.66	3.29	4.17	4.42
2011-01	1.99	2.72	3.39	4.28	4.52
2011-02	2.26	2.96	3.58	4.42	4.65
2011-03	2.11	2.80	3.41	4.27	4.51
2011-04	2.17	2.84	3.46	4.28	4.50
2011-05	1.84	2.51	3.17	4.01	4.29
2011-06	1.58	2.29	3.00	3.91	4.23
2011-07	1.54	2.28	3.00	3.95	4.27
2011-08	1.02	1.63	2.30	3.24	3.65
2011-09	0.90	1.42	1.98	2.83	3.18
2011-10	1.06	1.62	2.15	2.87	3.13
2011-11	0.91	1.45	2.01	2.72	3.02
2011-12	0.89	1.43	1.98	2.67	2.98
2012-01	0.84	1.38	1.97	2.70	3.03
2012-02	0.83	1.37	1.97	2.75	3.11
2012-03	1.02	1.56	2.17	2.94	3.28
2012-04	0.89	1.43	2.05	2.82	3.18
2012-05	0.76	1.21	1.80	2.53	2.93
2012-06	0.71	1.08	1.62	2.31	2.70
2012-07	0.62	0.98	1.53	2.22	2.59
2012-08	0.71	1.14	1.68	2.40	2.77
2012-09	0.67	1.12	1.72	2.49	2.88
2012-10	0.71	1.15	1.75	2.51	2.90
2012-11	0.67	1.08	1.65	2.39	2.80
2012-12	0.70	1.13	1.72	2.47	2.88
2013-01	0.81	1.30	1.91	2.68	3.08
2013-02	0.85	1.35	1.98	2.78	3.17
2013-03	0.82	1.32	1.96	2.78	3.16
2013-04	0.71	1.15	1.76	2.55	2.93
2013-05	0.84	1.31	1.93	2.73	3.11
2013-06	1.20	1.71	2.30	3.07	3.40
2013-07	1.40	1.99	2.58	3.31	3.61
2013-08	1.52	2.15	2.74	3.49	3.76
2013-09	1.60	2.22	2.81	3.53	3.79
2013-10	1.37	1.99	2.62	3.38	3.68
2013-11	1.37	2.07	2.72	3.50	3.80
2013-12	1.58	2.28	2.90	3.63	3.89

Annual

	Year	Inflation Indexed	H.15 ID
TIPS-05a	5		RIFLGFCY05_XII_N.A
TIPS-07a	7		RIFLGFCY07_XII_N.A
TIPS-10a	10		RIFLGFCY10_XII_N.A
TIPS-20a	20		RIFLGFCY20_XII_N.A
TIPS-30a	30		RIFLGFCY30_XII_N.A

Year	TIPS-05a	TIPS-07a	TIPS-10a	TIPS-20a	TIPS-30a
2003	1.27	1.73	2.06		
2004	1.04	1.45	1.83	2.14	
2005	1.50	1.63	1.81	1.97	
2006	2.28	2.29	2.31	2.31	
2007	2.15	2.25	2.29	2.36	
2008	1.30	1.63	1.77	2.18	
2009	1.06	1.32	1.66	2.21	
2010	0.26	0.68	1.16	1.73	1.62
2011	-0.41	0.09	0.55	1.19	1.47
2012	-1.19	-0.87	-0.48	0.22	0.56
2013	0.76	-0.29	0.07	0.75	1.07

NWN UG 221

PGE & PAC UE 262 UE 263

AVA UG 246

PGE UE 283

CASE: UE 283
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Staff Historical GDP Analysis with BEA Data

Exhibits in Support
Of Opening Testimony

June 11, 2014

CASE: UE 283
WITNESS: MATT MULDOON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 206

Representative GDP Growth Projections

Exhibits in Support
Of Opening Testimony

June 11, 2014

Representative Federal Forward GDP Projection Adjustments

Fiscal Year 2015
Budget of the U.S. Government

http://www.whitehouse.gov/sites/default/files/omb/budget/fy2015/assets/budget.pdf
http://www.whitehouse.gov/sites/default/files/omb/budget/fy2015/assets/tables.pdf

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Table S–12. Economic Assumptions[1]
(Calendar years)

	Actual	Projections											
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Gross Domestic Product (GDP):													
Nominal level, billions of dollars	16,245	16,768	17,544	18,454	19,432	20,460	21,459	22,445	23,454	24,484	25,551	26,664	27,826
Percent change, nominal GDP, year/year	4.6	3.2	4.6	5.2	5.3	5.3	4.9	4.6	4.5	4.4	4.4	4.4	4.4
Real GDP, percent change, year/year	2.8	1.7	3.1	3.4	3.3	3.2	2.8	2.5	2.4	2.3	2.3	2.3	2.3
Real GDP, percent change, Q4/Q4	2.0	2.3	3.3	3.4	3.3	3.2	2.6	2.5	2.4	2.3	2.3	2.3	2.3
GDP chained price index, percent change, year/year	1.7	1.4	1.6	1.8	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Consumer Price Index,[2] percent change, year/year	2.1	1.4	1.6	2.0	2.1	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Interest rates, percent:[3]													
91-day Treasury bills[4]	0.1	0.1	0.1	0.3	1.2	2.3	3.2	3.6	3.7	3.7	3.7	3.7	3.7
10-year Treasury notes	1.8	2.3	3.0	3.5	4.0	4.3	4.6	4.7	4.9	5.0	5.1	5.1	5.1
Unemployment rate, civilian, percent[3]	8.1	7.5	6.9	6.4	6.0	5.6	5.4	5.4	5.4	5.4	5.4	5.4	5.4

Note: A more detailed table of economic assumptions appears in Chapter 2, "Economic Assumptions and Interactions with the Budget," in the *Analytical Perspectives* volume of the Budget.
[1] Based on information available as of mid-November 2013.
[2] Seasonally adjusted CPI for all urban consumers.
[3] Annual average.
[4] Average rate, secondary market (bank discount basis).

Congress of the United States
Congressional Budget Office (CBO)
The Budget and Economic Outlook
for Calendar Years 2014 to 2024

http://www.cbo.gov/sites/default/files/cbofiles/attachments/45010-Outlook2014_Feb.pdf

Summary Table 2.

CBO's Economic Projections for Calendar Years 2014 to 2024

	Estimated, 2013	Forecast 2014	2015	2016	2017	Projected Annual Average, 2018-2024
		Fourth Quarter to Fourth Quarter (Percentage change)				
Real Gross Domestic Product	2.1	3.1	3.4	3.4	2.7	2.2
Inflation						
PCE price index	0.9	1.5	1.7	1.8	1.9	2.0
Core PCE price index[a]	1.1	1.6	1.8	1.9	1.9	2.0
Consumer price index[b]	1.2 [c]	1.9	2.1	2.1	2.3	2.4
Core consumer price index[a]	1.7 [c]	1.9	2.2	2.2	2.3	2.3

From Summary Page 1: "Beyond 2017, CBO expects that economic growth will diminish to a pace that is well below the average seen over the past several decades. That projected slowdown mainly reflects long-term trends – particularly, slower growth in the labor force because of the aging of the population. Inflation, as measured by the change in the price index for personal consumption expenditures (PCE), will remain at or below 2.0 percent throughout the next decade, CBO anticipates."

Energy Information Administration (EIA)
Annual Energy Outlook (AEO)
2014 Early Release Overview

http://www.cbo.gov/sites/default/files/cbofiles/attachments/45010-Outlook2014_Feb.pdf

Table 1. Comparison of projections in the *AEO2014* and *AEO2013* Reference cases, 2011-2040 (continued)

			2025		2040	
Energy and economic factors	2011	2012	*AEO2014*	*AEO2013*	*AEO2014*	*AEO2013*
Coal (million short tons)						
Production and waste coal	1,109	1,027	1,128	1,134	1,139	1,195
Net exports	96	118	135	124	160	123
Consumption	1,003	891	993	1,010	979	1,071
Prices (2012 dollars)						
Brent spot crude oil (dollars per barrel)	113.24	111.65	108.99	119.45	141.46	165.57
West Texas Intermediate spot crude oil (dollars per barrel)	96.55	94.12	106.99	117.41	139.46	163.54
Natural gas at Henry Hub (dollars per million Btu)	4.07	2.75	5.23	4.98	7.65	7.97
Domestic coal at minemouth (dollars per short ton)	41.74	39.94	49.67	52.94	59.18	62.37
Average electricity price (cents per kilowatthour)	10.1	9.8	10.1	9.7	11.1	11.0
Economic indicators						
Real gross domestic product (billion 2005 dollars)	13,299	13,593	18,769	18,985	26,670	27,277
GDP chain-type price index (2005 = 1.000)	1.134	1.154	1.421	1.429	1.913	1.871
Real disposable personal income (billion 2005 dollars)	10,150	10,304	14,162	14,259	19,724	19,785
Value of industrial shipments (billion 2005 dollars)	5,926	6,147	8,778	8,548	10,994	10,616
Primary energy intensity (thousand Btu per 2005 dollar of GDP)	7.30	6.99	5.46	5.39	3.99	3.95
Population (millions)	312.3	314.6	347.0	356.5	380.5	404.4
Energy-related carbon dioxide emissions (million metric tons)	5,498	5,290	5,526	5,501	5,599	5,691

Note: EIA in 2014 projects a 2.23 percent lower 2040 Real GPD than a year ago.
EIA in 2014 also projects a 1.14 percent lower 2025 Real GDP than a year ago.

Expanded Federal Acronyms

Staff monitors the reporting of the agencies listed below. As a courtesy to readers of this testimony, acronyms and common terms for these agencies are expanded below

AEO	Annual Energy Outlook
BEA	DOC Bureau of Economic Analysis
BLS	DOL Bureau of Labor Statistics
CPI-U	BLS Consumer Price Index – All Urban Consumers
DOC	U.S. Department of Commerce
DOL	U.S. Department of Labor
EIA	Energy Information Administration
FRB	Board of Governors of the Federal Reserve System
FRED	Federal Reserve Bank of St. Louis's Economic Research web site
FY	U.S. Fiscal Year, October 1 through September 30
GDP	Gross Domestic Product
GDPDEF	BEA Gross Domestic Product Implicit Price Deflator
H.15	Fed Weekly Statistical Release of Historical UST Constant Maturity Data
NIPA	BEA National Income and Product Accounts
OASDI	Old-Age, Survivors, and Disability Insurance
OMB	U.S. Office of Management and Budget
SSA	Social Security Administration
UST	U.S. Treasuries

Staff Trend Analysis of Historical U.S. BEA GDP Data

BEA Current-Dollar and "Real" Gross Domestic Product

Accessed : April 1, 2014 http://www.bea.gov/national/index.htm#gdp

U.S. Department of Commerce
Bureau of Economic Analysis
http://www.bea.gov/national/index.htm

GDP is an array of expenditure and income data collected by BEA directly and through other government agencies.

Note: July 31, 2013, 14th Comprehensive Significant Revision:
BEA revised its tables back to 1929 in to order to count:
1 Artistic Works
2 Research and Development
as Capital Investments that Depreciate Over Time
rather than one time expenditures

From an Economy based on
(Industry and Manufacturing)
to one based on
(Knowledge and Information)

$$\text{GDP deflator} = \frac{\text{Nominal GDP}}{\text{Real GDP}} \times 100$$

This comprehensive revision did not cause a large percentage jump.
The relative difference of actual amounts over time changed little.

Current-Dollar and "Real" Gross Domestic Product

YR	GDP in billions of current dollars	GDP in billions of chained 2009 dollars
1929	104.6	1,055.6
1930	92.2	965.8
1931	77.4	904.1
1932	59.5	787.5
1933	57.2	777.6
1934	66.8	861.4
1935	74.3	938.2
1936	84.9	1,059.6
1937	93.0	1,113.6
1938	87.4	1,076.7
1939	93.5	1,162.6
1940	102.9	1,265.0
1941	129.4	1,488.9
1942	166.0	1,770.3
1943	203.1	2,072.0
1944	224.6	2,237.5
1945	228.2	2,215.9
1946	227.8	1,959.0
1947	249.9	1,937.6
1948	274.8	2,018.0
1949	272.8	2,007.0
1950	300.2	2,181.9

YR-Q	GDP in billions of current dollars	GDP in billions of chained 2009 dollars	Qtr#
1947q1	243.1	1,932.6	1
1947q2	246.3	1,930.4	2
1947q3	250.1	1,928.4	3
1947q4	260.3	1,958.8	4
1948q1	266.2	1,987.6	5
1948q2	272.9	2,019.9	6
1948q3	279.5	2,031.2	7
1948q4	280.7	2,033.3	8
1949q1	275.4	2,005.6	9
1949q2	271.7	1,998.8	10
1949q3	273.3	2,020.8	11
1949q4	271.0	2,002.7	12
1950q1	281.2	2,082.5	13
1950q2	290.7	2,145.5	14
1950q3	308.5	2,228.2	15
1950q4	320.3	2,271.2	16
1951q1	336.4	2,302.3	17
1951q2	344.5	2,342.3	18
1951q3	351.8	2,390.5	19
1951q4	356.6	2,395.8	20
1952q1	360.2	2,421.1	21
1952q2	361.4	2,426.2	22

1980 through 2013 Q2

Average	5.64%	Nominal
Average	2.86%	Real

LN (

	LN	
1	8.782308	1980
2	8.761816	
3	8.760296	
4	8.778649	
5	8.799149	1981
6	8.791820	
7	8.803229	
8	8.791486	
9	8.774622	1982
10	8.780065	
11	8.776445	
12	8.777432	
13	8.790437	1983
14	8.813007	
15	8.832398	
16	8.852808	
17	8.872473	1984
18	8.889887	
19	8.899676	
20	8.907626	

OLS Regression

Annualized Real LN GPD Q		
From 1980 Q1	2.93%	Through 2013 Q4

Real GDP
+ 2.5% in 2013 Q4

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.989484
R Square	0.97908
Adjusted R Square	0.978923
Standard Error	0.041821
Observations	136

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	10.96850064	10.9685006	6271.20726	2.0912E-114
Residual	134	0.234369401	0.00174903		
Total	135	11.20287004			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*
Intercept	8.774331	0.007212039	1216.62282	8.711E-273	8.760066529	8.7885948	8.760066529
X Variable 1	0.0072	9.13465E-05	79.1909544	2.091E-114	0.007053151	0.0074145	0.007053151

Staff intentionally truncates data feed and transformation. – See Staff work papers for full data feed.

CASE: UE 283
WITNESS: Lance Kaufman

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 300

Opening Testimony

June 11, 2014

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 300

PAGES 4, 21, 22, 28 AND 45

ARE CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 14-043. YOU

MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 283 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

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

A. My name is Lance Kaufman. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97302-1166.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. This testimony presents my analysis and recommendations regarding PGE's sales forecast, mailing budget, marginal cost study, line extension policy and reactive demand charge.

Q. What issues are you responsible for in this docket?

A. I am assigned as the principal analyst for retail sales revenues, the long run incremental cost study, test year revenues, line extension policy, and reactive demand charge. I am also assigned to assist with analysis of the billing determinants.

Q. Are any of those issues included in the partial settlement reached among parties to this rate case?

A. In analyzing test year revenues I identified an issue regarding the Company's test year forecast for other revenue. Parties reached agreement on this issue in the partial settlement.

Q. Which issues remain contested for which you are responsible?

A. The sales forecast, mailing budget, long run incremental cost study, line extension policy, and reactive power charge remain contested.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

Exhibit Staff/300 Opening Testimony
Exhibit Staff/301 Witness Qualification
Exhibit Staff/302 Data Request Responses
Exhibit Staff/303 Real Price Change Calculation
Exhibit Staff/304 PGE Load Forecast Presentation
Exhibit Staff/305 2013 Forecast Variance
Exhibit Staff/306 Staff Price Adjusted Forecast and Revenue
Exhibit Staff/307 Mailing Expense Calculation
Exhibit Staff/308 Mailing Expense Linear Trend
Exhibit Staff/309 Specialized Billing Allocation
Exhibit Staff/310 Customer Marginal Cost
Exhibit Staff/311 Impact of Marginal Cost Change to Rates
Exhibit Staff/312 Line Extension Refunds and Charges
Exhibit Staff/313 Sampled Utility Reactive Demand Policies

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please summarize Staff's recommendations regarding each issue.

A.

1. Sales and Load Forecast: Staff developed an alternate method of incorporating price changes into the forecast. Staff is working cooperatively with PGE to test this model and will report the results in subsequent

testimony. Staff provides a revised forecast in this testimony that corrects two errors in the current forecast. This correction increases forecasted sales by 150,000 MWh or 0.66%. This rate case's price increase is an input into the sales forecast. Staff provides a forecast for four alternate price increases that range from the filed rate increase to no real price increase. If there is no real price increase the sales forecast increases by an additional 97,000 MWh. Under current rates, Staff's forecasts increase 2015 revenues by $14.7 to $23.4 million.

2. Mailing Expenses: Staff adjusts PGE's budgeted mailing expense from $4.0 to $3.5 million, a decrease of $518,630. This adjustment is based on forecasted postage rates and forecasted pieces of mail.
3. Customer Marginal Cost: Staff modifies several portions of the customer marginal cost study. The proposed changes increase the cost allocation of Schedules 7, 38, 90, 91 and 92. The changes decrease the cost allocation of all other schedules.
4. Line Extensions: Staff proposes changes to the Company's treatment of line extension refunds. These changes streamline the refund process and prevent refunds from resulting in an increase to rate base.
5. Reactive Power Charge: Staff presents evidence that the reactive power charge is out of date and proposes that the company study the system costs of reactive power in order to update the reactive power charge.

ISSUE 1, SALES AND LOAD FORECAST

Q. Please summarize Staff's analysis of PGE's sales and load forecast.

A. PGE claims to have consistently [redacted] sales over the last 20 years.[1] This testimony describes several problems with PGE's methodology that could cause bias.[2] Staff is continuing to analyze both the nature of this bias and potential model corrections. Staff and the Company have agreed on tests for the proposed model corrections and are currently implementing these tests.

With respect to the forecast PGE uses in this rate case, Staff identifies a program error and assumption errors regarding real price changes. Correcting the first error increases forecasted sales by 76,000 MWh (about 0.66% of sales). Correcting the second error increases forecasted sales by an additional 74,000 MWh. In addition to making these corrections Staff provides examples of price adjusted forecasts based on four different results for this case. The simulated rate changes range from rates as filed to no real price increase. No real price increase leads to an additional sales forecast increase of 97,000 MWh. The rate increase used for the final forecast will depend on the final revenue requirement approved by the Commission. Under current rates, Staff's forecast adjustments increase 2015 revenues by $14.7 to $23.4 million.[3]

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[1] See Staff Exhibit 304.

[2] PGE generates a base forecast that it acknowledges is an over forecast. PGE claims the over forecast is caused by not accounting for future price increases or energy efficiency. PGE attempts to correct this with two outboard adjustments related to price and energy efficiency. Staff contends that making outboard adjustments is less effective than correcting the problems by modifying the base model.

[3] Staff's adjustments appear inconsistent with the Company's evidence that it historically has [redacted] Staff maintains these corrections for three

PURPOSE OF SALES AND LOAD FORECAST

Q. What is the sales and load forecast used for in this rate case?

A. The forecast is used to allocate revenue requirement to each schedule. This allocation is performed using the Company's marginal cost studies. The forecast is also used to determine the set of tariff rates that will allow the Company to collect its revenue requirement.

Q. How does the forecast affect the marginal cost?

A. Several portions of the marginal cost study include schedules' share of total sales (energy) and peak demand. An increase in total sales will also increase peak demand. The relationship between a schedule's marginal cost and its share of energy is usually positive.

Q. How does the forecast affect the allocation of revenue requirement?

A. The revenue requirement is spread into several different functionalized categories. The Company's proposed spread is identified in PGE Exhibit 1405/Cody Page 1. Each functional category is allocated to rate schedules using both the marginal cost study and the sales and load forecast. An increase in a schedule's forecasted customer counts, energy, or demand will increase the allocation of the revenue requirement to that rate schedule and decrease the allocation to all other schedules.

Q. How is the forecast used to determine rates?

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reasons: the Company has implemented a change in model specification that may correct the historic bias, Staff is proposing additional model changes that may lower the base forecast, and Staff's adjustments are all corrections of errors rather than changes in methods.

A. After the revenue requirement is allocated to each schedule, rates are calculated such that the Company will receive revenues equal to the total revenue requirement. Each rate schedule has several billing determinants, such as customer counts, demand, and energy. The forecasted revenue from each schedule is equal to the sum of billing determinants times the rate. For example, Schedule 7 customers pay a fixed monthly charge and a rate that varies with sales. Revenue from schedule 7 would equal the number of customers times the monthly customer charge plus energy times the energy charge. The Company calculates 2015 revenues using current rates and the sales forecast. If current rates are not sufficient to collect the allocated revenue requirement, the Company increases one or more of its prices until it is able to collect the revenue requirement.

Q. What is the effect of an incorrect forecast on customers?

A. The effect of a forecast error can be split into three parts, (i) incorrect revenue requirement, (ii.) incorrect allocation of revenue requirement, and (iii.) failure to appropriately set the revenue requirement.

i. The sales forecast primarily impacts revenue requirement through power costs. Any changes made to the sales forecast should be included in the calculation of 2015 power costs. The sales forecast can also be used to forecast other costs and revenues. Staff uses the sales forecast to escalate customer count sensitive portions of other revenues.

ii. Oregon's long run marginal cost approach to allocating revenue requirement is intended to be both fair and efficient. If the marginal cost study is accurate, but the load forecast is not accurate, the allocation of revenue requirement may not be fair depending on the level of inaccuracy specific to each rate schedule. An end result could be for at least one rate schedule to be subsidizing other rate schedules.

iii. Forecast error can still cause problems through having revenues at present rates to be inaccurately stated thereby causing error in the amount of rate increase necessary to establish rates that are fair, just and reasonable. All else equal, if 2015 actual sales are lower than forecasted the Company will realize a return on equity that is lower than that agreed to in the rate case (and hence would have required a larger rate increase). If 2015 actual sales are higher than forecasted the Company will realize a rate of return higher the one allowed in the rate case. (These statements assume current marginal rates exceed short run marginal costs.)

Q. How should the sales forecast be judged?

A. The forecast should be selected to minimize weather adjusted forecast error variance and to minimize forecast bias. Forecast error variance is the sum of the squared difference of the forecast and weather adjusted actual sales. Forecast bias is the expected value of the difference between the forecast and the weather adjusted actual values. Both of these selection criteria require comparing two or more forecast models.

THE COMPANY'S FORECAST AND METHODOLOGY

Q. Please describe the Company's sales and load forecast.

A. The Company forecast for 2015 annual calendar sales is 19,490,502 MWh. This forecast is 1.17% higher than weather normalized sales in 2013, an annual growth of 0.58%. The average annual growth between 2010 and 2013 was 0.65%. The forecast predicts that energy will increase by 1.2% in 2014 and decrease by 0.1% in 2015. Manufacturing and primary voltage service customers are driving the majority of forecasted growth. A more detailed identification of historic and future energy use by customer group is provided in PGE Exhibit 203/Nguyen-Dammen.

Q. Is the Company's forecasted growth consistent with the forecasted growth in Oregon's Economy?

A. No. The Oregon growth rate for personal income, wages and salaries, population, and housing starts are all expected to be higher in 2015 than in recent years.[4] However, the Company anticipates a lower sales growth rate in 2015 than in recent years. This result is driven by the company's anticipated price increase.

Q. Please describe PGE's forecast methodology.

A. PGE does two intermediate test year forecasts in addition to the final test year forecast. PGE refers to the three forecasts as the B (base), P (price-effect), and E (post price-effect and "incremental" EE programs) forecasts.[5] PGE's base forecast considers the effect of economic activities on electricity delivery, all else equal. The price effect forecast incorporates the impact of higher

[4] Michael Jordan, Oregon Economic and Revenue Forecast, Oregon Office of Economic Analysis. June 2014, page 13.
[5] PGE/200, Nguyen-Dammen/1.

electricity prices on delivery. The final forecast specifically builds on the price effect forecast and accounts for the savings from incremental EE programs.[6]

BASE FORECAST

Q. Does Staff have concerns with PGE's methodology for the base forecast?

B. Yes. In UE 262, Staff was concerned that PGE's specifications potentially over-fit the model with intervention variables. As part of the UE 262 settlement parties stipulated that PGE should hold a load-forecasting workshop. During the workshop Staff proposed that the Company evaluate the selection of intervention variables used in the base forecast model.[7] Staff does not think the issues with the base model that it identified in UE 262 and in the post-hearing workshop have been satisfactorily resolved in PGE's filing.

Q. Please explain what the Company did regarding the base model for this rate case?

A. PGE explored four base models. Specifically, PGE explored use of a base model:[8]

i. Without intervention variables;[9]

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[6] PGE/200, Nguyen-Dammen/1, lines 12-21.
[7] PGE/200, Nguyen-Dammen/6, lines 10 through 15.
[8] See Exhibit 302; PGE's response to Staff DR 174.
[9] PGE uses the term intervention variables to describe a set of variables that help shape the regression model to match the data. There appear to be three types of intervention variables: Trends, Steps, and Spikes. Trend variables increase at a consistent rate each period. These variables are the most useful of the intervention variables because they capture the effect of omitted variables that grow over time, and forecast this growth into the future. Step variables are variables that consist of zero prior to a particular date and one after that date. These variables account for one time increases or decreases in the dependent variable. A series of step variables can be more effective at fitting a historic data series than trend variables. However, the timing and magnitude of new steps cannot be forecasted. For this reason trend variables are preferred in situations where steps are expected in the future. Spike variables consist of zeroes in every period except one.

ii. With preliminary shape interventions;

iii. With shape interventions and parsimonious outlier interventions; and

iv. With UE 262 consistent outlier selection criteria.

The first two base models, i. and ii., are used to identify potential intervention variables. The second two base models, iii. and iv., provide two different approaches to selecting intervention variables. The Company chose to use the parsimonious model (iii.) as the base model.

Q. Has the Company evaluated the performance of the base models?

A. Yes, the Company indicates that it evaluated the four base models using an out of sample test.[10] This test consists of estimating the model coefficients using a subset of the available data and generating estimates using the remaining data. This is a generally accepted method of evaluating forecast variance and bias.[11] Unfortunately, the Company did not retain the results of the out of sample tests.[12]

Q. Has Staff evaluated the performance of the Company's base models?

A. Staff performed a similar out of sample test on the Company's parsimonious (iii.) and full intervention (iv.) models.[13] For most forecast groups the parsimonious model structure proposed by Staff in UE 262 generates a more accurate forecast.

These variables can account for bad data or random one time energy use shocks that do not fit the error pattern of the series.

[10] See PGE/200, Nguyen-Dammen/14, lines 5 and 6.

[11] See "Principles of Forecasting: A Handbook for Researchers and Practitioners" Armstrong, J. Scott (Ed.), (2001), Boston: Kluwer Academic Publishers.

[12] See Exhibit 302; PGE response to Staff DR 173.

[13] PGE did not retain the specifications used in the full intervention model. Staff uses the model specifications provided in response to Staff DR 170. For most forecast groups DR 170 appears to contain the full set of intervention variables.

Q. Does Staff agree with the model selection method used by the Company?

A. Staff agrees with using out of sample testing to support model selection. However Staff disagrees with (i.) the implementation of the tests, and (ii.) the Company's application of the test results.

i. The out of sample test should evaluate the base models after the price and efficiency adjustments have been applied rather than before. The test identifies the model that best predicts the data. The price and efficiency adjustments assume that the base model consistently fails to predict the data. If the out of sample test succeeds in identifying an unbiased forecast prior to the application of the price and elasticity adjustment, then the subsequent price and efficiency adjustments will reduce the accuracy of the forecast.

ii. The purpose of testing intervention variables is that there is no theoretical basis for their inclusion. This is because the Company has not identified real events that are directly tied to the interventions. The current method of selecting intervention variables cannot distinguish between outliers that are appropriately excluded from the model and outliers that inform the coefficient estimates of the forecast drivers. Because there is no theoretical argument to support the inclusion or exclusion of individual intervention variables, the use of such variable should be determined on a regression by regression basis. If a subset of forecast groups are more accurately modeled using the full set of intervention variables, then those forecast groups should use the full intervention model (iv.) as the base model.

PRICE ADJUSTED FORECAST

Q. Does Staff agree with the Company's price adjusted forecast methodology?

A. Staff takes issue with four aspects of the price adjustment. First, the forecasted price change is calculated incorrectly. Second, the elasticity estimates are incorrect. Third, the price adjustment is implemented incorrectly. Fourth, separating the price adjustment from the base model is less accurate than combining the two in one model.

Q. Please explain why the price change is calculated incorrectly.

A. The Company defines their price variable as average monthly real revenue per kWh when estimating the elasticity. The Company also includes the current value and three monthly lags of price in their calculation of elasticity. However, when the Company applies the elasticity response in the price adjustment model the Company does not account for the lag structure embedded into the elasticity estimate. Furthermore, the Company only applies the elasticity adjustment on the date of nominal price changes. However, real price decreases every month. Exhibit Staff 303 compares the Company's calculation of price change against Staff's calculation of price change. Accounting for the lag structure has an ambiguous effect on the calculated price change that depends on the timing and magnitude of price changes.

Accounting for monthly inflation over the entire forecast period unambiguously decreases the estimated price change.

Q. Please explain how the price adjustment is implemented incorrectly.

A. Staff compared the residential elasticity for both the elasticity model and the price adjustment model. The elasticity model estimates residential elasticity at -0.10. The price adjustment model has an implied residential elasticity of -0.23. This inconsistency is the result of a program error in the price adjustment model. This error overstates the elasticity adjustment by approximately 100,000 MWh. Correcting the error increases the forecast by approximately 0.5 percent.

Q. Please explain why the elasticity estimates are incorrect.

A. Staff finds the elasticity estimates incorrect for several reasons. These reasons are identified and defended in Staff's analysis of the elasticity model at page 15.

Q. Why does Staff propose incorporating the base model and the price adjustment model into a single model?

A. The base model is currently subject to omitted variable bias. This is because price is not included in the base regression. The coefficients of variables that are correlated with price will absorb the price effect. This decreases the efficiency of the forecast. In addition, by performing the secondary price adjustment the Company is double counting the price response of consumers.

Q. Has Staff developed a base forecast with price included?

A. Staff has developed a base model incorporating price. However, Staff has not generated a sales forecast using this model. Staff does not have the data required to generate the forecast. In Docket No. UE 262 Staff requested and received such data from the Company. However, the Company found that providing such data to Staff required considerable personnel time. In this rate case the Company has requested that Staff utilize the Company's analysts to generate forecasts with Staff models. Staff is agreeable to this. However the Company's forecasting analysts have been occupied with updating the Company's models. The Company has proposed forecasting and testing Staff's model subsequent to the June forecast update.

Q. Does Staff have any preliminary evaluation of its forecast?

A. Yes, Staff performed a similar out of sample test procedure as that applied to the Company's two base forecasts. The results were favorable to Staff's forecast. However, for the same reasons already described on page 9, this test is more appropriately applied to the forecast after it has been subjected to the two adjustment models.

Q. Does Staff recommend using the price integrated base forecast when it is available?

A. No. Staff recommends first testing the performance of both the Company's and Staff's models using an out of sample test similar to that performed on the other four base models. This test should be performed on the final adjusted forecast rather than the base forecast. These test results should be available at the time of the Staff rebuttal testimony.

ENERGY EFFICIENCY ADJUSTMENT FORECAST

Q. What is the energy efficiency adjustment forecast?

A. The energy efficiency adjustment forecast modifies the forecast to account for new energy efficiency measures. This adjustment only accounts for energy efficiency measures related to SB 838. The Energy Trust of Oregon's (ETO) forecast for 2014 and 2015 energy efficiency measures is shaped into monthly incremental savings. The monthly incremental savings are than aggregated into monthly cumulative energy savings. These savings are then allocated to each forecast group based on a historic pattern. The forecast group's cumulative energy efficiency savings are removed from the group's price adjusted forecast.

Q. Why did the Company develop the energy efficiency adjusted forecast?

A. Econometric forecasts use the historic relationship between energy sales and demand drivers to predict the future relationship between energy sales and demand drivers. Econometric forecasts are unable to fully account for changes caused by new factors, because there is not a history with which to establish a relationship. Similarly, econometric forecasts will have difficulty anticipating changes related to omitted variables. The Company contends that the base model accurately accounts for energy savings related to SB 1149 funded energy efficiency and does not account for energy savings related to SB 838 funded energy efficiency. The Company assumes that the forecast anticipates SB 1149 because it has been in effect for a sufficient period of time for trend components of the regression to absorb any past and future impacts of SB

1149. The Company assumes the forecast does not anticipate new SB 838 energy efficiency because the savings have only existed for a few periods. The short history of SB 838 also limits its impact on the estimated regression coefficients. The energy efficiency model is developed to incorporate the impact of new energy efficiency measures installed as a result of SB 838.

Q. What is Staff's assessment of the energy efficiency model?

A. The Company's concern regarding the forecast's ability to account for new energy efficiency is valid. This is a forecasting issue that many utilities struggle to resolve. However, PGE provides no empirical justification for the Company's choice to ignore all SB 1149 measures and fully adjust SB 838 measures. The Company's method of forecasting energy use by customer groups rather than customer classes limits the ability to use other methods. The focus of the ETO's energy efficiency programs change every year. Unfortunately, the ETO does not track the industry group or energy schedule of the customers receiving ETO assistance. Staff is continuing to explore solutions to this problem. Until an alternate can be demonstrated to be superior Staff recommends continuing with the Company's model.

ELASTICITY MODEL

Q. Why did the Company develop and estimate the elasticity model?

A. The Company's price adjustment model requires forecast group specific elasticity estimates. The elasticity model is developed to provide these elasticity estimates.

Q. How does the elasticity model estimate the price elasticity of demand?

A. The elasticity model estimates elasticity for each group with the following procedure:

i. Estimate a regression model of sales that includes price as an explanatory variable.

ii. Use the model estimates from (i.) to forecast demand in 2015 assuming a fixed price.

iii. Use the model estimates from (i.) to forecast demand in 2015 assuming a new fixed price that is 10 percent higher than that in step (ii.).

iv. Calculate the percent change in 2015 energy from the forecast in (ii.) to the forecast in (iii.).

v. Divide the percent change in (iv.) by 10 percent.

The numbers resulting from (v.) above are used as price elasticity estimates in the Company's price adjustment model.

Q. What is Staff's assessment of the Company's elasticity model?

A. The elasticity model is only needed because price is not included in the base model. The elasticity model represents an extra model step that introduces unnecessary noise into the forecast. In addition, the elasticity estimates generated by this model are incorrect.

Q. Please explain why Staff finds the elasticity estimates are incorrect.

A. Staff finds the elasticity estimates incorrect for four reasons:

i. The elasticity estimates span the 2001 price increases. The magnitude of this change is much greater than the proposed price change. Consumers often respond differently to large price changes than small price changes, particularly in situations where there are fixed costs to modifying behavior. High fixed costs to modifying behavior result in discontinuous price responses. Staff attempted to correct this by truncating the regression period to January 2003. The price coefficient for nearly every regression group changed in both magnitude and sign.

ii. The elasticity model includes many regression variables not included in the base model regression. The forecast of the base model differs substantially from the forecast in part (ii.) of the elasticity model above. The coefficient estimates for the price variable changes in both sign and magnitude when the base forecast model specification is used.

iii. The regression estimates in the Company's model are subject to simultaneous equations bias. The price variable used by the Company is revenue per kWh. Revenue per kWh is equal to current revenue divided by current sales volumes:

$$Rev\ per\ kWh = \frac{(Fixed\ Charge + Energy\ Charge * kWh)}{kWh}$$

The price variable enters the equations as a distributed lag variable with the current price value and three additional lags. A simplified representation of the regression equation is:

$$kWh_t = \beta_o + \beta_1 * (Demand\ Shifters_t) + \beta_2 * (Rev\ per\ kWh_t)$$

The dependent variable kWh enters as an explanatory variable through revenue per kWh. Revenue per kWh in period t is considered endogenous because it is determined in part by kWh in period t. Including endogenous variable in a regression specification is likely to cause bias in the coefficient estimates. A tractable solution to this problem is to use revenue per kwh from previous periods rather than current periods. To identify the bias caused by including an endogenous price variable Staff introduced an additional lag to all instances of the pricing variable. The coefficients for price were smaller in absolute value when all price terms were subjected to an additional one period lag.

iv. Staff's correction to the error identified in part i., ii., and iii. demonstrate that the elasticity estimates are very sensitive to model specification and sample period. The sensitivity of these estimates and the observation that the estimates can swing from positive to negative indicate that the current estimates should not be considered valid.

v. The Company's model makes ad hoc adjustments to the estimated price coefficients. The regression results identify four of twenty-five customer groups with positive price coefficients. This means that the model predicts that when price increases, four customer groups will purchase more energy. In general, price responses are expected to be negative. The Company assumes that these price response estimates are erroneous and replaces the regression specifications with positive price responses with regression specifications that do not include price. Staff objects to this ad hoc adjustment for two reasons. First, positive elasticities of demand for energy have been empirically observed by other researchers. Griffin and

Bernstein[14] demonstrate that positive price elasticities are more likely to be observed when estimating the elasticity of small customer groups.[15] The Company's positive estimates may not be errors. Second, coefficient estimates are expected to have some error. Well-formulated regressions will equally error above and below the true value. By rejecting the positive price coefficients the Company is introducing bias to the pricing model that will over estimate a negative price response.

Q. Has Staff identified alternate elasticity estimates?

A. No. Staff is currently working to incorporate the price adjustment into the base forecast. This process will nullify many of the identified issues with the elasticity adjustment. Including price in the base forecast will eliminate the need to estimate price elasticity. If Staff's model is not a demonstrable improvement over the current model Staff will generate alternate elasticity estimates.

HISTORIC FORECAST PERFORMANCE

Q. Did the Company compare the performance of the price adjusted forecast, the energy efficiency adjusted forecast, and the elasticity forecast?

A. The Company does not appear to test these models against each other or against any other model.

[14] Bernstein, M.A. and J. Griffin (2005). Regional Differences in Price-Elasticity of Demand for Energy, Rand Corporation.

[15] For example, manufacturing industries as a whole have a negative price response. However manufacturers of energy efficient equipment and materials have a positive price elasticity because demand for their products increases with a high electricity price.

Q. Has the Company provided evidence that the Company's forecast can be improved?

A. Yes. Staff Exhibit 304 contains a document provided by the Company during an on-site discussion of the load forecast. Pages 5 through 11 of Exhibit 304 presents evidence that the energy efficiency model consistently [redacted] forecasts sales. Staff is continuing to analyze the cause of the forecast bias. Staff currently believes that the bias stems from multiple sources.

i. The regression data includes the high growth era of the 1990s. This period appears to bias some forecast groups high. Structural breaks or truncated sample periods are two potential solutions.

ii. In recent months the percentage error of the forecast is larger for customers with space heat than it is for customers without space heat. Staff intends to examine if this pattern holds for previous forecasts. This indicates that the treatment of weather merits closer investigation.

iii. Several large customers are individually forecasted. The forecast for these customers tend to be higher than actual. The large customer error appears to drive the majority of the bias in manufacturing groups.

iv. The economic forecast drivers have consistently been over estimated. This is because the economic recovery following the Great Recession has not followed the pattern of other economic recoveries.

Q. Does PGE's historic [redacted] forecast of sales imply that the current forecast is too low?

A. No. The company changed its forecast significantly by reducing the number of intervention variables. Because this is a deviation from historic practice the bias of previous forecasts should not be assumed to exist in the current forecast without further analysis.

Q. Is there additional evidence that the forecast can be improved?

A. Yes. Exhibit Staff 304 indicates that the Company [redacted] forecasted weather adjusted sales by [redacted] However, the 2013 forecast filed in the general rate case under forecasted weather adjusted sales 1.88%. Exhibit Staff 305 demonstrates that transmission sales were under forecast by 500,000 MWh or 102%. The errors balance out on the system level so that the total forecast is only 1.88% below actual sales. However, the error resulted in an under allocation of costs to transmission customers. One period does not provide sufficient data to draw significant conclusions. Staff plans to closely examine forecast error in other periods and report the results in subsequent testimony.

STAFF FORECAST

Q. Does Staff have a recommended forecast for the Commission?

A. Yes. Staff recommends using the Company's base model and energy efficiency model until such time as an alternate model has been demonstrated superior. However, Staff recommends modifying the price adjustment to correct the program error and to reflect current price expectations. Staff generated five price adjustment forecasts to reflect a range of potential rate case outcomes.

Q. What are the five price changes used by Staff?

A. The revised forecasts use a range of 0, 2, 4, 8, and 11 percent real price increases. These price changes are inclusive of the 2014 general rate case price increases. The three price adjustments between 0 and 4 percent show potential average revenue per kWh change for 2015, inclusive of UE 283,UE 286, and UM 1679. Exhibit Staff 306 identifies the combined effect on revenue requirement from adjustment to the Company's filed cases that would be consistent with each assumed price change. Providing a range of potential rate increases allows the Commission to choose the forecast consistent with the Commission findings (and resulting general rate increase) in this docket.

Q. Please walk us through the columns in Exhibit Staff 306.

1) The first column represents the price change applied in the price adjustment model. The adjustment is relative to 2013 rates. The forecast filed in the 2015 general rate case was generated in December of 2013. The base forecast for 2015 anticipates neither the 2014 nor the 2015 forecast because the base forecast does not include price as an explanatory variable. The Company intends to update the forecast in June. This update will be based on data including the 2014 price changes and the price adjustment will decrease accordingly. Column (1) is an input and the other columns are results.

2) The second column indicates percentage change in Company's base revenue that equates to the given price adjustment. This column is the appropriate indicator of the effect of the current rate case on customers.

3) The third column indicates the percentage change in the Company's total revenues that equates to the given price adjustment. This number is less than column (2) because it includes several new temporary customer credits. This column is not an appropriate indicator of the long term impact of the present rate case. These values were calculated by replacing the Company's filed billing determinants with Staff's forecast. The new billing determinants resulted in a higher level of forecasted 2015 revenues under current base rates. Staff reduced the filed 2015 rate increase until the real price change matched the one used in the forecast. The required revenue requirement reduction was then calculated as the difference between revenues under Staff rates and revenues under the filed rates
4) The fourth column indicates the revenue forecast that follows from the assumed price adjustment. The revenue forecast represents the amount of revenue the Company would collect at current rates.
5) The fifth column is the amount that the filed revenue requirement would need to be reduced by to result in the given adjustment. This reduction is inclusive of all revenue requirement adjustments that occur in UE 283, UE 286, and UM 1679.
6) Column six provides the base rate revenues received by the Company if current rates remain in effect and the company experiences the sales volume in column (4).
7) Column seven highlights the difference between the base revenues forecasted by Staff and base revenues forecasted by PGE.

Q. Please walk us through the rows in Exhibit Staff 306.

A. The first three rows provide a range of potential outcomes for this rate case.

a) Row (a) assumes that there is no real price increase in 2015 relative to 2013.

b) Row (b) assumes a 2% increase in real price.

c) Row (c) assumes a 4% increase in real price.

d) Row (d) assumes an 8% increase in real price. This case is included for comparison purposes. It identifies the real price change and equivalent forecast if the revenue requirement were approved as filed. Recent stipulations make this scenario unlikely. The forecast is corrected to account for both of Staff's observed errors in the price adjustment model.

e) Row (e) assumes an 11% increase in real price. To achieve the 11% price change applied by the Company the revenue requirement would have to increase by approximately $51 million. Staff provides this row to demonstrate the impact of correcting only the program error and not the price change error.

f) Row (f) is the case as filed.

Q. Which price adjustment from Staff 306 do you recommend?

A. Staff will present a proposed revenue requirement to the Commission in rebuttal testimony. Staff will update this forecast to be consistent with the proposed revenue requirement.

Q. How does Staff apply the price changes to the forecast?

A. Staff calculates the MWh price adjustment applied by the Company to each forecast group and removes this adjustment from the energy efficiency forecast. This constitutes the zero percent price change forecast. Staff corrects the program error identified above by dividing the Company's price adjustment in half. This is an approximate adjustment[16] based on the observation that the implied elasticity of the erroneous adjustment is more than twice the elasticity estimated by the Company. The corrected price adjustment is then scaled down to match the two percent and four percent change. This scaled down amount is then added back to the zero percent price change forecast.

Q. Why did Staff work backwards from price change to revenue requirement?

A. Too many general rate case issues remain unsettled for Staff to identify an accurate revenue requirement forecast. It is more tractable to work backwards because Staff does not have a specific revenue requirement number. The price change should be derived from the final revenue requirement once that amount has been decided.

Q. Why Does Exhibit Staff 306 provide two values for an 11% change?

A. The first value identifies Staff's forecast for an 11% price change. This corrects for the program error in the Company's filed forecast. The program error causes the Company to under forecast revenue from current rates by $10.6

[16] The adjustment is approximate due to the nature of the program and its availability to Staff. Staff has notified the Company of this error and the Compnay has indicated that the June forecast update will remove this error.

million. The Staff forecast also uses an alternate method of calculating price change that accounts for inflation over the entire test year. The Company's current method of calculating price change misstates the amount of revenue increase needed to cause an 11 percent price real price increase. In addition, all three price change calculations used by Staff include a 0.25% reduction in bills related to PGE Advice No. 14-08.

Q. What does Staff think is an appropriate method of calculating the real price change?

A. The real price change is calculated using the following procedure:

i. Identify the total revenue requirement;
ii. Identify the base price changes needed to implement the total revenue requirement;
iii. Identify the net impact of the base price changes after accounting for all miscellaneous schedules;
iv. Calculate the nominal net price index for each month in 2015;
v. Deflate the nominal net price index for each month in 2015;
vi. Calculate the average real monthly net price index for 2015;
vii. Apply the price change implied by part vi. to the price adjustment model
viii. Update the billing determinants and cost allocators;
ix. Repeat steps ii. through viii. until the price change reasonably converges to a difference less than 0.1% overall rate increase or three iterations, whichever comes first.

Q. You stated earlier that PGE's past forecasts have tended to be [redacted] Does this observation conflict with your proposal to increase the sales forecast?

A. No. PGE presents its forecast as the result of a formal model. This model should be free from program and assumption errors. If the Company is not satisfied with the forecast of an error free model the Company should present a different model, or support their forecast as a judgmental forecast rather than an econometric forecast.

Q. Please compare the growth rates in the filed forecast with the growth rates in Staff's forecast.

A. Table 301 summarizes the load growths for Staff and Company models. The Company's forecasted growth (e) is below the three year average growth for all classes except Secondary and Primary classes. Staff's corrections of the Company's program errors make the residential forecast more consistent with historical growth. Staff's corrections move Secondary and Primary forecasts away from the three year average. However, Staff's revised base model is expected to have a lower forecast for secondary and primary customers. Forecasted primary sales growth is higher than in any of the last ten years.

Table 301: Forecasted and Actual Load Growth by Customer Class

Line	Forecast	Residential	Secondary	Transmission	Primary	Lighting	Total
(a)	Without Price Adjustment (0%)	0.34%	0.56%	-11%	8.33%	-3.7%	1.20%
(b)	With 2% price increase	0.22%	0.52%	-11%	8.32%	-3.7%	1.14%
(c)	With 4% price increase	0.10%	0.48%	-11%	8.31%	-3.7%	1.08%
(d)	With proposed base rates (8%)	-0.14%	0.41%	-11%	8.28%	-3.7%	0.95%

(e)	With Company Price Adjustment	-0.93%	0.24%	-11%	8.22%	-3.7%	0.57%
	Actuals						
(f)	3 year average	0.23%	0.08%	5%	1.83%	-0.4%	0.65%
(g)	10 year maximum	3.32%	3.53%	20%	5.94%	2.6%	2.68%
(h)	5 year maximum	0.72%	0.36%	20%	5.94%	0.7%	1.30%

Q. Does Staff have any caveats regarding the recommended forecasts?

A. Yes. Several of the calculations used in Staff's forecast are approximations. These approximations bring the filed forecast close to what it should be using the correct methodology and revenue requirements. They are performed in the interest of reducing the data request load on the Company, and in recognition that the Company is planning to file an updated forecast with new data, coefficients, and model specifications. Staff's proposal should be applied not to the filed forecast but to the Company's updated forecast. This update has not yet been filed. Staff's forecast is intended to indicate the direction and magnitude of the effect that Staff's corrections have on the final forecast.

FORECAST UPDATES

Q. Why is the Company planning to file an updated forecast?

A. In general, forecasts tend to be less accurate for later periods than early periods. The Company proposes to update its forecast twice during each rate case, once in June and once in September. The forecast used to determine rates in the compliance filing is usually the September forecast.

Q. Does Staff have an opportunity to submit testimony regarding the Company's final forecast update?

A. No. The current schedule has Staff's rebuttal testimony submitted in August, prior to the final forecast update. Staff has an opportunity to comment on the updated forecast in Company's compliance filing; however the compliance filing is normally not an appropriate venue to resolve major issues.

Q. Is there value in allowing the Company to modify its sales forecast after the initial filing?

A. Yes, in general an updated forecast is more likely to be accurate than an out of date forecast.

Q. What is Staff's position regarding the Company's proposal to update the forecast?

A. Staff finds that multiple forecast updates during the rate case proceeding greatly complicates the analysis of the forecast. The implementation and testing of Staff's alternate forecast methodology was postponed to accommodate the Company's June update. The Company has indicated that the June update will have both modified model specifications and revised baselines for the forecast drivers. If the Company continues to implement forecast updates the Company should follow an update protocol that enables streamlined analysis by other parties. This protocol should not allow for changes in model specification and limit changes to updating inputs only, require that the update be distributed to all parties within a week of being generated, and require that no update be submitted later than four months prior to the effective date of the general rate case tariffs.

Q. Has Staff noted any other procedural concerns?

A. The forecast methodology used in PGE's AUT filings was restricted by stipulation in UE 228. The stipulation remains in effect. PGE does not adjust the AUT load forecast when the AUT price change is less than 3% in absolute value. The result of this stipulation is that the forecast in Docket 283 may not be consistent with the forecast in Docket 286. In general, Staff prefers that forecasts generated with the same data are consistent across dockets. It would be reasonable to have the same forecast used in the AUT and the general rate case whenever a general rate occurs and hence the 3% absolute value threshold would not be applicable whenever PGE has a general rate case filing.

ISSUE 2, MAILING EXPENSE

Q. What does the Company budget for 2014 mailing expense?

A. The Company budgets $4,045,431 for 2015 mailing expense. They identify a $543,000 increase due to postage and a $223,490 increase due to material and maintenance expense.[17]

Q. Does Staff agree with this amount?

A. No, a more appropriate amount is $3,526,801.

Q. How does Staff calculate its adjustment to mailing expense?

A. Staff splits the actual 2011-2013 mailing expenses into two groups, postage and non-postage. Postage expense for 2015 is calculated by multiplying the forecasted pieces of mail by the forecasted postage rate. Non-postage expense is calculated using average actual yearly non-postage costs for 2011 through 2013. Actual costs are escalated to 2015 dollars to account for inflation. The combined total of postage and non-postage expense is then reduced by $324,526 to account for the Company's Customer Engagement Benefit.

Q. How does Staff forecast pieces of mail?

A. The average growth rate for PGE mailings between 2009 and 2013 was -1.6%. Staff projected a continuation of this growth rate in 2014 and 2015. Table 302 contains actual and forecasted pieces of mail.

Table 302

[17] Staff Exhibit 302; PGE Response to Staff DR 159.

Year	Paper Bills, Notices, and Letters*	Percent Change**
2009	11,086,753	
2010	10,929,385	-1.4%
2011	10,872,156	-0.5%
2012	10,638,644	-2.1%
2013	10,372,409	-2.5%
2014	10,201,436	-1.6%
2015	10,033,281	-1.6%

*From PGE Response to DR 368[18]
** 2014 and 2015 calculated as the average of 2010-2013

Q. What process or limits apply for how the United States Postal Service Rates decides to change postal rates?

A. The Postal Service has two types of postage rate increases. The basic increase is capped at the average CPI percent increase of the previous 12 months. In addition to the basic increase, the Postal Service may apply to the Postal Regulatory Commission (PRC) for an exigent rate increase. The current price system has been in place since the Postal Accountability and Enhancement Act of 2006. The postal rate has increased at or near the annual CPI cap every year between 2006 and 2014, but the PRC has granted only one exigent rate increase since 2006. In 2014 the PRC granted a temporary exigent rate increase of 4.3% in consideration of the temporary hardship caused by the Great Recession. The PRC limited the total amount of funds that the exigent increase may recover. It is expected to expire beginning in the third quarter of 2015.

Q. How does Staff calculate postage rates for 2015?

[18] See Exhibit 302; PGE response to Staff DR 368.

A. Staff forecasts two rate postage rate changes in 2015, which results in three different postage rates for 2015.[19] Postage rates change at the end of January. January rates are assumed to equal current rates. February is assumed to have a rate increase equal to 1.7%, the percentage change in 2015 CPI. July is expected to have a rate decrease equal to the 2014 exigent rate increase of 4.3% Staff calculates monthly postage using the forecasted rate changes.

Q. Is it possible that the 2015 rate increase will be higher than 1.7%?

A. Yes, there are two ways that the rate increase could be higher. The CPI could be higher than expected, and legislation may pass that changes the cap on postal rate increases. If the 2015 CPI is in contention it should be addressed as a separate issue. There is currently a bill under consideration titled The Postal Reform Act of 2014 (S. 1486). Section 301 of the current version of this bill increases the cap to CPI+1 percent.

Q. Is it possible that the exigent rate increase will not expire in 2015?

A. Yes, the current version of The Postal Reform Act of 2014 Section 301 (a) modifies 39 United States Code § 3661 to read "(e) RATE BASE.—The rates for market-dominant products in effect on the date of enactment of the Postal Reform Act of 2014, including any rates adjusted under this section on an expedited basis due to either extraordinary or exceptional circumstances, shall remain in effect unless adjusted in accordance with this section." If passed, this bill makes the 2014 exigent rate increase permanent.

[19] See Exhibit Staff 307.

Q. What is the history and current status of The Postal Reform Act of 2014?

A. This bill was introduced in Senate and referred to the Committee on Homeland Security and Governmental Affairs on August 1st, 2013. The bill drew opposition from many parties, including the Direct Marketing Association, American Postal Workers Union and The National Association of Letter Carriers. The Committee approved an amended version of the bill on February 6, 2014. Postal unions and commercial mailers maintain opposition to the bill.

Q. Should expectations regarding 2015 postage rates be based on current law or proposed legislation?

A. Postage rates should be based on current law. There are 8,553 bills and resolutions before the US congress and approximately 5% of these bills are expected to be made law.[20] Given the current opposition to this bill, the low probability that this bill will be made law, and the fact that relevant portions of the bill are subject to further changes, basing postage rates on the proposed bill is highly speculative.

Q. If this legislation becomes law prior to the resolution of the current rate case, what is Staff's proposed mailing expense adjustment?

A. If the legislation becomes law as written Staff expects the Postal Service to maintain the 2014 exigent rate increase and apply a 2015 rate increase of 2.7%. This results in mailing expense of $3,639,591. If the bill is substantially altered prior to passage Staff recommends revising these calculations.

[20] Source: www.govetrack.us/congress/bills accessed May 31, 2014.

Q. You have explained Staff's escalation of postage related expense. Please explain the other portions of the mailing budget.

A. Staff's forecast of non-postage expenses is a three-year average of actual expense, escalated to account for inflation. PGE indicates an increase is expected for material and maintenance expenses.[21] PGE has not demonstrated that material and maintenance expense will increase at a rate faster than inflation. The 2015 budget should be representative of normal operating expenses. A three year average of actual expenses smooths out year to year variation in material and maintenance costs.

Q. What is the Customer Engagement Benefit and why is the mailing budget reduced to account for it?

A. The Company has initiated a fee free credit card program. The costs of this program were justified by the Company in part through projected O&M savings. The Customer Engagement Benefit represents an accounting of these savings.

Q. Does Staff double count postage savings by including both a forecasted reduction in mail and the Customer Engagement Benefit?

A. No, PGE's reduction in mail volume began prior to the implementation of the fee free credit card program. In recent years mail volumes have decreased for the US as a whole. This is due to a change in consumer preferences and an ability to transmit information electronically. The benefits of the fee free credit card program were proposed as benefits that would not take place in the absence of the program. Because PGE's mail volume would continue to

[21] Exhibit Staff 302; PGE Response to Staff DR 159.

decrease absent the program, the Customer Engagement Benefit is incremental to the forecasted decrease in pieces of mail.

Q. How does Staff's forecast compare to a linear trend forecast of mailing expenses?

A. A linear trend forecast of mailing expenses is $3,417,543. This forecast is provided in Exhibit Staff 308. The linear trend forecast is significantly less than Staff's forecast. However, there are not sufficient data points to give the trend forecast accuracy. Further, it does not account for the significant rate increase in 2014. Staff does not recommend adopting a linear trend forecast for mailing expenses.

ISSUE 3, CUSTOMER MARGINAL COST STUDY

Q. What is the customer marginal cost study?

A. The customer marginal cost study identifies the long run marginal costs to the Company that stem from adding customers. This study specifically addresses costs that do not depend on the customer's energy or demand. For simplicity none of the distribution network is included in the customer marginal cost study. The Company includes meter reading, billing, and miscellaneous customer assistance programs in the customer marginal cost study.

Q. Please summarize Staffs review of the customer marginal cost study.

A. Staff reviewed the excel model calculating customer marginal cost. This review examined the assumptions, calculations, and results of the model. The key inputs to the model are department costs and historic customer count and program participation data. The key model mechanics are the calculations of allocation factors to allocate department costs to rate schedules. Staff contests several allocation factors and department costs. The departments in question are Electronic Billing, Specialized Billing, and Printing and Mailing. Staff calculates the marginal costs separately for Schedules 89 and 90 and corrects a small error in the billing calculations for lighting schedules.

Q. What is Staff's concern regarding electronic billing?

A. Electronic billing has a filed budget of $1,219,852. Electronic billing includes two categories, credit card fees and other electronic billing costs.[22] Credit card fees relate to a proposed fee free credit card program. The scope of this

[22] See Exhibit Staff 302; PGE response to Staff DR 158.

program has changed significantly from that in the filed case. The program is currently expected to apply only to residential customers. The filed marginal cost study spreads the cost of this program to all customers regardless of participation.

Q. What is Staff's proposal for electronic billing?

A. Staff proposes allocating the fee free credit card costs separately from other electronic billing costs. Because residential customers are the only customers expected to use the fee free program they should bear the full cost of the program. Further, the cost being allocated should reflect the reduced scope of the 2015 implementation of fee free credit card use. The other electronic billing costs should be allocated as filed.

Q. What is the justification for Staff's electronic billing proposal?

A. Staff's proposal more accurately assigns Company costs to cost causers. This increases both the efficiency and equity of the marginal cost study.

Q. What is Staff's concern regarding specialized billing?

A. Specialized billing has a filed budget of $783,936. Specialized billing includes billing costs related to three main programs: net metering, solar feed-in, and direct access. These costs are currently allocated only to direct access customers.[23]

Q. What is Staff's proposal for specialized billing?

[23] See Exhibit Staff 302; PGE response to Staff DR 155.

A. Staff proposes that these costs be allocated to the customer classes eligible for the programs using a weighted average of customer counts in each program. Exhibit Staff 309 identifies Staff's allocation of specialized billing costs

Q. What is the justification for Staff's specialized billing proposal?

A. Specialized billing should be allocated to all customers that utilize this service including net metering customers and solar feed-in customers.[24] Staff's proposal more accurately assigns Company costs to cost causers. This increases both the efficiency and equity of the marginal cost study.

Q. What is Staff's concern regarding printing and mailing?

A. Printing and mailing has a filed budget of $4,494,818. Printing and mailing is allocated based on number of customers. Historically all customers have received mailed bills. Recently many costumers have begun opting for electronic bill delivery.

Q. What is Staff's proposal for allocating mailing expense?

A. Staff proposes allocating printing and mailing costs based on the number of bills mailed to each schedule.

Q. What is the justification for Staff's mailing expense proposal?

A. Staff's proposal reflects the benefits of paperless billing in the marginal cost study. This benefit should be attributed to the schedules that choose to adopt paperless billing.

Q. How does the Company treat Schedules 89 and 90?[25]

---

[24] Exhibit Staff 302; PGE response to Staff DR 361 and 362 re: customer counts for net metering and solar feed-in.
[25] Schedules 89 and 90 apply to customers larger than 4000 kW and 100MWa respectively.

A. PGE averages the marginal costs of Schedules 89 and 90 together.

Q. What is Staff's adjustment?

A. Staff calculates the marginal costs of 89 and 90 separately.

Q. Why does Staff calculate the marginal costs of 89 and 90 separately?

A. No other schedules are averaged together. Schedule 90 customers place a significantly different type of cost burden on PGE than Schedule 89 customers. Staff's proposal is a more equitable calculation of marginal cost.

Q. Does Staff have any other concerns regarding the customer marginal cost study?

A. Yes, while reviewing the model, Staff identified an input error in the billing costs of the lighting schedule. The Company's response to Staff DR 163 confirms this. Staff recommends correcting this error. In addition, the Company forecasts an increase in billing hours for Schedule 15; however, there is no forecasted increase in customers for this schedule in the marginal cost study. Staff proposes 2015 billing hours equal 2014 billing hours.

Q. Has Staff identified the effects the proposals have on customers?

A. Staff was unable to implement the proposal for printing and mailing allocations or update the credit card fee expense. Exhibit Staff 310 provides Staff's version of the marginal cost study with all other proposals implemented. Staff notes that the Company may be able to more accurately implement some of the proposed changes. Staff also identified the implications of the marginal cost changes in rate design. These changes are provided in Exhibit Staff 311.

ISSUE 4, LINE EXTENSION POLICY

Q. What is Staff's proposal regarding PGE's line extension policy?

A. Staff proposes that PGE modify its line extension policy so that PGE identifies and sends line extension refunds to eligible customers when the customers become eligible for refunds, rather than refunding eligible customers only when asked by the customers to do so. Staff is also investigating whether the manner in which PGE charges its customers for line extensions tends to result in overcharges.

Q. Please describe PGE's line extension policy.

A. PGE's line extension policy is outlined in PGE Tariff Rule I. This rule identifies the Customer's responsibility for line extension costs. With some exceptions, line extension costs include all costs of building new distribution facilities to serve individual customers.

Q. Has PGE proposed any changes to the line extension policy in this docket?

A. No.

Q. Why has Staff raised the Company's line extension policy as an issue?

A. If a customer incurs line extension costs, these costs are usually the largest single utility charge that the residential customer will experience. The OPUC regularly receives customer complaints regarding line extensions. In addition to the refund identification issue noted above, Staff has determined that PGE socializes the cost of line extensions, which results in higher rates for all customers.

Q. What are line extension refunds?

A. Section 4 of Rule I outlines the conditions for refunds to customers of line extension charges. Applicants of original line extensions may qualify for a refund of original charges if additional customers utilize the new facilities within the first five years of the facility construction.

Q. How does the treatment of refunds affect rates?

A. The Company currently socializes the cost of refunds. This is because the cost of line extension refunds is not included in the cost quotes given to the additional customers that trigger a refund to the original customer receiving line-extension service. In theory, the Company should only socialize costs that it reasonably expects to recover from the new customer in future sales.

Q. Does Staff have any other concerns regarding the treatment of refunds?

A. Yes, the Company's responses to Staff data requests[26] indicate that some customers may not be aware when they are owed a refund. Further, it appears that when the Company identifies that a customer is due a refund, the Company does not automatically process and provide the refund. The result is that some customers, especially less informed customers, do not receive refunds that they are due.

Q. Has Staff identified the magnitude of this issue?

[26] Exhibit Staff 302; PGE responses to Staff DR 197 and DR 402

A. The Company's annual line extension costs amount to $11.3 million, with approximately $9.4 million capitalized to rate base every year.[27] Approximately $1.9 million dollars is funded by customer contributions. This is the total amount that is potentially affected by under-refunding customers. It is also the maximum amount that could be added to rate base through refunds. Staff has issued multiple data requests intended to identify how the Company accounts for line extensions. The Company does not appear to track line extension costs in a sufficient manner to identify either the amount of unclaimed refunds or the impact of claimed refunds on rate base.

Q. What is Staffs proposal regarding customer refunds?

A. Staff proposes that the Company identify eligible refunds and send them to the appropriate customer or customers after the refunds are identified, even if the customers do not specifically request such refunds. Staff proposes that the cost of furnishing these refunds be assigned to the new customers whose line extension request triggers the refund, rather than to rate base. Exhibit Staff 312 illustrates the proposed accounting of line extension costs, refunds, and customer charges. Under Staff's proposal the cost responsibility of each customer is independent of the timing and order of line extension requests.[28]

Q. Does Staff have any other concerns regarding line extensions?

[27] See Exhibit 302; PGE response to Staff DR 184.
[28] The timing of a line extension may still affect the refund calculation due to variance in the prorated costs.

A. Yes. In reviewing PGE's line extension policy Staff reviewed recent PGE line extension complaints. In an informal complaint to the OPUC[29] a customer notes [redacted] In response to a Staff data request, PGE indicated that the initial quote provided to the customer would be considered firm if the customer signs the line extension agreement.[30]

Q. Are PGE's customer quotes for line extensions significant?

A. Yes, the Company bills customers for quoted costs rather than actual costs. In nearly every work order that Staff reviewed, the line extension quote was higher than the actual cost, with many work orders having an actual cost less than half the amount of the job quote.[31] The identified customer complaint, the fact the Company collects the estimated charge from customers, rather than the actual cost, and the fact that the Company's estimates appear to overstate the costs, indicate that the Company may be over-collecting costs. Staff is continuing to investigate the ramifications of this accounting mechanism.

[29] See Exhibit Staff 302; PGE response to OPUC DR 199 (Complaint filed by The Black Cat Tavern/ Closed on August 6, 2010).
[30] See Exhibit 302; PGE response to Staff DR 403.
[31] See Exhibit 302; PGE response to Staff DR 397.

ISSUE 5, REACTIVE DEMAND CHARGE

Q. What does staff recommend regarding PGE's reactive demand charge?

A. Staff recommends that the Commission direct the Company to study the costs related to reactive power in order to update the reactive demand charge. And, if there appears to be a significant cost shifting due to reactive power, the Company should incorporate reactive power costs into the marginal cost study.

Q. What is reactive power?

A. Reactive power is non-working power. Energy is often thought of as voltage times current. In alternating current circuits both current and voltage levels follow sinusoidal patterns. If the peaks and troughs of the two sine waves match, than all of the power being generated at a source is being used by the equipment to perform "real" work. If the waves do not match it means that some of the power being generated is not performing any real work. A term closely related to reactive power is power factor. The power factor is real power divided by apparent (total) power.

Q. Why are utilities concerned about reactive power?

A. Utilities must build their generation, transmission and distribution facilities to meet the apparent power[32] on their system, not just the real power. All else equal, a customer with a larger amount of reactive power, or a lower power factor, places a larger burden on the utility than a customer with a low amount of reactive power.

Q. How can the Company address reactive power?

[32] Apparent power (total power) is calculated as the square root of the sum of squared real power and reactive power

A. The Company can invest in equipment that shifts the shifts the waves for current and voltage into alignment. The Company can also encourage the customer to use equipment that does not generate as much reactive power. PGE does this through a reactive power charge. The Company can also accommodate reactive power through higher facility capacity.

Q. Are the extra Company costs related to reactive power included in the marginal cost study?

A. No, the marginal cost study does not appear to account for reactive power.

Q. What is PGE's current rate for reactive power?

A. The current reactive demand charge is $0.50 for each kilovolt-ampere of reactive demand in excess of 40% of the maximum demand. PGE has not changed the reactive power charge in at least 25 years.[33]

Q. How does this compare to the reactive power charge of other utilities?

A. Staff examined the reactive power charge for three utilities: PacifiPower, Central Hudson, and ConEdison. Pacific Power charges $0.65 per kVar in excess of 40% of maximum demand. Central Hudson charges $0.83 per kVar in excess of 33% of maximum demand. ConEdison charges $1.41 per kVar in excess of 33% of maximum demand.[34]

Q. Are the three utilities identified representative of utilities with similar costs and circumstances as PGE?

A. No. The utilities identified were the first three utilities investigated by Staff.

---

[33] OPUC does not maintain PGE tariffs prior to 1987.

[34] These charges are documented in Exhibit 313

Q. What is an appropriate reactive power charge for PGE?

A. Staff has not performed a comprehensive survey of utilities reactive power charge and cannot provide guidance at this time. Staff recommends that the Company determine the cost that reactive power imposes on their system and modify charges accordingly. This study should be prepared and acted upon by January 1, 2016.

Q. Will an updated reactive power charge alleviate equity issues associated with not having reactive power included in the marginal cost study?

A. Not directly. The reactive power revenue is an offset of each schedule's demand revenue. So a higher reactive power charge will not increase the total revenues received from a schedule. If customers respond to an updated reactive power charge by self-correcting then the Company will have a lower cost burden related to reactive power and equity concerns will diminish. However, because the reactive demand charge is an offset to the demand charge, increasing the reactive demand charge will decrease the demand charge. A lower demand charge will lower the customer's incentive to maintain a high load factor.

Q. Why isn't reactive power accounted for in the marginal cost study?

A. Reactive power is difficult to measure and most residential and small non-residential meters do not measure reactive power. In addition, some types of reactive power can be off setting. In order to include reactive power in the marginal cost study the Company must determine the system costs of reactive power and select a method of allocating these costs to each schedule. The Company does not maintain the data to perform either of these actions.

Q. If residential meters do not measure customer demand, how does the Company assign demand related costs to residential customers?

A. For distribution related demand the Company uses engineering design data. The Company designs distribution facilities to meet a "model" customer. For generation and transmission related demand the Company uses a load study and a sales forecast to estimate residential demand.

Q. Could the Company use a similar method to allocate the costs related to reactive power?

A. Yes.

Q. Please restate Staff's recommendation regarding reactive power?

A. The Commission should direct the Company to study the costs related to reactive power. The reactive demand charges should be updated to reflect the study. If there appears to be a significant cost shift due to reactive power then the Company should incorporate reactive power costs into the marginal cost study.

Q. Does this conclude your direct testimony?

A. Yes.

CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME:	Lance Kaufman
EMPLOYER:	PUBLIC UTIILTY COMMISSION OF OREGON
TITLE:	Utility Economist
ADDRESS:	3930 FAIRVIEW INDUSTRIAL DR SE, SALEM, OREGON 97302-1166
EDUCATION:	Bachelor of Business Administration, Economics, University of Alaska Anchorage 2005 Masters of Science, Economics, University of Oregon, 2009 Philosophical Doctorate, Economics, University of Oregon, 2013
EXPERIENCE:	I have been employed as a Utility Economist at the Public Utility Commission since February, 2013. My current responsibilities include analysis and technical support for rate, finance, and audit related proceedings, with an emphasis on forecasting and marginal cost studies. Prior to working for the OPUC I was an Economics instructor at the University of Oregon. I have taught courses in Public Finance and Public Economics, Urban and Regional Economics, and Microeconomics. Previous to working for the University of Oregon, I worked as a Research Assistant for Impact Assessment Inc.

CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

REDACTED
June 11, 2014

EXHIBIT 302 TABLE OF CONTENTS

March 26, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 155
Dated March 12, 2014

Request:

Please refer to UE 283/PGE/1300 Werner-Gariety Workpaper "2015 TY - Customer Marginal Cost - Work papers_Final.xlsx" sheet "summary of 2012" and sheet "12 Determinants". Specialized Billing department 439 had a 2012 budget of $848,139. This appears to represent the billing cost for 495 direct access customers. Please build up the 2012 actuals for department 439 and explain why each direct access customer is responsible for approximately $1,700 in billing costs.

Response:

See the "2012 Actuals" worksheet and filter column D "dept_id" for 439 to get a breakdown of the 2012 actuals. Column H "Act_2012" contains an itemization of the costs assigned to department 439 – Specialized Billing.

Department 439 had an actual total billing expense of $848,139 in 2012. The expenses for the department do not reflect billing costs from only direct access customers. The department also manages billing expenses from daily price option, hourly price option, net metering, qualifying facilities, solar payment option, and street lighting.
The billing determinant used to spread the expenses across the PGE rate schedules for department 439 is the number of direct access customers in 2012. The allocation percentage is also determined using the number of direct access customers. The expenses are then spread across the rate schedules based on the allocation percentage. This is a continuation of the methodology used in UE 262.

March 26, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 158
Dated March 12, 2014

Request:

Please explain why the budget for department 454 Electronic Bill increases by $849,823 or 230% from 2012 to 2015.

Response:

The increase is due to additional transaction costs associated with our third-party vendor for bankcard payments. Please see PGE's response to OPUC Data Request No. 209 for more detail.

March 26, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 159
Dated March 12, 2014

Request:

Please explain why the budget for department 727 Printing and Auto increases by $766,490 or 21% from 2012 to 2015.

Response:

Department 727 – Printing and Auto manages the printing and mail service for PGE customers. The increase in expenses from 2012 Actuals to 2015 Budget is primarily due to increased transactional costs associated with these services. The major cost driver for $543,000 of the increase is due to increased postage costs between 2012 and 2015. The remaining $223,490 is due to increased material and maintenance expenses for providing all printed correspondence. PGE currently provides paper bills and other mailings to approximately 85% of total customers.

March 26, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 165
Dated March 12, 2014

Request:

Please refer to UE 283/PGE/1300 Werner-Gariety Workpaper "2015 TY - Customer Marginal Cost - Work papers_Final.xlsx" sheet "SLT". Please explain why Schedule 15 billing hours per month are escalated from 2014 to 2015 while Schedule 91, 92, and 95 billing hours are not escalated from 2014 to 2015.

Response:

The billing hours for Schedules 91, 92, and 95 are an estimate which has remained constant since 2011. Total billing hours for these lighting Schedules equal 166.2 hours, and are based on the billing hours tracked for department 439. To calculate Schedule 15 billing hours, the Schedules 91, 92 and 95 estimate of 71 hours is subtracted from the 166.2 hour total, resulting in 96 billing hours for Schedule 15. Therefore, billing hours for Schedule 15 are higher in 2015 because the numerator in this calculation increased slightly. The Schedule 15 billing hours were not escalated.

March 21, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 170
Dated March 12, 2014

Request:

Please refer to UE 283/PGE/200 Nguyen-Dammen/3. Please provide the model specifications and data used to estimate the price elasticities calculated in September 2013.

Response:

Please see Attachments 170-A through 170-G for the requested information.

Attachment 170-A shows the final calculated elasticities used in the price adjustment model.

Attachment 170-B is the EViews work file and contains the price regression model specifications and the data used to estimate those regressions. Attachment 170-B is confidential and subject to Protective Order No. 14-043.

Attachment 170-C displays the regression model specification output in pdf format. Attachment 170-C is confidential and subject to Protective Order No. 14-043.

Attachment 170-D is the SAS price elasticity model where current price and 10% price change are applied. Attachment 170-D is confidential and subject to Protective Order No. 14-043.

Attachment 170-E contains the model tables from the current price/no price change price elasticity model run.

Attachment 170-F contains he model tables from a 10% price change price elasticity model run.

Attachment 170-G displays SAS output of the current price and price change. The same information in Excel format is provided in Attachment 170-A.

PGE Price Elasticity
Change in kWh With Rise in Price
SSEP13

Million kWh

Group	Current Price Forecast SSEP13_ PRICE_CUR	10% Increase in price Forecast SSEP13_ PRICE_UP10	Change CUR TO UP10	Elasticity CUR TO UP1
SF Heat	1,744.6	1,716.2	(28.4)	(0.163)
SF Non-Heat	3,792.5	3,763.0	(29.5)	(0.078)
MF Heat	1,475.9	1,457.1	(18.8)	(0.127)
MF Non-Heat	492.6	490.8	(1.8)	(0.036)
MH Heat	434.0	431.6	(2.4)	(0.055)
MH Non-Heat	40.5	40.4	(0.1)	(0.019)
Other	51.9	51.9	-	0.000
E14R	5.1	5.1	-	0.000
Residential	8,037.0	7,956.2	(80.8)	(0.101)
Res UPC	8,032	7,951	(80.8)	(0.101)
Secondary Voltage	7,710.5	7,681.9	(28.6)	(0.037)
Primary Voltage	3,762.8	3,756.8	(6.0)	(0.016)
Transmission Voltage	535.9	535.9	-	0.000
Street lighting	103.2	103.2	-	0.000
Total Non-Res	12,112.4	12,077.8	(34.6)	(0.029)
Total Energy	20,149.4	20,034.0	(115.4)	(0.057)
ECFS	495.9	490.1	(5.8)	(0.117)
ECGE	1,027.8	1,025.9	(1.9)	(0.018)
ECHE	737.5	737.5	-	0.000
ECLD	115.1	114.0	(1.0)	(0.090)
ECMC	685.2	685.2	-	0.000
ECMS	348.4	347.9	(0.5)	(0.015)
ECOF	1,073.0	1,071.0	(2.0)	(0.019)
ECOS	871.5	871.5	-	0.000
ECOT	784.6	782.2	(2.4)	(0.031)
ECRT	487.4	486.4	(1.0)	(0.021)
ECTU	675.4	673.9	(1.5)	(0.022)
COMMERCIAL	7,301.7	7,285.5	(16.2)	(0.022)
EMFD	227.5	223.2	(4.3)	(0.190)
EMHT	2,358.4	2,358.4	-	0.000
EMLB	105.7	102.1	(3.6)	(0.339)
EMME	523.5	518.7	(4.8)	(0.092)
EMOM	793.1	789.8	(3.3)	(0.043)
EMPP	412.5	411.3	(1.2)	(0.029)
EMTE	184.3	183.1	(1.2)	(0.066)
MANUFACTURING	4,605.0	4,586.5	(18.5)	(0.040)

UE 283 PGE Response to OPUC 170 Attachment B

This response is an unprintable database file. Staff is not including the response as part of Exhibit Staff/302. If Staff's load forecast issues are not resolved in settlement Staff will include these data in Staff Rebuttal Testimony. Staff will work with PGE to determine an appropriate method to distribute these data to all Parties.

UE 283 PGE Response to OPUC 170 Attachment C

Due to its voluminous nature Staff is not including the response as part of Exhibit Staff/302. If Staff's load forecast issues are not resolved in settlement Staff will include these data in Staff Rebuttal Testimony. Staff will work with PGE to determine an appropriate method to distribute these data to all Parties.

UE 283 PGE Response to OPUC 170 Attachment D

Due to its voluminous nature Staff is not including the response as part of Exhibit Staff/302. If Staff's load forecast issues are not resolved in settlement Staff will include these data in Staff Rebuttal Testimony. Staff will work with PGE to determine an appropriate method to distribute these data to all Parties.

UE 283 PGE Response to OPUC 170 Attachment E

Due to its voluminous nature Staff is not including the response as part of Exhibit Staff/302. If Staff's load forecast issues are not resolved in settlement Staff will include these data in Staff Rebuttal Testimony. Staff will work with PGE to determine an appropriate method to distribute these data to all Parties.

UE 283 PGE Response to OPUC 170 Attachment F

Due to its voluminous nature Staff is not including the response as part of Exhibit Staff/302. If Staff's load forecast issues are not resolved in settlement Staff will include these data in Staff Rebuttal Testimony. Staff will work with PGE to determine an appropriate method to distribute these data to all Parties.

UE 283 PGE Response to OPUC 170 Attachment G

Due to its voluminous nature Staff is not including the response as part of Exhibit Staff/302. If Staff's load forecast issues are not resolved in settlement Staff will include these data in Staff Rebuttal Testimony. Staff will work with PGE to determine an appropriate method to distribute these data to all Parties.

March 26, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 173
Dated March 12, 2014

Request:

Please refer to UE 283/PGE/200 Nguyen-Dammen/14. Please describe each out of sample test referenced at line 6. Include a description of the test, the alternate model specifications, and the results. If available, please provide all documentation of such tests. Please provide all files in their original editable format. Please provide all spreadsheets with reference cells and formulae intact.

Response:

The out-of-sample prediction and testing was performed using the EViews "Forecast" procedure. This procedure produces the following statistics, which measure the fit of the forecasted values:

- Root Mean Square Error
- Mean Absolute Error
- Mean Absolute Percent Error
- Theil Inequality Coefficient (Theil U statistic) including its decomposition:
    - Bias Proportion
    - Variance Proportion
    - Covariance Proportion

EViews Forecast procedure allows the user to specify the forecast period and uses the actual values of the explanatory variables to predict the dependent variable. The out-of-sample was typically defined as the most recent full two years plus the current-year (2013) observations, for a total of 34 observations in our case.

Please see Attachment 174-A for examples of the out-of-sampling statistics and how they were used for selection of model specifications.

Evaluating predictive power of models via out-of-sample predictive "accuracy" statistics predicates on the stability of the forecast environment. While out-of-sample statistics can provide additional indication of the forecasting performance of a model specification, out-of-sample fit is an imperfect approach to model selection on its own due to data revisions. Economic data such as payroll employment undergo "benchmarking" each year. This can substantially revise the prior two years of economic data used to estimate the models, or in the case of out-of-sample testing, revise the data that are used to predict the out-of-sample period. Changes in the economic data, such as the new definition of US GDP present a further challenge to backcasting and testing the accuracy of the original economic data. This is one of the main reasons why PGE frequently re-estimates the load regression models.

All regression analysis, testing and model specification was performed in the EViews work file "sdec13.wfl" with only the final model specifications saved. PGE previously submitted this file with PGE Exhibit 200 work papers.

March 26, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 174
Dated March 12, 2014

Request:

Please refer to UE 283/PGE/200 Nguyen-Dammen/6 at lines 10 through 15. Please describe the process used to select step, spike and trend variables used in the model specifications. Please provide documentation for the selection of these variables. Please provide all files in their original editable format. Please provide all spreadsheets with reference cells and formulae intact.

Response:

PGE used an iterative process of analyzing data series, estimating models, evaluating model results and identifying areas for improvement. First, before any models were re-estimated, we visually inspected the dependent time series to identify possible shifts, trends and outliers. After our graphical inspection, basic regression models were estimated without treatment of outliers followed by an evaluation of model statistics and inspection of the model fit and residuals. At times, outliers could easily be spotted with visual inspection and at other times the outliers were more subtle, requiring inspection of standardized residual graph.

Outliers could result from temporary changes, permanent shifts or simply bad data (from erroneous reads, unexpected events or unreliable estimates). Outliers possibly requiring treatment were identified in the plot of the model residuals. Treatment of outliers, including inclusion of intervention variables "step", "spike," and "trend" variables, typically improves the in-sample fit of the model. Hence PGE also employed out-of-sample testing to assess whether treatment of outliers improved model's predictive capability.

As PGE states in the referenced testimony, "while the theoretical framework and structure of our load forecast model remains essentially unchanged, we did take into account several of Public Utility Commission of Oregon Staff's suggestions made during the load forecast workshops stipulated in UE 262. These changes include re-estimation of the load forecast regression model with attention to the treatment of data outliers and updating the price elasticity equations." OPUC Staff's suggestion of more parsimonious models, i.e., limiting or reviewing the treatment of outliers, was also considered in the model selection, though there is an inherent tradeoff between in-sample fit, out-of-sample fit and parsimony.

Attachment 174-A shows the EViews output (including coefficients and related statistics, out-of-sample performance statistics and standardized residuals graph) of several "use per single-family non-heat customer" model specifications as an example of this process.

The four models shown are:

A) Model without intervention variables;
B) Model for identifying outliers for treatment;
C) Final Model specification used in UE-283; and
D) UE-262 Model, i.e., one with additional intervention variables.

Model D performed the best both in-sample and out-of-sample "accuracy" statistics (lowest "error" and lowest Theil Inequality Coefficient, specifically the Bias component) and Model A (with no intervention variables) performed the worst. Model C (UE 283) came in second. We selected Model C for UE-283 based on the principle of parsimony (i.e., limiting the treatment of outliers) along with the standard fit statistics as suggested by Staff during one the UE 262 load workshops.

All regression analysis, testing and model specification was performed in the EViews work file "sdec13.wfl" submitted with PGE Exhibit 200 work papers.

Example of Alternative Model Selection with Out-of-Sample Statistics

A: Model with No Interventions

upvsfnh c temp_sq*winter temp_sq*spring temp*swing temp*summer winter spring swing jan cld65 wind*(winter+spring) pdl(unemp_or(-1),2,2,3) ar(1) ar(12)

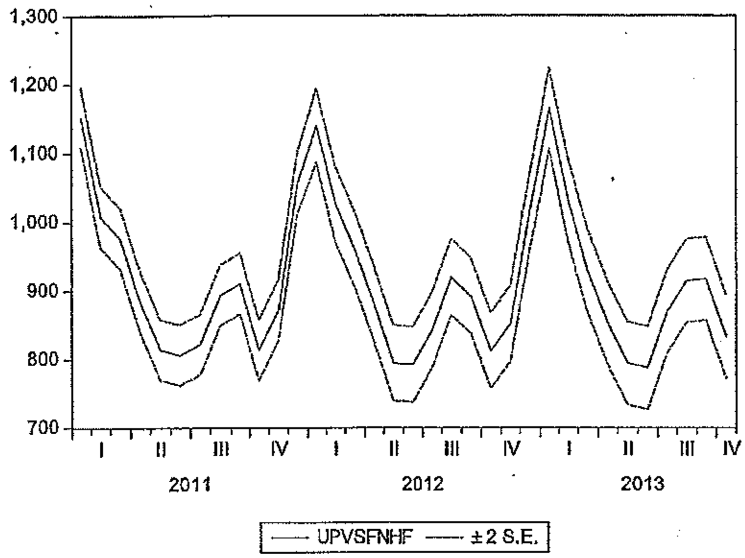
Dependent Variable: UPVSFNH
Method: Least Squares
Date: 03/20/14 Time: 17:11
Sample: 1985M01 2013M10
Included observations: 346
Convergence achieved after 20 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1291.552	206.7366	6.247331	0.0000
TEMP_SQ*WINTER	-143.5802	10.00186	-14.35535	0.0000
TEMP_SQ*SPRING	-161.1651	13.13366	-12.27115	0.0000
TEMP*SWING	-7.159829	1.156295	-6.192045	0.0000
TEMP*SUMMER	-7.648439	3.258000	-2.347588	0.0195
WINTER	658.1303	216.8680	3.034704	0.0026
SPRING	724.6667	226.2747	3.202598	0.0015
SWING	-57.35059	178.5345	-0.321230	0.7482
JAN	84.67458	11.70616	7.233334	0.0000
CLD65	0.876633	0.133269	6.577912	0.0000
WIND*(WINTER+SPRING)	4.754736	1.100143	4.321927	0.0000
PDL01	-0.682566	0.473859	-1.440441	0.1507
AR(1)	0.199369	0.038151	5.225806	0.0000
AR(12)	0.701980	0.036618	19.17039	0.0000

R-squared	0.963834	Mean dependent var	931.9236
Adjusted R-squared	0.962418	S.D. dependent var	111.7531
S.E. of regression	21.66455	Akaike info criterion	9.028852
Sum squared resid	155825.1	Schwarz criterion	9.184489
Log likelihood	-1547.991	Hannan-Quinn criter.	9.090827
F-statistic	680.6099	Durbin-Watson stat	1.537303
Prob(F-statistic)	0.000000		

Inverted AR Roots	.99	.86-.48i	.86+.48i	.50-.84i
	.50+.84i	.02+.97i	.02-.97i	-.47+.84i
	-.47-.84i	-.83+.48i	-.83-.48i	-.96

Lag Distribution of UNEMP_OR(-1)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.51192	0.35539	-1.44044
* . |	1	-0.68257	0.47386	-1.44044
* . |	2	-0.51192	0.35539	-1.44044
	Sum of Lags	-1.70642	1.18465	-1.44044



Forecast: UPVSFNHF	
Actual: UPVSFNH	
Forecast sample: 2011M01 2013M10	
Included observations: 34	
Root Mean Squared Error	24.69967
Mean Absolute Error	19.54147
Mean Abs. Percent Error	2.229856
Theil Inequality Coefficient	0.013547
Bias Proportion	0.327627
Variance Proportion	0.026723
Covariance Proportion	0.645650

B: Model for Identifying Outliers for Treatment

upvsfnh c temp_sq*winter temp_sq*spring temp*swing temp*summer winter spring swing jan cld65 wind*(winter+spring) trend*summer step0101*trend*(winter+spring) step0102-step0205 step1003 step1203 pdl(unemp_or(-1),2,2,3) ar(1) ar(12)

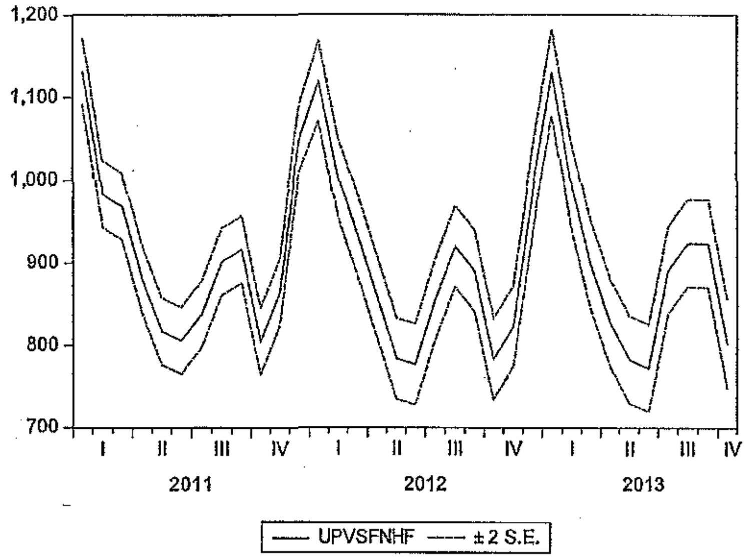
Dependent Variable: UPVSFNH
Method: Least Squares
Date: 03/20/14 Time: 17:10
Sample: 1985M01 2013M10
Included observations: 346
Convergence achieved after 23 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-7225.842	2007.522	-3.599384	0.0004
TEMP_SQ*WINTER	-141.5541	9.424203	-15.02027	0.0000
TEMP_SQ*SPRING	-160.6900	12.26512	-13.10138	0.0000
TEMP*SWING	-7.220816	1.082071	-6.673145	0.0000
TEMP*SUMMER	-8.421322	3.076841	-2.737003	0.0065
WINTER	9194.221	2009.061	4.576378	0.0000
SPRING	9270.537	2009.276	4.613870	0.0000
SWING	8478.050	2008.865	4.220319	0.0000
JAN	85.35616	10.40829	8.200783	0.0000
CLD65	0.881220	0.125797	7.005077	0.0000
WIND*(WINTER+SPRING)	4.858121	1.030348	4.715030	0.0000
TREND*SUMMER	4.289039	1.004265	4.270826	0.0000
STEP0101*TREND*(WINTER+SPRING)	-0.016638	0.004576	-3.635922	0.0003
STEP0102-STEP0205	-15.68718	5.759386	-2.723759	0.0068
STEP1003	-24.19396	7.049565	-3.431979	0.0007
STEP1203	-15.15852	7.120289	-2.128919	0.0340
PDL01	-0.712865	0.443199	-1.608453	0.1087
AR(1)	0.175830	0.043180	4.072027	0.0001
AR(12)	0.660408	0.039708	16.63175	0.0000

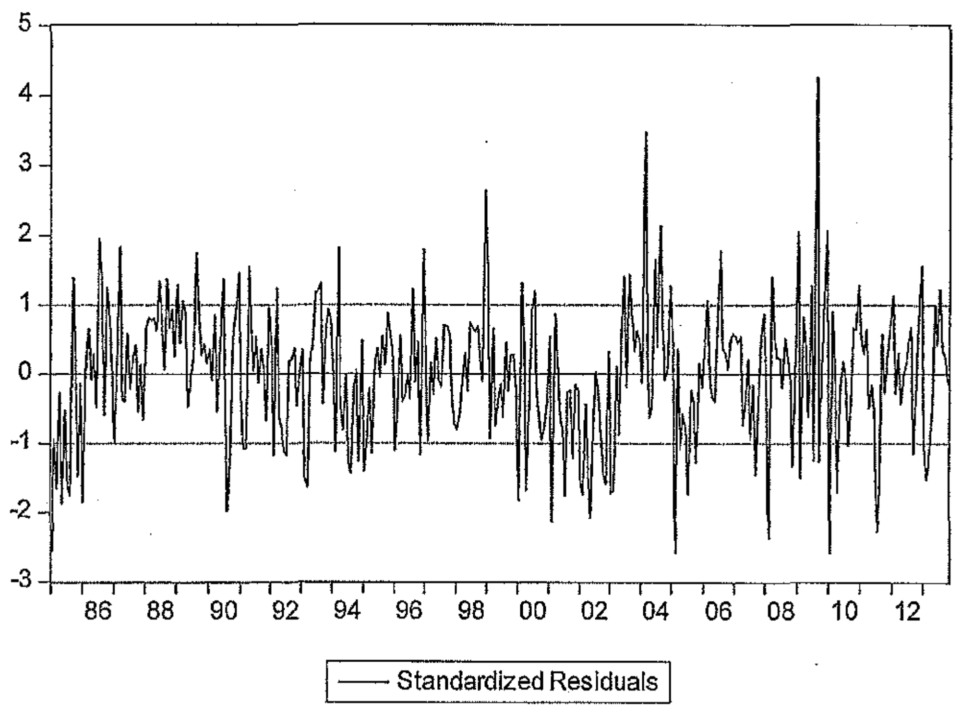
R-squared	0.969733	Mean dependent var	931.9236
Adjusted R-squared	0.968067	S.D. dependent var	111.7531
S.E. of regression	19.97008	Akaike info criterion	8.879695
Sum squared resid	130408.9	Schwarz criterion	9.090916
Log likelihood	-1517.187	Hannan-Quinn criter.	8.963804
F-statistic	582.0477	Durbin-Watson stat	1.737142
Prob(F-statistic)	0.000000		

Inverted AR Roots	.98	.85+.48i	.85-.48i	.50-.84i
	.50+.84i	.01+.96i	.01-.96i	-.47+.84i
	-.47-.84i	-.82+.48i	-.82-.48i	-.95

Lag Distribution of UNEMP_OR(-1)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.53465	0.33240	-1.60845
* . |	1	-0.71287	0.44320	-1.60845
* . |	2	-0.53465	0.33240	-1.60845
Sum of Lags		-1.78216	1.10800	-1.60845



Forecast: UPVSFNHF	
Actual: UPVSFNH	
Forecast sample: 2011M01 2013M10	
Included observations: 34	
Root Mean Squared Error	18.99960
Mean Absolute Error	15.20545
Mean Abs. Percent Error	1.700396
Theil Inequality Coefficient	0.010489
Bias Proportion	0.020350
Variance Proportion	0.206521
Covariance Proportion	0.773129



C: Final Model Specification Submitted in UE-283

upvsfnh c temp_sq*winter temp_sq*spring temp*swing temp*summer winter spring swing jan cld65 wind*(winter+spring) trend*summer step0101*trend*(winter+spring) step0102-step0205 step1003 step1203 spik0402 spik0908 spik1107 pdl(unemp_or(-1),2,2,3) ar(1) ar(12)

Dependent Variable: UPVSFNH
Method: Least Squares
Date: 12/11/13 Time: 19:13
Sample: 1985M01 2013M10
Included observations: 346
Convergence achieved after 25 iterations

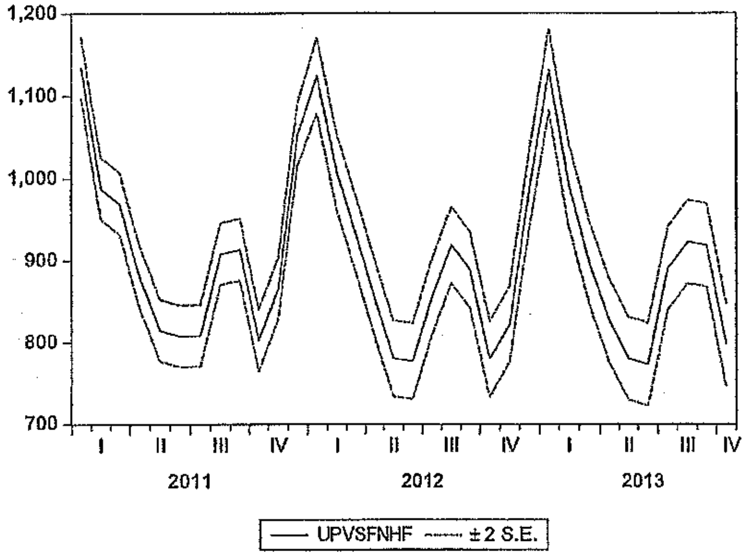
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-7802.839	2079.044	-3.753089	0.0002
TEMP_SQ*WINTER	-139.2661	8.664553	-16.07309	0.0000
TEMP_SQ*SPRING	-158.2239	11.42325	-13.85105	0.0000
TEMP*SWING	-6.224381	1.031121	-6.036520	0.0000
TEMP*SUMMER	-5.507330	2.906747	-1.894671	0.0590
WINTER	9763.093	2080.147	4.693464	0.0000
SPRING	9837.417	2080.207	4.729057	0.0000
SWING	9004.747	2079.946	4.329317	0.0000
JAN	87.45227	10.64624	8.214380	0.0000
CLD65	0.684009	0.121472	5.630979	0.0000
WIND*(WINTER+SPRING)	4.473618	0.946515	4.726410	0.0000
TREND*SUMMER	4.492600	1.039579	4.321558	0.0000
STEP0101*TREND*(WINTER+SPRING)	-0.016448	0.004377	-3.757980	0.0002
STEP0102-STEP0205	-15.31332	5.259575	-2.911513	0.0038
STEP1003	-19.24632	6.585090	-2.922712	0.0037
STEP1203	-18.75684	6.654422	-2.818703	0.0051
SPIK0402	72.21986	15.29621	4.721424	0.0000
SPIK0908	86.59486	16.69770	5.186035	0.0000
SPIK1107	-37.31251	15.60697	-2.390760	0.0174
PDL01	-1.079111	0.410581	-2.628254	0.0090
AR(1)	0.164879	0.041182	4.003630	0.0001
AR(12)	0.694138	0.037688	18.41789	0.0000

R-squared	0.973964	Mean dependent var	931.9236
Adjusted R-squared	0.972277	S.D. dependent var	111.7531
S.E. of regression	18.60728	Akaike info criterion	8.746456
Sum squared resid	112178.8	Schwarz criterion	8.991027
Log likelihood	-1491.137	Hannan-Quinn criter.	8.843845
F-statistic	577.1600	Durbin-Watson stat	1.679401
Prob(F-statistic)	0.000000		

Inverted AR Roots	.98	.85+.48i	.85-.48i	.50-.84i
	.50+.84i	.01+.97i	.01-.97i	-.47+.84i
	-.47-.84i	-.83+.48i	-.83-.48i	-.96

Lag Distribution of UNEMP_OR(-1)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.80933	0.30794	-2.62825
* . |	1	-1.07911	0.41058	-2.62825

*	. |	2	-0.80933	0.30794	-2.62825
		Sum of Lags	-2.69778	1.02645	-2.62825



Forecast: UPVSFNHF	
Actual: UPVSFNH	
Forecast sample: 2011M01 2013M10	
Included observations: 34	
Root Mean Squared Error	17.11159
Mean Absolute Error	13.26145
Mean Abs. Percent Error	1.476574
Theil Inequality Coefficient	0.009451
Bias Proportion	0.010370
Variance Proportion	0.143318
Covariance Proportion	0.846312

D: Previous Model with Several Intervention Variables

upvsfnh c temp_sq*winter temp_sq*spring temp*swing temp*summer winter spring swing jan cld65 wind*(winter+spring) trend*summer step0101*trend*(winter+spring) step0102-step0205 spik9812 spik0402 spik0408 spik0908 spik1001 spik1004 spik1107 step1003 spik1108 step1203 spik1209 spik1301+spik1302+spik1303 pdl(unemp_or(-1),2,2,3) ar(1) ar(12)

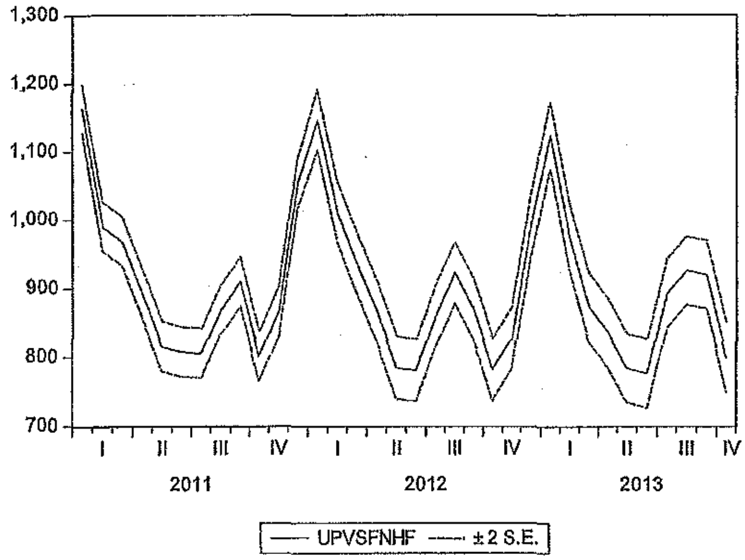
Dependent Variable: UPVSFNH
Method: Least Squares
Date: 03/20/14 Time: 17:16
Sample: 1985M01 2013M10
Included observations: 346
Convergence achieved after 22 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-8224.586	2235.686	-3.678775	0.0003
TEMP_SQ*WINTER	-140.5353	8.186875	-17.16593	0.0000
TEMP_SQ*SPRING	-155.9859	10.95376	-14.24039	0.0000
TEMP*SWING	-6.185484	0.989006	-6.254243	0.0000
TEMP*SUMMER	-5.316294	2.761601	-1.925077	0.0551
WINTER	10192.33	2236.273	4.557732	0.0000
SPRING	10242.35	2236.156	4.580335	0.0000
SWING	9421.976	2236.122	4.213533	0.0000
JAN	90.89352	11.26194	8.070859	0.0000
CLD65	0.636790	0.115703	5.503639	0.0000
WIND*(WINTER+SPRING)	4.394544	0.898513	4.890905	0.0000
TREND*SUMMER	4.697788	1.117612	4.203417	0.0000
STEP0101*TREND*(WINTER+SPRING)	-0.016202	0.004277	-3.788507	0.0002
STEP0102-STEP0205	-15.37997	4.936678	-3.115450	0.0020
SPIK9812	35.02807	14.30178	2.449211	0.0149
SPIK0402	72.98016	14.41222	5.063769	0.0000
SPIK0408	34.02445	14.36479	2.368601	0.0185
SPIK0908	89.27916	15.80954	5.647169	0.0000
SPIK1001	-41.00308	14.61761	-2.805047	0.0053
SPIK1004	-18.75370	14.59333	-1.285087	0.1997
SPIK1107	-41.36210	14.96023	-2.764805	0.0060
STEP1003	-21.37044	6.455288	-3.310532	0.0010
SPIK1108	-42.51776	14.87656	-2.858037	0.0045
STEP1203	-14.69821	7.015611	-2.095071	0.0370
SPIK1209	-22.39571	14.63552	-1.530229	0.1270
SPIK1301+SPIK1302+SPIK1303	-28.93081	12.49873	-2.314699	0.0213
PDL01	-0.930572	0.386854	-2.405486	0.0167
AR(1)	0.153816	0.039274	3.916523	0.0001
AR(12)	0.728703	0.036097	20.18749	0.0000

R-squared	0.976701	Mean dependent var	931.9236
Adjusted R-squared	0.974643	S.D. dependent var	111.7531
S.E. of regression	17.79549	Akaike info criterion	8.675860
Sum squared resid	100387.4	Schwarz criterion	8.998250
Log likelihood	-1471.924	Hannan-Quinn criter.	8.804237
F-statistic	474.5939	Durbin-Watson stat	1.654586
Prob(F-statistic)	0.000000		

Inverted AR Roots	.99	.86-.49i	.86+.49i	.50-.84i
	.50+.84i	.01+.97i	.01-.97i	-.47-.84i
	-.47+.84i	-.83+.49i	-.83-.49i	-.96

Lag Distribution of UNEMP_OR(-1)	i	Coefficient	Std. Error	t-Statistic
* . |	0	-0.69793	0.29014	-2.40549
* . |	1	-0.93057	0.38685	-2.40549
* . |	2	-0.69793	0.29014	-2.40549
	Sum of Lags	-2.32643	0.96714	-2.40549



Forecast: UPVSFNHF
Actual: UPVSFNH
Forecast sample: 2011M01 2013M10
Included observations: 34

Root Mean Squared Error	14.15879
Mean Absolute Error	11.43486
Mean Abs. Percent Error	1.283329
Theil Inequality Coefficient	0.007816
Bias Proportion	0.027514
Variance Proportion	0.087151
Covariance Proportion	0.885335

March 25, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 184
Dated March 12, 2014

Request:

Please provide summary data for each work order involving Line Extensions as defined by PGE Rule I. Provide the following data for work orders completed from January 1, 2011 to December 31, 2013:

Work Order Number	Total cost of work order	Customer Estimate for Line Extension	Amount billed to customer	Amount capitalized to rate base	Amount expensed	Customer rate schedule	Year	New or Existing Service

Response:

PGE objects to this request on the basis of undue burden. PGE does not keep records of historical line extension costs in the manner specifically requested. Subject to and without waiving its objection, PGE responds as follows:

Attachment 184-A contains historical 2011-2013 line extension jobs for the following customer categories: single-family residential, residential development-driven, multi-family residential and commercial development.

The data includes the following for each line extension: Work Order No., line extension cost, the applicable line extension allowance, customer cost responsibility, and the amount capitalized to rate base.

PGE Response to OPUC Data Request 184 Attachment A

Due to the voluminous nature of this response Staff is not including the response as part of Exhibit Staff/302. If Staff's line extension issues are not resolved in settlement Staff will include this Data in Staff Rebuttal Testimony.

March 25, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 197
Dated March 12, 2014

Request:

Please describe how PGE identifies when customers are eligible for a refund under sections 4 and 8 of Rule I. What portion of customers who are eligible for a refund received a refund between January 1, 2009 and December 31, 2013?

Response:

Generally, the applicant notifies PGE when they believe they are eligible for a refund in accordance with the sections of Rule I specified above. Although PGE does not maintain a specific database for this type of activity, the incidence of refunds is quite low, below 10%.

March 25, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 199
Dated March 12, 2014

Request:

Please provide all customer complaints related to Line Extensions or Rule I received by PGE from January 1, 2009 through current.

Response:

PGE's Customer Complaint database covering the period of January 1, 2009 to current shows 11 associated complaint cases regarding Line Extensions. The years in which these complaint cases were received are as follows:

2009 - Four associated cases
2010 - Four associated cases, 1 inquiry
2011 - Zero associated cases
2012 - Zero associated cases
2013 - Two associated cases

Attachment 199-A provides each of the above-mentioned cases or inquiry as recorded, with no At-Fault violation assessed in any case.

Attachment 199-A is confidential and subject to Protective Order No. 14-043.

Pages Kaufman/31-39 are confidential.

You must have signed the Protective Order in this docket in order to view this page.

April 22, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 361
Dated April 8, 2014

Request:

Please refer to PGE response to UE 283 OPUC DR 155. For 2012, please provide the following data:

- **a. The number of net metering customers by rate schedule;**
- **b. The capacity of net metering generation by rate schedule; and**
- **c. The annual kWh of net metering customers by rate schedule.**

Response:

Please refer to the following table for cumulative end of year 2012 net metering data:

Rate	# of Customers	Capacity (kW)	Annual Net Consumption (kWh)
7	2,645	10,190	22,062,852
32	142	3,001	4,677,266
38	1	18	152,880
47	2	43	17,217
83	121	7,107	47,130,146
85	22	2,298	15,940,884
89	9	1,245	14,608,800
Total	2,942	23,902	104,590,045

April 22, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 362
Dated April 8, 2014

Request:

Please refer to PGE response to UE 283 OPUC DR 155. For 2012, please provide the following data:

- **a. The number of solar feed in tariff customers by rate schedule;**
- **b. The capacity of solar feed in tariff generation by rate schedule; and**
- **c. The annual kWh sales to solar feed in tariff customers by rate schedule.**

Response:

Please refer to the following table for cumulative end of year 2012 solar feed in tariff data:

Rate	# of Customers	Capacity (kW)	Annual Sales (kWh)
7	570	3,990	6,016,779
32	49	419	1,527,597
47	2	19	24,626
83	25	2,740	12,316,080
85	15	1,010	13,401,601
89	2	507	1,825,139
Total	682	8,685	35,111,822

April 30, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 362 (Revised)
Dated April 8, 2014

Request:

Please refer to PGE response to UE 283 OPUC DR 155. For 2012, please provide the following data:

a. The number of solar feed in tariff customers by rate schedule;
b. The capacity of solar feed in tariff generation by rate schedule; and
c. The annual kWh sales to solar feed in tariff customers by rate schedule.

Response (Dated: April 22, 2014):

Please refer to the following table for cumulative end of year 2012 solar feed in tariff data:

Rate	# of Customers	Capacity (kW)	Annual Sales (kWh)
7	570	3,990	6,016,779
32	49	419	1,527,597
47	2	19	24,626
83	25	2,740	12,316,080
85	15	1,010	13,401,601
89	2	507	1,825,139
Total	682	8,685	35,111,822

First Revised Response (Dated: April 30, 2014):

PGE is modifying this response to correct the miscounted number of customers on rate schedules 7, 32, 83, and 85 in 2012. Please refer to the following table for the revised counts:

Rate	# of Customers	Capacity (kW)	Annual Sales (kWh)
7	573	3,990	6,016,779
32	46	419	1,527,597
47	2	19	24,626
83	50	2,740	12,316,080
85	9	1,010	13,401,601
89	2	507	1,825,139
Total	682	8,685	35,111,822

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April 22, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 368
Dated April 8, 2014

Request:

Please refer to PGE response to UE 283 OPUC DR 159.

a. **Please provide the postage rates for PGE in 2012, 2013, 2014 and 2015.**
b. **Please identify the incentives provided by PGE to encourage paperless billing and electronic delivery of other mailings.**
c. **Please provide the number of pieces of mail sent by PGE annually between 2004 and 2013.**
d. **Please provide the number of customers using paperless billing in 2012 by rate schedule.**

Response:

a. Attachment 368-A provides postage rates, mail counts, and paperless bill counts. The 2015 budget for Printing and Automated Mail Services (Department 727) is based on PGE's current 2014 postage rate expense escalated for 2015.
b. PGE currently promotes paperless billing in newsletter communications, on bill envelopes, and in e-newsletters. Current incentives focus on benefits to the customer of paper waste reduction and ease of use. PGE continues to encourage new signups through call center and website promotions. E-mail and direct mail sweepstakes are also scheduled for this fall.
c. See Attachment 368-A.
d. Paperless bill counts are provided on a monthly basis for 2012. We do not have customer counts by rate schedule for paperless bills in 2012.

	PAPER CUSTOMER BILLING STATEMENTS						CUSTOMER NOTICES & CREDIT LETTERS				
Level of Sortation	5-Digit IMB	3-Digit IMB	AADC IMB	Mixed ADC IMB	5-Digit Auto	Full Rate	5-Digit Auto	3-Digit Auto	AADC Auto	Mixed ADC Auto	Full Rate
2012 January*	0.337	0.362	0.365	0.387	0.340	0.465	0.340	0.365	0.368	0.390	
February	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
March	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
April	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
May	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
June	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
July	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
August	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	0.450
September	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	0.450
October	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	0.450
November	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	0.450
December	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	0.450
2013 January*	0.347	0.371	0.371	0.401	0.350		0.350	0.374	0.374	0.404	
February	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
March	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
April	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
May	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
June	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
July	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
August	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
September	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
October	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
November	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
December	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
2014 January*	0.357	0.381	0.381	0.402	0.360		0.360	0.384	0.384	0.405	
February	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
March	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
April	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
May	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
June	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
July	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
August	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
September	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
October	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
November	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	
December	0.378	0.403	0.403	0.432	0.381		0.381	0.406	0.406	0.435	

2015 Postage rates are not available. Postage rates for 2014 are escalated and used to estimate 2015 budget expense.

*Note: Postage rate increase occurs in month of January.

Postage rate depends on level of sortation. PGE processes addresses through postal sortation software, which allows PGE to receive postage discounts with the USPS.

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Paper Bills, Notices, and Letters	10,467,985	10,475,883	10,887,659	10,871,365	10,946,903	11,086,753	10,929,385	10,872,156	10,638,644	10,372,409

	January	February	March	April	May	June	July	August	September	October	November	December
2012 Paperless Bills	109,407	110,772	112,506	113,417	113,827	114,318	114,861	114,956	115,047	116,104	116,896	117,156

April 28, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 397
Dated April 14, 2014

Request:

Please refer to PGE response to UE 283 OPUC DR 184. Please provide the work orders and customer quotes for the WR No. in the attached file "UE 283 PGE OPUC DR 397 Attach A.xlsx":

Response:

The quotes provided to customers are represented in confidential Attachment 397-A. PGE bills customers for line extension costs, when applicable, from estimated costs rather than from actual costs.

Please see Attachment 397-A for the requested work orders. This attachment is confidential and subject to the provisions of OPUC Protective Order 14-043. Attachment 397-A is provided to Staff on CD only because it contains customer-specific data. If other parties wish to see this data, please contact Rob MacFarlane at 503-464-8954.

April 25, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 402
Dated April 14, 2014

Request:

Does PGE notify customers when they are eligible for refunds under Rule I? If not, please explain how customers can identify when they are eligible for a refund.

Response:

PGE field personnel attempt to determine if a pre-existing line extension is relatively new when they receive a request for new service from a customer. If PGE can verify that the prior line extension is less than five years old, it attempts to notify the original customer or applicant for whom the line extension was constructed.

April 25, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 403
Dated April 14, 2014

Request:

Please describe the process that PGE uses to provide prospective customers with line extension quotes. Please identify when quotes are consideredfirm commitments and when the company may deviate from the customer's line extension quote.

Response:

Generally, PGE is notified by the prospective customer/applicant that they wish to connect to PGE's system. PGE arranges a meeting with the customer/applicant to determine their electrical requirements. PGE then develops a cost estimate and shares this cost estimate with the customer. The cost estimate specifies the total cost, the line extension allowance, and the customer contribution, if applicable. PGE considers the quotes as firm when the customer/applicant signs the line extension agreement.

February 18, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 113
Dated February 18, 2014

Request:

Please provide by rate class for each of the most recently completed 20 calendar years, in electronic spreadsheet format:

a. Number of customers on a year-end basis;
b. Number of customers on an annual average basis; and
c. Class annual sales volumes.

Response:

Attachment 113-A contains the number of customers on a year-end basis; number of customers on an annual average basis; and the class (actual) annual sales volumes in MWh for the years 1994 to 2013.

Year-End (December) Customer Counts by Customer Class: 1994-2013

Year	Month	Residential	Secondary	Transmission	Primary	Lighting	Total
1994	12	557338	77072	7	175	680	635272
1995	12	570253	78828	7	180	687	649955
1996	12	585722	80897	7	190	694	667510
1997	12	603039	81011	7	193	702	684952
1998	12	619504	83584	7	208	654	703957
1999	12	632858	85410	7	207	658	719140
2000	12	637339	86820	7	220	641	725027
2001	12	647318	87568	7	255	654	735802
2002	12	653074	89894	8	248	249	743473
2003	12	663257	90277	9	237	248	754028
2004	12	674426	92144	9	242	244	767065
2005	12	685568	93766	9	248	246	779837
2006	12	696779	95484	10	249	250	792772
2007	12	706444	96838	10	246	250	803788
2008	12	712554	97142	10	247	244	810197
2009	12	715458	99762	10	260	249	815739
2010	12	719031	101138	10	250	247	820676
2011	12	721216	101698	9	246	244	823413
2012	12	725502	102348	9	249	246	828354
2013	12	732341	103228	8	252	241	836070

Customer Classes are as follows
Class 1: Residential Service
Class 3: General Service/Secondary Voltage
Class 4: Large Industrial-Transmission Voltage
Class 5: Primary Voltage
Class 6: Lighting--Streetlight, traffic light

Staff/302
Kaufman/52

Annual Average Customer Count By Customer Class: 1994-2013

year	Residential	Secondary	Transmission	Primary	Lighting	Total
1994	551,420	76,292	7	174	679	628,571
1995	563,514	77,927	7	176	686	642,310
1996	578,254	79,751	7	186	692	658,889
1997	595,683	80,651	7	191	696	677,229
1998	610,952	82,420	7	197	684	694,260
1999	626,539	84,492	7	201	656	711,895
2000	636,449	86,461	7	213	654	723,783
2001	642,708	87,207	7	235	645	730,802
2002	649,145	90,673	7	253	514	740,593
2003	658,232	91,761	9	246	248	750,495
2004	668,830	93,008	9	243	247	762,336
2005	680,093	94,940	9	245	246	775,533
2006	691,931	96,631	9	249	249	789,069
2007	701,952	98,124	10	250	251	800,587
2008	710,991	99,814	10	253	248	811,316
2009	714,377	100,966	10	261	248	815,861
2010	717,719	102,033	10	255	249	820,266
2011	720,056	102,695	10	244	244	823,249
2012	723,440	103,513	9	249	246	827,456
2013	728,481	104,131	8	255	245	833,120

Customer Classes are as follows
- Class 1: Residential Service
- Class 3: General Service/Secondary Voltage
- Class 4: Large Industrial-Transmission Voltage
- Class 5: Primary Voltage
- Class 6: Lighting--Streetlight, traffic light

Annual Average Sales Volume By Customer Class (MWhs)

Year	Residential	Secondary	Transmission	Primary	Lighting	Total
1994	6,767,441	6,132,816	2,087,417	1,779,530	99,516	16,866,721
1995	6,848,200	6,312,179	2,164,177	1,894,128	101,224	17,319,908
1996	6,970,701	6,458,959	1,884,610	2,020,064	101,779	17,436,113
1997	7,173,512	6,875,845	2,051,840	2,195,856	99,081	18,396,134
1998	7,348,792	7,105,394	2,051,199	2,328,728	100,387	18,934,500
1999	7,495,428	7,284,593	2,066,512	2,388,617	104,140	19,339,291
2000	7,397,755	7,406,367	2,390,680	2,509,271	101,735	19,805,808
2001	7,118,052	7,185,520	2,079,563	2,608,575	105,337	19,097,047
2002	7,062,905	6,972,487	1,935,085	2,655,429	99,902	18,725,807
2003	7,201,244	7,042,180	1,514,066	2,677,711	101,407	18,536,608
2004	7,440,246	7,290,472	1,177,609	2,675,511	101,711	18,685,549
2005	7,387,717	7,387,328	1,252,507	2,729,988	104,309	18,861,849
2006	7,567,830	7,609,045	1,298,975	2,785,605	105,066	19,366,521
2007	7,619,012	7,682,584	1,380,648	2,755,930	107,615	19,545,789
2008	7,691,454	7,648,988	1,447,098	2,808,708	109,883	19,706,131
2009	7,746,763	7,432,015	1,019,350	2,856,170	110,655	19,164,954
2010	7,555,050	7,264,243	937,617	3,025,778	110,250	18,892,939
2011	7,572,220	7,290,626	1,126,337	3,038,362	110,515	19,138,060
2012	7,600,402	7,301,271	1,102,333	3,133,334	110,697	19,248,037
2013	7,607,868	7,281,249	1,073,064	3,194,083	108,816	19,265,079

Customer Classes are as follows
- Class 1: Residential Service
- Class 3: General Service/Secondary Voltage
- Class 4: Large Industrial-Transmission Voltage
- Class 5: Primary Voltage
- Class 6: Lighting--Streetlight, traffic light

CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

<u>REDACTED</u>
June 11, 2014

These pages are confidential.

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CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 304

Exhibits in Support
Of Opening Testimony

<u>REDACTED</u>
June 11, 2014

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CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 305

Exhibits in Support
Of Opening Testimony

June 11, 2014

Docket No. UE 262 Forecast and Actuals (Weather Adjusted)

Year	Residential	Secondary	Transmission	Primary	Lighting	Total
2013*	7,607,868	7,281,249	1,073,064	3,194,083	108,816	19,265,079
SDEC12E**	7,587,700	7,405,300	531,700	3,272,300	111,500	18,908,700
	-0.27%	1.68%	-101.82%	2.39%	2.41%	-1.88%

*2013 actual weather adjusted sales from UE 283 PGE Response to OPUC DR 113 Attachement A.
**2013 forecast from UE 262 PGE/1300 Workpapers

CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 306

Exhibits in Support
Of Opening Testimony

June 11, 2014

Staff Price Adjustment Forecast (including Energy Efficiency)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Change Used in Elasticity Adjustment*	**Change in 2014 Rates****		**Sales Forecast MWh in 1000s**	**Required Revenue Requirement Reduction*****	**Base Reveue Under Current Rates**	**Difference Between Staff and PGE Revenue**
		Base	**Total**				
(a)	0%	-0.9%	-2.4%	19731	$106,000,000	$1,751,705,140LK	$23,441,302
(b)	2%	0.9%	-1.1%	19706	$78,000,000	$1,749,383,568LK	$21,119,730
(c)	4%	2.6%	0.7%	19682	$48,000,000	$1,747,061,996LK	$18,798,158
(d)	7.5%	5.6%	3.5%	19639	$0	$1,742,999,244LK	$14,735,406
(e)	11%	8.7%	6.6%	19597	($51,000,000)	$1,738,936,493LK	$10,672,655
(f)	11%	6.4%	4.6%	19484	$0	$1,728,263,838****	$0

*Relative to 2013 rates, inclusive of PW2, Tucannon, and miscelaneous schedules
**Relative to current prices, inclusive of PW2 and Tucannon
***Revenue reduction that equates to given price change percent
****PGE forecasted revenue as filed

CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 307

Exhibits in Support
Of Opening Testimony

<u>REDACTED</u>
June 11, 2014

	2014 CPI	Exigent Rate Change	2015 CPI	2015 Postage Rate	Monthly Mail	Monthly Postage costs
January	1.016	1.043	1	0.378	836107	$ 316,048
February	1.016	1.043	1.017351	0.385	836107	$ 321,532
March	1.016	1.043	1.017351	0.385	836107	$ 321,532
April	1.016	1.043	1.017351	0.385	836107	$ 321,532
May	1.016	1.043	1.017351	0.385	836107	$ 321,532
June	1.016	1.043	1.017351	0.385	836107	$ 321,532
July	1.016	1	1.017351	0.369	836107	$ 308,528
August	1.016	1	1.017351	0.369	836107	$ 308,528
September	1.016	1	1.017351	0.369	836107	$ 308,528
October	1.016	1	1.017351	0.369	836107	$ 308,528
November	1.016	1	1.017351	0.369	836107	$ 308,528
December	1.016	1	1.017351	0.369	836107	$ 308,528
Annual					10033281	$ 3,774,876

Total 2015 Postage Expense **$ 3,774,876**

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CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 308

Exhibits in Support Of Opening Testimony

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June 11, 2014

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CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 309

Exhibits in Support Of Opening Testimony

June 11, 2014

Rate	(1) Net Metering		(2) Solar Feed In		(3) Direct Access		(4) Allocation	(5)
	Count	Share	Count	Share	Count	Share	PGE	Staff
7	2645	90%	573	84%		0%	**0%**	**58%**
32	142	5%	46	7%	47	16%	**16%**	**9%**
38	1	0%		0%		0%	**0%**	**0%**
47	2	0%	2	0%		0%	**0%**	**0%**
83	121	4%	50	7%	83	29%	**29%**	**14%**
85	22	1%	9	1%	117	41%	**41%**	**14%**
89	9	0%	2	0%	38	13%	**13%**	**5%**
Total	2942	100%	682	100%	285	100%	**100%**	**100%**

CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 310

Exhibits in Support
Of Opening Testimony

June 11, 2014

STAFF REVISED PORTLAND GENERAL ELECTRIC
2015 MARGINAL COST STUDY
SUMMARY OF CUSTOMER SERVICE MARGINAL COSTS

SCHEDULE	DESCRIPTION	ANNUAL METERING EXPENSES	ANNUAL BILLING EXPENSES	ANNUAL OTHER EXPENSES	TOTAL CUSTOMER EXPENSES
Schedule 7	Residential	$0.35	$25.30	$9.18	$34.83
Schedule 15	Residential - Area Lights	$0.00	$23.94	$5.92	$29.86
Schedule 15	Commercial - Area Lights	$0.00	$20.73	$5.76	$26.49
Schedule 32	Small Non-Residential (< 30 KW)	$0.55	$20.58	$9.81	$30.94
Schedule 38	Large Non-Residential Time of Use	$7.05	$27.30	$14.06	$48.40
Schedule 47	Small Irrigation	$0.48	$18.73	$6.57	$25.77
Schedule 49	Large Irrigation	$0.94	$24.27	$6.59	$31.80
Schedule 83	Large Non-Residential (31-200 KW)	$3.92	$41.08	$34.37	$79.38
Schedule 85	Large Non-Residential (201-1,000 KW)	$9.95	$102.77	$345.60	$458.31
Schedule 85	Large Non-Residential (> 1,000 - 4,000 KW	$6.79	$98.93	$1,545.53	$1,651.24
Schedule 89	Large Non-Residential (> 4,000 KW)	$0.22	$381.04	$13,749.13	$14,130.39
Schedule 90	Large Non-Residential	$0.00	$9.45	$45,301.32	$45,310.77
Schedule 91	Street and Highway Lighting	$0.00	$179.58	$100.93	$280.51
Schedule 92	Traffic Sign. & Comm. Dev.	$0.00	$179.58	$47.02	$226.60

PORTLAND GENERAL ELECTRIC
2015 MARGINAL COST STUDY
SUMMARY OF CUSTOMER SERVICE MARGINAL COSTS

SCHEDULE	DESCRIPTION	ANNUAL METERING EXPENSES	ANNUAL BILLING EXPENSES	ANNUAL OTHER EXPENSES	TOTAL CUSTOMER EXPENSES
Schedule 7	Residential	$0.35	$24.45	$9.18	$33.98
Schedule 15	Residential - Area Lights	$0.00	$24.27	$5.92	$30.19
Schedule 15	Commercial - Area Lights	$0.00	$21.94	$5.76	$27.69
Schedule 32	Small Non-Residential (< 30 KW)	$0.55	$23.04	$9.81	$33.41
Schedule 38	Large Non-Residential Time of Use	$7.05	$27.07	$14.06	$48.18
Schedule 47	Small Irrigation	$0.48	$19.59	$6.57	$26.64
Schedule 49	Large Irrigation	$0.94	$25.45	$6.59	$32.99
Schedule 83	Large Non-Residential (31-200 KW)	$3.92	$56.74	$34.37	$95.03
Schedule 85	Large Non-Residential (201-1,000 KW)	$9.95	$241.20	$345.60	$596.74
Schedule 85	Large Non-Residential (> 1,000 - 4,000 KW)	$6.79	$225.85	$1,545.53	$1,778.17
Schedule 89	Large Non-Residential (> 4,000 KW)	$0.20	$192.37	$16,904.35	$17,096.92
Schedule 90	Large Non-Residential	$0.20	$192.37	$16,904.35	$17,096.92
Schedule 91	Street and Highway Lighting	$0.00	$178.60	$100.93	$279.53
Schedule 92	Traffic Sign. & Comm. Dev.	$0.00	$178.60	$47.02	$225.62

STAFF REVISED PORTLAND GENERAL ELECTRIC
2015 MARGINAL COST STUDY
RELATIVE SIZE OF CUSTOMER SERVICE MARGINAL COSTS

SCHEDULE	DESCRIPTION	ANNUAL METERING EXPENSES	ANNUAL BILLING EXPENSES	ANNUAL OTHER EXPENSES	TOTAL CUSTOMER EXPENSES
Schedule 7	Residential	100%	103%	100%	103%
Schedule 15	Residential - Area Lights	N/A	99%	100%	99%
Schedule 15	Commercial - Area Lights	N/A	95%	100%	96%
Schedule 32	Small Non-Residential (< 30 KW)	100%	89%	100%	93%
Schedule 38	Large Non-Residential Time of Use	100%	101%	100%	100%
Schedule 47	Small Irrigation	100%	96%	100%	97%
Schedule 49	Large Irrigation	100%	95%	100%	96%
Schedule 83	Large Non-Residential (31-200 KW)	100%	72%	100%	84%
Schedule 85	Large Non-Residential (201-1,000 KW)	100%	43%	100%	77%
Schedule 85	Large Non-Residential (> 1,000 - 4,000 KW	100%	44%	100%	93%
Schedule 89	Large Non-Residential (> 4,000 KW)	111%	198%	81%	83%
Schedule 90	Large Non-Residential	0%	5%	268%	265%
Schedule 91	Street and Highway Lighting	N/A	101%	100%	100%
Schedule 92	Traffic Sign. & Comm. Dev.	N/A	101%	100%	100%

CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 311

Exhibits in Support
Of Opening Testimony

June 11, 2014

TABLE 6
Staff Customer Marginal Cost Adjustment to PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS WITH PORT WESTWARD 2 AND TUCANNON
2015

CATEGORY	RATE SCHEDULE	Forecast SDEC13E15 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	740,049	7,462,740	$865,667,667	$911,076,948	$45,409,281	5.2%
Employee Discount				($901,500)	($949,692)	($48,192)	
Subtotal				$864,766,167	$910,127,255	$45,361,089	5.2%
Outdoor Area Lighting	15	0	15,972	$3,720,554	$3,745,841	$25,287	0.7%
General Service <30 kW	32	89,471	1,556,500	$172,367,833	$179,377,804	$7,009,971	4.1%
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,796,145	$6,183,878	$387,733	6.7%
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,936,637	$3,371,205	$434,567	14.8%
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,634,170	$8,855,043	$1,220,872	16.0%
General Service 31-200 kW	83	10,953	2,735,660	$248,856,924	$259,838,170	$10,981,246	4.4%
General Service 201-4,000 kW							
Secondary	85-S	1,239	2,431,372	$196,724,916	$205,327,916	$8,603,000	4.4%
Primary	85-P	192	645,752	$48,174,223	$51,027,649	$2,853,426	5.9%
Schedule 89 > 4 MW							
Primary	89-P	18	913,928	$58,653,931	$61,992,754	$3,338,823	5.7%
Subtransmission	89-T	5	209,810	$14,329,190	$14,925,464	$596,274	4.2%
Schedule 90	90-P	4	1,453,535	$88,554,928	$93,367,119	$4,812,191	5.4%
Street & Highway Lighting	91/95	205	97,094	$18,143,668	$18,524,415	$380,747	2.1%
Traffic Signals	92	17	3,327	$265,561	$276,074	$10,513	4.0%
COS TOTALS		847,034	17,656,462	$1,730,924,847	$1,816,940,588	$86,015,741	5.0%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	436,001	$11,089,832	$9,593,728	($1,496,104)	
Primary	485-P	41	220,953	$5,535,287	$4,859,917	($675,370)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,864	$549,126	$506,454	($42,673)	
Primary	489-P	9	506,343	$7,589,496	$6,319,081	($1,270,415)	
Subtransmission	489-T	3	333,091	$3,993,810	$3,014,995	($978,815)	
DIRECT ACCESS TOTALS		214	1,511,253	$28,757,552	$24,294,175	($4,463,377)	
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,759,682,399	$1,841,234,763	$81,552,364	4.6%

TABLE 6
PORTLAND GENERAL ELECTRIC
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS WITH PORT WESTWARD 2 AND TUCANNON
2015

CATEGORY	RATE SCHEDULE	Forecast SDEC13E15 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	740,049	7,462,740	$865,667,667	$909,285,890	$43,618,223	5.0%
Employee Discount				($901,500)	($947,746)	($46,245)	
Subtotal				$864,766,167	$908,338,144	$43,571,977	5.0%
Outdoor Area Lighting	15	0	15,972	$3,720,554	$3,746,640	$26,086	0.7%
General Service <30 kW	32	89,471	1,556,500	$172,367,833	$179,984,699	$7,616,866	4.4%
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,796,145	$6,183,442	$387,297	6.7%
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,936,637	$3,371,386	$434,749	14.8%
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,634,170	$8,855,043	$1,220,872	16.0%
General Service 31-200 kW	83	10,953	2,735,660	$248,856,924	$260,330,589	$11,473,665	4.6%
General Service 201-4,000 kW							
Secondary	85-S	1,239	2,431,372	$196,724,916	$205,847,878	$9,122,962	4.6%
Primary	85-P	192	645,752	$48,174,223	$51,101,085	$2,926,861	6.1%
Schedule 89 > 4 MW							
Primary	89-P	18	913,928	$58,653,931	$62,243,675	$3,589,744	6.1%
Subtransmission	89-T	5	209,810	$14,329,190	$15,075,593	$746,404	5.2%
Schedule 90	90-P	4	1,453,535	$88,554,928	$92,682,302	$4,127,374	4.7%
Street & Highway Lighting	91/95	205	97,094	$18,143,668	$18,529,270	$385,602	2.1%
Traffic Signals	92	17	3,327	$265,561	$276,041	$10,480	3.9%
COS TOTALS		847,034	17,656,462	$1,730,924,847	$1,816,565,787	$85,640,940	4.9%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	436,001	$11,089,832	$9,660,047	($1,429,785)	
Primary	485-P	41	220,953	$5,535,287	$4,874,490	($660,797)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,864	$549,126	$521,325	($27,802)	
Primary	489-P	9	506,343	$7,589,496	$6,456,978	($1,132,518)	
Subtransmission	489-T	3	333,091	$3,993,810	$3,095,411	($898,399)	
DIRECT ACCESS TOTALS		214	1,511,253	$28,757,552	$24,608,250	($4,149,301)	
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,759,682,399	$1,841,174,037	$81,491,639	4.6%

CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 312

Exhibits in Support
Of Opening Testimony

June 11, 2014

Example of line extension customer charge and refund calculations

All numbers are illustrative only

Line		First customer	Second customer
(a)	New Facility Cost	$ 10,000	$ 2,000
(b)	Share of previous extension cost	$ -	$ 3,000
(c)	Sub total	$ 10,000	$ 5,000
(d)	Line Extension Allowance	$ 1,600	$ 1,600
(e)	Initial Customer Charge	$ 8,400	$ 3,400
(f)	Refund	$ 3,000	
(g)	Total cost of both extensions	$ 12,000	
(h)	Total Company Responsibility	$ 3,200	
(i)	Total Customer Responsibility	$ 8,800	

Line Explanation

(a) Total cost of new facilities added as a result of line extension

(b) New customer's cost responsibility of preexisting line extension. Equal to refund on line (f)

(c) Total cost of line extension request = (a)+(b)

(d) Line Extension Allowance as currently calculated

(e) Customer charge=(c)-(d)

(f) Staff proposes no change to the current method for calculating refund amounts

(g) Total cost is sum of line (a) for each customer.

(h) Total Company responsibility is sum of line (d) for each customer.

(i) Total customer responsibility=(g)-(h)

CASE: UE 283
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 313

Exhibits in Support
Of Opening Testimony

June 11, 2014

Central Hudson Gas & Electric Corporation

Staff/313
Kaufman1

Reactive Demand

A phase-in of charges for reactive demand for certain Central Hudson customers will occur between May 1, 2010 and October 1, 2011.

What is the reactive demand provision?

This provision requires that a customer be billed for the highest 15-minute integrated kVA of lagging reactive demand established during the month less 1/3 of the highest 15-minute kW demand during that month. In simpler terms, a customer is billed for having a ***power factor*** that is less than 95% at the rate of $0.83/RkVA.

What is power factor?

Power factor is the relationship of the energy being supplied to a piece of equipment (real power) compared to the energy being effectively used by the piece of equipment (apparent power).

An analogy with an inclined plane is useful to demonstrate the difference between total energy supplied (kVA) and real or useful energy (kW). In the analogy, a group of individuals (kVA) have to push a large ball from one side of an inclined plane to another. The active power (kW) needed to accomplish this is the same as if the plane were flat, but one or more individuals is required to keep the ball up on the path, preventing it from rolling down the plane. The result is a loss of capacity, since these individuals cannot be used for rolling, and additional friction losses, since these individuals need to touch the ball.

Power factor is calculated as kW / kVA. For example, if a small plant has a measured demand of 900 kW for a given month and the kVA delivered by the Company was 1,000 kVA, the customer's power factor would be 900/1000 = .9 or 90%.

Why is Central Hudson billing for reactive demand?

Provisions to charge for reactive demand are being implemented in order to reduce lost energy on our transmission and distribution system. Customers with poor power factors take up capacity (room) on our lines. To compensate for this loss of capacity, Central Hudson must install capacitors and/or increase the size of our facilities.

Who is subject to reactive demand charges?

Beginning May 1, 2010, Service Classification Nos. 3 & 13 customers will see an increased power factor requirement from 90% to 95% in order to avoid reactive demand charges.

Beginning August 1, 2010, Service Classification No. 2 (and Service Classification No. 14 customers whose parent service classification is 2) with demand greater than 1,000 kW in two of the preceding 12 months become subject to RkVA provisions.

Beginning October 1, 2010, Service Classification No. 10 customers with induction generators having a total nameplate rating greater than 1,000 kW become subject to RkVA provisions.

Beginning October 1, 2011, Service Classification No. 10 customers with induction generators having a total nameplate rating greater than 500 kW and Service Classification Nos. 2 and 14 customers with demand greater than 500 kW in two of the preceding 12 months become subject to RkVA provisions.

Can I view my reactive demand?

Yes. If you are subject to the reactive demand provisions, you are provided with access to Central Hudson's Energy Manager software. Your hourly kW and kVAR can be viewed through this software. If your phone line and meter are installed and you have not yet received your login information, please contact your Central Hudson representative or email: EnergyManager@cenhud.com.

How can I perform calculations related to reactive power?

1. Find your highest hourly kW for the month ______ (A)
2. Find your highest hourly kVAR for the month ______(B)
3. Billed (excess) RkVA* = B – (A/3)
   **multiply this by $0.83/RkVA to estimate billed charges*
4. Total RkVA = $(A^2 + B^2)^{1/2}$ = ______ (C)
5. Power Factor = A / C

Can I avoid these charges?

You may be able to avoid or reduce the reactive power charges applicable to your account by installing on-site equipment, such as capacitors, to improve your power factor.

GENERAL RULES

10. Meter Reading and Billing - Continued

10.11 Reactive Power Demand Charge - Continued

(1) – Continued

(b) New Customers, beginning with the Customer's first bill for service, if the maximum demand during the first year of service is expected in the Company's estimate to equal or exceed:

(i) 1,000 kW in any two months commencing between October 1, 2010 and September 30, 2011; or

(ii) 500 kW in any two months commencing on or after October 1, 2011;

(c) Customers who are successors of Customers referred to in subparagraphs (a) and (b) above, beginning with the successor Customer's first bill for service, unless the maximum demand in the Company's estimate is not expected to exceed 300 kW in any month during the first year of service;

(d) Customers with induction-generation equipment who would not otherwise be subject to the Reactive Power Demand Charge pursuant to subparagraphs (a) through (c) above:

(i) beginning with bills having a "from" date on or after October 1, 2010, if the equipment has a nameplate rating equal to or greater than 1,000 kW; and

(ii) beginning with bills having a "from" date on or after October 1, 2011, if the equipment has a nameplate rating equal to or greater than 500 kW; and

(e) Any Customer with induction-generation equipment not covered under subparagraphs (a) through (d), beginning with the first bill for service. The kVar requirements of the equipment will be determined from the nameplate rating of the Customer's generating equipment or from the design specifications of the manufacturer of the generating equipment. The kVar requirements of the Customer's generating equipment will be reduced by the kVar rating of any power factor corrective equipment installed by the Customer.

GENERAL RULES

10. Meter Reading and Billing - Continued

10.11 Reactive Power Demand Charge - Continued

(2) Reactive Power Demand Charges pursuant to paragraph (1)(a)(i) above will commence no later than the Customer's first bill that is issued with a "from" date on or after:

(a) April 1, 2011, for Customers billed under: (i) Rate I or Rate III of SC 8, 9, or 12, (ii) Rate I of SC 5, (iii) SC 11 with a contract demand between 1000 kW and 1500 kW, or (iv) Standby Service rates of SC 5, 8, 9, or 12 if the Customer would otherwise be billed under (i) or (ii) of this paragraph; and

(b) July 1, 2015, for Customers billed under: (i) Rate II of SC 5, 8, 9, or 12, (ii) SC 13, (iii) SC 11 with a contract demand greater than 1500 kW, or (iv) Standby Service rates of SC 5, 8, 9, or 12 if the Customer would otherwise be billed under (i) or (ii) of this paragraph.

Reactive Power Demand Charges pursuant to paragraph (1)(a)(ii) will commence no later than the Customer's first bill that is issued with a "from" date on or after October 1, 2012.

Reactive Power Demand Charges pursuant to paragraph (1)(a)(iii) will commence no later than the Customer's first bill issued with a "from" date on or after October 1 of the following year.

(3) If the Company is advised by the telecommunications carrier that access was denied to make the communications service operational or if the Company was unable to install a Var meter because the Company was denied access to the Customer's premises, billing will commence the later of: (A) the Customer's first bill that is issued with a "from" date on or after January 1, 2011, if the Customer is subject to Reactive Power Demand Charges pursuant to (1)(a)(i), or October 1 of the applicable year if the Customer is subject to Reactive Power Demand Charges pursuant to paragraph (1)(a)(ii) or (1)(a)(iii); or (B) the first bill issued with a "from" date six months after the Company was notified by the telecommunications carrier that access was denied or six months after the Company was denied access to install the Var meter, as applicable.

GENERAL RULES

10. Meter Reading and Billing - Continued

10.11 Reactive Power Demand Charge - Continued

(4) Charge per kVar

$1.41 per kVar applicable to Customers specified in paragraph (1)(a), (b), (c), or (d) above for billable reactive power demand. Billable reactive power demand, in kVar, shall be equal to the kVar at the time of the kW maximum demand (as defined in General Rule 10.4) during the billing period (all hours, all days) less one-third of such kW maximum demand; provided, however, that, if this difference is less than zero, the billable reactive power demand shall be zero. If the same kW maximum demand occurs two or more times during the billing period, the reactive power demand will be determined at the time of the first kW maximum demand occurrence.

If the Company restricts an existing Customer with synchronous generation from utilizing Customer load power factor correction through the Generator's controls, the Customer will not be subject to the above charge until such time that the Company removes this restriction.

$1.41 per kVar applicable to Customers specified in paragraph (1)(e) above for the kVar requirements of the induction-generation equipment

(5) A Customer subject to the Reactive Power Demand Charge pursuant to paragraph (1)(a), (b), or (c) above will no longer be subject to the Reactive Power Demand Charge commencing in the month following 12 consecutive months in which the maximum demand does not exceed 300 kW.

(6) After the installation of telecommunications service by the telecommunications carrier, the Company will make available to a Customer its kVar and kW interval data via the Internet. Existing Customers subject to the Reactive Power Demand Charge in October 2011 pursuant to paragraph (1)(a)(ii) above will generally be provided access to daily kW and kVar interval data during each of the twelve months in advance of being subject to the Reactive Power Demand Charge. Existing Customers subject to the Reactive Power Demand Charge in January 2011, October 2012, and each October thereafter pursuant to paragraphs (1)(a)(i) and (1)(a)(iii) above will generally be provided access to daily kVar and kW interval data during each of the six months in advance of being subject to the Reactive Power Demand Charge. Customer access to daily kW and kVar interval data via the Internet will generally be provided on a one-day lag, subject to the Company resolving telecommunications issues that may arise from time to time.

PACIFIC POWER
A DIVISION OF PACIFICORP

Available

In all territory served by the Company in the State of Oregon.

Applicable

To Large Nonresidential Consumers whose entire electric service requirements are supplied hereunder and whose loads have not registered more than 200 kW, more than six times in the preceding 12-month period and as specified in the Company's Rules & Regulations, Rule 7.J. Deliveries at more than one point, or more than one voltage and phase classification, will be separately metered and billed. Service for intermittent, partial requirements, or highly fluctuating loads, or where service is seasonally disconnected during any one-year period will be provided only by special contract for such service.

Monthly Billing

The Monthly Billing shall be the sum of the Distribution Charge and Transmission & Ancillary Services Charge plus the applicable rate in Schedule 80 and applicable adjustments as specified in Schedule 90.

	Delivery Voltage	
	Secondary	**Primary**
Distribution Charge		
Basic Charge		
Load Size ≤50 kW, per month	$ 18.00	$ 24.00
Load Size 51-100 kW, per month	$ 34.00	$ 41.00
Load Size 101 - 300 kW, per month	$ 81.00	$ 96.00
Load Size > 300 kW, per month	$115.00	$137.00
Load Size Charge		
≤50 kW, per kW Load Size	$ 1.15	$ 1.35
51 - 100 kW, per kW Load Size	$ 0.90	$ 1.10
101 – 300 kW, per kW Load Size	$ 0.55	$ 0.65
> 300 kW, per kW Load Size	$ 0.35	$ 0.35
Demand Charge, per kW	$ 3.88	$ 4.70
Distribution Energy Charge, per kWh	0.393¢	0.068¢
Reactive Power Charge, per kvar	$ 0.65	$ 0.60
Transmission & Ancillary Services Charge		
Per kW	$ 1.49	$ 1.21
System Usage Charge		
Schedule 200 Related, per kWh	0.075¢	0.069¢
T&A and Schedule 201 Related, per kWh	0.078¢	0.072¢

kW Load Size:

For determination of the Basic Charge and the Load Size Charge, the kW load size shall be the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month.

Minimum Charge

The minimum monthly charge shall be the Basic Charge and the Load Size Charge plus the demand charge. A higher minimum may be required under contract to cover special conditions.

Reactive Power Charge

The maximum 15-minute reactive demand for the month in kilovolt-amperes in excess of 40% of the measured kilowatt demand for the same month.

Demand

The kW shown by or computed from the readings of the Company's demand meter for the 15-minute period of the Consumer's greatest use during the month, determined to the nearest kW, but not less than 15 kW.

Metering Adjustment

For a Consumer receiving service at secondary delivery voltage where metering is at primary delivery shall have all billing quantities multiplied by an adjustment factor of 0.9718.

For a Consumer receiving service at primary delivery voltage where metering is at secondary delivery voltage shall have all billing quantities multiplied by an adjustment factor of 1.0290.

Supply Service Options

All Consumers taking Delivery Service under this schedule shall pay the applicable rates in Schedule 200, Base Supply Service. Additionally, each Consumer shall specify Supply Service Schedule 201 or Schedule 220, as appropriate and in accordance with the Applicable section of the specified rate schedule. If Consumer elects to receive Supply Service from an ESS, Delivery Service shall be provided under Schedule 728, Direct Access Delivery Service.

Franchise Fees

Franchise fees related to Schedule 200, Base Supply Service, are collected through the System Usage Charge - Schedule 200 Related rate. Franchise fees related to Transmission & Ancillary Services and franchise fees related to Schedule 201, Net Power Costs, are collected through the System Usage Charge - T&A and Schedule 201 Related rate. Franchise fees related to distribution charges are collected through distribution charges.

Special Conditions

The Consumer shall not resell electric service received from the Company under provisions of this Schedule to any person, except by permission of the Company or as otherwise expressly provided in Company tariffs.

Continuing Service

Except as specifically provided otherwise, the rates of this tariff are based on continuing service at each service location. Disconnect and reconnect transactions shall not operate to relieve a seasonal Consumer from minimum monthly charges.

Term of Contract

The Company may require the Consumer to sign a written contract which shall have a term of not less than one year.

Rules and Regulations

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

CASE: UE 283
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

June 11, 2014

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

A. My name is Brian Bahr. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97302.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe specific adjustments I recommend to the Company's proposed rate increase.

Q. Did you prepare an exhibit for this docket?

A. Yes. In addition to my witness qualification statement, I prepared confidential Exhibit Staff/402, which consists of various documents Staff reviewed in connection with its analysis.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, BENEFITS

Q. Please describe the Company's request regarding medical, dental, vision, and other benefits.

A. The Company has requested approximately $81.9 million in expenses relating to benefits.[1] This cost includes such forms of compensation as long term disability benefits, employee wellness program, and the pension plan. The expense includes costs for both bargaining (union) and non-bargaining (non-union) employees. Benefit plan premiums are typically shared between the Company and the employees. The Company has proposed sharing for its union employees of 90/10 (employees pay 10 percent of premium costs and the Company pays 90 percent) and 85/15 for non-union employees.

The Company offers various plans for medical, dental, and vision benefits. Employees may elect to enroll in one of the plans or waive enrollment. Based on their personal status and elections, employees are classified into the following categories: employee only, employee and spouse, employee and child, or family.

Q. Please describe the analysis performed by Staff.

A. Staff reviewed the Company's responses to 13 Staff data requests as well as the Company's filing and supporting workpapers. For its review, Staff first analyzed the overall historical trend in benefits costs and the Company's forecasted increase in premium amounts. As shown in Table 6 of Exhibit PGE/600, Barnett-Jaramillo/19, the Company expects a net increase in

[1] *See* PGE Workpaper 600 'Total Comp' included as Exhibit Staff 402, Bahr/1.

medical and dental plan premiums from 2013 to 2015. To support its claim that its overall compensation package (including premium increases and sharing percentages) is reasonable, the Company cites a Towers-Watson 2013 Energy Services BENVAL Study. A page of this study was provided to Staff;[2] however, no context was provided for the graphs contained therein, the companies participating in the survey were anonymous, and in general, the page lends basically no credible support to PGE's position.

Consistent with standard practice regarding other expenses Staff reviews, Staff proposes to escalate the Company's 2013 benefits expense by the U.S. Urban Consumers CPI Index, which indicates an escalation factor of 1.4 percent for 2014 and 1.8 percent for 2015.[3] Escalating the known, actual expense eliminates the need to rely on subjective forecasts.

Staff also compared the Company's premium cost sharing to industry averages published in relevant surveys. Staff typically proposes no adjustment to sharing between the Company and bargaining employees unless the sharing percentage is deemed unreasonable upon review. These rates are negotiated between the Company and the union, include a wide range of total compensation elements, and are difficult to adjust without upsetting the carefully negotiated compensation balance. For these reasons, Staff proposes no change to the Company's sharing percentage with bargaining employees of 90/10.

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[2] *See* Company's confidential supplemental response to Staff Data Request No. 275, included as confidential Exhibit Staff/402, Bahr/2-4.
[3] *See* page 41 of http://www.oregon.gov/DAS/OEA/docs/economic/forecast0314.pdf, included as Exhibit Staff/402, Bahr/5.

As stated above, the Company proposes to share premium costs with its non-bargaining employees at a ratio of 85/15. Staff compared this ratio to that found in a 2013 study published by the Kaiser Family Foundation. Staff typically relies on Kaiser Family Foundation research for industry health benefit trends and to date has yet to find a compelling reason to rely more heavily on other evidence. Regarding premium sharing, the survey states:[4]

> *Covered workers contribute on average 18% of the premium for single coverage and 29% of the premium for family coverage, similar to the percentages contributed in 2012 and relatively unchanged over the past decade.*

Staff recommends adjusting the Company's premium sharing for non-bargaining employees from its proposed amount of 85/15 to the industry average for single families of 82/18, as referenced above. Staff is not proposing to adjust the sharing percentage more drastically, which would account for the 71/29 sharing ratio average for the industry, because of a lack of specificity in the study on what constitutes single versus family coverage.

Q. Please describe Staff's proposed adjustment.

A. Staff's adjustment consists of two distinct elements, an adjustment to the sharing of plan premiums and an adjustment to the total cost based on Staff's proposed reduction to FTE. Details of Staff's proposed adjustment are found in confidential Exhibit Staff/402, Bahr/7-10.

[4] *See* The Kaiser Family Foundation Employer Health Benefits 2013 Summary of Findings, included as Exhibit Staff/402, Bahr/6.

To calculate the adjustment related to premium sharing, Staff first obtained from the Company the number of non-union employees by category (employee only, employee and spouse, etc.) for medical, dental, and vision plans and how many employees of each category selected each coverage option (Kaiser, PPO, waive, etc.) in 2013.[5] Staff then obtained the monthly premiums for 2013, again, by employee category and coverage option.[6] By multiplying these amounts and annualizing them, Staff obtained the total 2013 benefits cost per FTE. The cost was escalated using the U.S. Urban Consumers CPI Index, which indicates an escalation factor of 1.4 percent for 2014 and 1.8 percent for 2015.[7] Staff then calculated the difference between a sharing ratio of 85/15 and 82/18, resulting in a downward adjustment to the Company's proposed benefits cost of approximately $0.78 million.

Staff's second adjustment, as noted above, relates to the flow-through effects on medical benefits of Staff's proposed adjustment to the Company's proposed FTE level. To calculate this adjustment, Staff obtained the Company's test year benefits expense by category (group life insurance, pension plan, education plan, etc.).[8] Staff distinguished each category total by whether the expense was dependent on FTE levels. For example, the cost of administering benefits doesn't change based on a change to the total employee level of the

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[5] *See* Company's response to Staff Data Request No. 276, included as Exhibit Staff/402, Bahr/23-24.
[6] *See* Company's confidential response to Staff Data Request No. 275, included as confidential Exhibit Staff/402, Bahr/25-27.
[7] *See* page 41 of http://www.oregon.gov/DAS/OEA/docs/economic/forecast0314.pdf, included as Exhibit Staff/402, Bahr/5.
[8] *See* PGE Workpaper 600 'Total Comp' included as Exhibit Staff 402, Bahr/1.

Company; however, the cost of the health and dental plan would be directly reduced if the Company's employee level were reduced.

Staff divided the total FTE sensitive benefits cost by the number of FTE to obtain the cost per FTE, which is $24,434. This amount would then be multiplied by the number of FTE that is deducted from the Company's general rate filing. The recommended adjustment to FTE is sponsored by Staff witness Marianne Gardner.

Q. Does Staff recommend an adjustment to the Company's proposed medical, dental, and vision benefits costs?

A. Yes. As described above, Staff proposes a two-part adjustment. The first adjustment reflects Staff's proposal to share premium costs for non-union employees at a ratio of 82/18 rather than 85/15. The amount of this adjustment is $783,886. Staff also proposes a flow-through adjustment based on Staff's adjustment to FTE levels in the amount of $24,434 per FTE.

ISSUE 2, PENSION EXPENSE

Q. Please describe the company's request regarding pension costs.

A. The Company's proposed rate increase includes a test year pension expense of approximately $25.2 million, $15.2 million of which is expensed and $10 million of which is capitalized. Additionally, the Company is proposing to include in rate base its estimated prepaid pension asset, which is defined as the difference between the Company's total cash payments into its pension fund and the cumulative accrual expense the Company has incurred, as calculated under Financial Accounting Standard (FAS) 87 and other relevant Generally Accepted Accounting Principles (GAAP). The amount of the Company's estimated prepaid pension asset, net of the estimated $26.4 million of accumulated deferred taxes associated with it, is approximately $49 million.

Q. How are pension costs typically treated by the Commission?

A. Though most expenses approved for inclusion in rates are based on cash costs, cash payments from a company to its pension fund can be volatile from year to year, depending on market and interest rates, as well as changing pension regulations. Because of the volatility of these cash payments, the Commission has approved the use of accrual pension costs as a proxy for cash payments. These accrual pension costs are calculated in accordance with applicable standardized accounting guidance.

The Commission is currently conducting a general investigation into the recovery of pension costs in Docket No. UM 1633. In that docket, the Commission is investigating whether FAS 87 should be continued for use in rate recovery of pension expense, whether a company's prepaid pension asset should be included in rate base, and whether there are more effective methods of pension cost recovery than those currently in practice in Oregon.

Q. How did Staff analyze the Company's requested pension costs?

A. Staff reviewed the Company's responses to 18 Staff data requests related to pension costs as well as the testimony and supporting workpapers included in the Company's filing. In analyzing the Company's requested pension cost, Staff distinguished between the two parts of the proposed cost, the requested FAS 87 expense amount and the inclusion in rate base of the prepaid pension asset.

As described above, the Commission has historically relied on FAS 87 expense as a reasonable representation of cash costs in any given year. The FAS 87 expense amount is calculated and determined by third party actuaries. Though most of the calculation's inputs are based on actual costs and amounts, two of the inputs require a degree of subjective judgment. These are the expected long term market rate of return and the expected discount rate, which must be forecasted by the actuary. Typically, Staff analyzes these two inputs, reviews them for reasonableness, recalculates the expense, and potentially recommends an adjustment to the proposed cost based on recommended changes to the expected rate of return or discount rate.

With regard to the Company's request to include its prepaid pension asset in rate base, Staff notes this request was also made in the Company's previous general rate case, Commission Docket No. UE 262. Several other companies have made the same request in recent general rate cases, including NW Natural (UG 226), PacifiCorp (UE 263), and Avista (UG 246). As these rate cases have been concurrent with UM 1633, the Commission's general investigation into pension cost recovery, Staff has recommended in each case that no change to current cost recovery methods is warranted until the conclusion of the general investigation.

As the balance of a prepaid pension asset grows, so also grows the balance of its associated deferred tax benefit. Staff notes that PGE, as well as the three other utility companies mentioned above, currently does not include its prepaid pension asset in rate base. However, in contrast to the other companies, PGE currently does include the associated deferred tax benefit, which reduces rate base and benefits customers.

Q. Does Staff recommend an adjustment to the Company's proposed FAS 87 expense?

A. No. Staff carefully reviewed the calculations of the third party actuary used by the Company to determine the expected test year FAS 87 expense. Staff also reviewed comparisons between forecasted and actual expense amounts in recent years and found no trend of overstating. Staff also notes that the Company's pension expenses have been tracked closely by Staff through the Commission's general pension investigation and the Company's most recent general rate case.

Q. Does Staff recommend an adjustment to the Company's proposed inclusion in rate base of its prepaid pension asset, net of the associated deferred tax benefit?

A. Yes. Consistent with recent practice and Commission decisions, Staff recommends continuing the Company's current pension cost recovery method until a conclusion is reached in UM 1633. Because that docket is still pending, Staff recommends no change to the Company's current pension cost recovery method. Namely, the prepaid pension asset should not be included in rate base, but the associated deferred tax benefit should continue to be passed on to customers through a rate base reduction.

ISSUE 3, AFUDC

Q. Please explain how the Company accounts for Allowance for Funds Used During Construction (AFUDC).

A. The Company accrues the capital component of AFUDC to Construction Work In Progress (CWIP), FERC Account 107, during the construction phase. When the project has been determined to be used and useful, the AFUDC is reclassified from CWIP to Plant in Service, FERC Account 101. The Company is proposing to include in rate base the AFUDC expected to be in FERC Account 101 as of December 31, 2014, as well as that related to the two capital projects to come online in 2015, Port Westward II (PW2) and Tucannon Wind Farm (Tucannon).

FERC prescribes a specific formula for exactly how AFUDC should be calculated. PGE has permission to perform a slightly different calculation, adjusting the rate on a monthly basis instead of yearly. The overall net effect of this exception is neutral, as it only serves to keep the rate more current. Were the Company to use an incorrect rate to calculate AFUDC, the rate base amount could be misstated.

Q. Please describe Staff's analysis of AFUDC.

A. Staff reviewed the Company's responses to 12 data requests from Staff as well as workpapers provided by the Company in support of its filing. To ensure the Company is calculating its AFUDC correctly, Staff recalculated the Company's 2012 and 2013 AFUDC rates. The result of Staff's calculation was a minimal difference. This difference relates only to the 25 basis point band less than which a true-up isn't necessary according to the rule, and does not indicate an error in the Company's calculation. Staff also reviewed the calculation of AFUDC related to Tucannon and PW2 and scanned the list of capital projects with which AFUDC is associated.

Q. Does Staff recommend an adjustment related to AFUDC?

A. No. As the Company appears to be accurately calculating and accruing AFUDC using the correct rate, Staff has no recommended adjustments relating to this area.

ISSUE 4, AFFILIATED INTERESTS

Q. Please describe the Company's affiliated interests.

A. Business transactions conducted between the Company and any of its affiliated interests must be approved by the Commission, as required under ORS 757.495. As the Company had no new affiliated interest applications come before the Commission since its last rate case, Staff's review focused primarily on the Company's annual affiliated interest report and its actual billings to and from its affiliates.

Filed on May 29, 2014, and docketed as Commission Report No. RE 64, the Company's annual affiliated interest report shows annual billings between PGE and its affiliates as well as the Company's cost allocation manual. Currently, the Company's billings are to and from its two subsidiaries, 121 SW Salmon Corporation and the Salmon Springs Hospitality Group.

Q. Please describe Staff's analysis of the Company's affiliated interests.

A. In addition to reviewing the Company's 2012 and 2013 affiliated interest reports, Staff also reviewed the 2013 non-labor expenses related to the Company's affiliates.

Q. Does Staff recommend an adjustment related to affiliated interests?

A. No. As the Company has no new affiliated interests since its last rate case and the accounting for its current affiliate billings appears correct, Staff has no recommended adjustments relating to this area.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. With regard to the Company's proposed medical benefits expense, Staff proposes two adjustments. The first adjusts non-union medical benefits premium sharing from 85/15 to 82/18, and results in a downward adjustment of $782,886. The second adjusts benefits costs based on Staff's proposed FTE adjustment. The amount of this adjustment is $24,434 per FTE.

With regard to pension costs, Staff recommends no adjustments be made to the Company's requested test year pension expense amount of approximately $25.2 million. The Company's prepaid pension asset, in the amount of approximately $49 million, however, should not be included in rate base. The $26.4 million of tax benefits associated with the prepaid pension asset should continue to be included as a reduction to rate base until the Commission determines otherwise in the general pensions investigation.

Based on Staff's review of AFUDC and affiliated interests, Staff recommends no adjustments be made based on either of these topics at this time.

Table 1. Summary of Adjustments

Amount	**Adjustment**	**Expense or Rate Base**
$0	Pension Expense	N/A
$49,059,989	Remove Prepaid Pension Asset	Rate Base
$782,886	Reduce non-union employee benefits premium sharing from 85/15 to 82/18	Expense
$24,434 per FTE	Reduce benefits to account for Staff's adjustment to FTE	Expense
$0	AFUDC	N/A
$0	Affiliated Interests	N/A

Q. Does this conclude your direct testimony?

A. Yes.

CASE: UE 283
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME:	BRIAN BAHR
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR UTILITY ANALYST
ADDRESS:	3930 FAIRVIEW INDUSTRIAL DR SE, SALEM, OR 97302
EDUCATION:	Certificate of Public Management, Willamette University, Salem OR Bachelor of Science, Accountancy, Brigham Young University, Provo UT
EXPERIENCE:	Employed with the Oregon Public Utility Commission from March 2011 to present, currently serving as Senior Utility Analyst in the Rates, Finance, & Audit Section of the Energy Division. Employed by Modern Seouf Plastics in Alexandria, Egypt as a Managerial Intern from January 2010 to June 2010. Assisted in variety of duties including supervision of production facilities and staff, market analysis, budget forecasting, sales, and office administration. Employed by PricewaterhouseCoopers LLP in New York City as a Financial Assurance Associate from October 2007 to November 2009. Performed audits of various financial institutions, including investment banks, hedge funds, and insurance companies. Employed by TESRA, SA in Antofagasta, Chile as a Project Management Assistant from September 2005 to April 2006. Assisted in design process and implementation of rail road crossing and other civil engineering projects.

CASE: UE 283
WITNESS: BRIAN BAHR

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 402

Exhibits in Support Of Opening Testimony

REDACTED

June 11, 2014

INFORMATION CONTAINED IN STAFF EXHIBIT 402

PAGES 4, 9, 10 AND 27 ARE CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 14-043. YOU

MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 283 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

Total Compensation Summary ($000)

Incentive Compensation		2011 Actual	2012 Actual	2013 (9+3)	2014 FOM
Boardman (PGE share)		112	120	151	136
Coyote Springs (PGE Share)		302	408	210	160
Port Westward		461	443	410	241
Pelton PIC (PGE Share)		7	10	13	10
Biglow		25	29	34	21
PGE PIC		4,978	4,498	4,736	3,723
Total PIC		**5,884**	**5,509**	**5,554**	**4,291**
Boardman ACI (PGE share)		45	45	20	28
Pelton ACI		21	14	17	11
~~Wholesale Marketing~~		~~1,342~~	~~1,200~~	~~1,206~~	~~693~~
PGE ACI		2,726	2,304	2,358	1,378
Officer ACI		1,867	1,637	600	1,071
Total ACI		**6,000**	**5,200**	**4,201**	**3,180**
PGE Stock Incentives		1,546	1,796	1,845	988
Officer Stock Incentives		2,408	2,473	2,508	-
Total Stock Incentive Plan		**3,954**	**4,269**	**4,353**	**988**
Notable Achievement Awards		325	409	569	129
Miscellaneous Awards		69	39	24	-
Total Notables & Misc.		**393**	**448**	**593**	**129**
Total Incentives		**16,232**	**15,426**	**14,702**	**8,588**
Wages & Salaries	a	**204,586**	**208,924**	**160,131**	**223,449**
Benefit Compensation					
Health & Dental Plan		36,387	37,098	36,907	39,298
Employee Wellness Program		356	220	297	301
Health Reimbursement Account		1,436	3,997	1,693	1,708
Short Term Disability Insurance		464	474	478	511
Long Term Disability Benefits		1,666	1,181	1,527	2,133
Group Life Insurance		1,087	1,223	1,232	1,106
Employee Assistance Program		42	54	31	55
Retirement Savings Plan		15,862	15,556	15,506	16,076
Pension Plan		5,417	12,433	19,131	15,457
Education Plan		264	289	409	455
Misc. Employee Benefits		820	1,087	601	273
Benefits Administration		626	668	430	573
Total Benefits		**64,427**	**74,279**	**78,242**	**77,947**
Total Compensation		**285,244**	**298,629**	**253,075**	**309,984**

a 2013 through Q3

May 23, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE *First Supplemental* Response to OPUC Data Request No. 275
Dated March 26, 2014

Request:

For each Medical (Health, Dental, and Vision) plan, please identify the premium amount for 2010, 2011, 2012, and 2013. If the premium amounts vary by labor group, please provide the information for each labor group separately.

Response (dated April 9, 2014):

Attachment 275-A provides a summary of premium amounts for all health, dental, and vision plans for 2010, 2011, 2012 and 2013. Attachment 275-A is confidential and subject to Protective Order No. 14-043.

First Supplemental Response (dated May 23, 2014):

Per a discussion with parties on May 20, 2014, Attachment 275-B provides the 2013 BENVAL survey comparing PGE's non-union medical costs to the market. These survey results display the ranking of PGE's 2013 medical costs as compared to other energy services companies within PGE's revenue size, with adjustments made for socioeconomic and employee demographic differences between the comparison groups. PGE's code in the chart is "BLV."

Attachment 275-B is confidential and subject to Protective Order No. 14-043.

UE 283

Attachment 275-B

Provided in Electronic Format only

Confidential and Subject to Protective Order No. 14-043

2013 BENVAL – Medical Active

This page is confidential.

You must have signed the Protective Order in this docket in order to view this page.

TABLE A.4

Mar 2014 - Other Economic Indicators

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
GDP (Bil of 2009 $),												
Chain Weight (in billions of $)	15,052.4	15,470.7	15,761.3	16,182.8	16,708.5	17,273.6	17,822.7	18,327.7	18,815.3	19,286.6	19,738.2	20,185.4
% Ch	1.8	2.8	1.9	2.7	3.2	3.4	3.2	2.8	2.7	2.5	2.3	2.3
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2009=100	103.2	105.0	106.5	108.2	110.0	111.8	113.7	115.6	117.5	119.5	121.6	123.7
% Ch	2.0	1.7	1.4	1.6	1.7	1.7	1.7	1.7	1.6	1.7	1.7	1.7
Personal Consumption Deflator,												
Chain Weight U.S., 2009=100	104.1	106.0	107.2	108.4	109.9	111.7	113.6	115.7	117.7	119.8	122.0	124.2
% Ch	2.4	1.8	1.1	1.1	1.4	1.6	1.7	1.8	1.7	1.8	1.8	1.8
CPI, Urban Consumers,												
1982-84=100												
Portland-Salem, OR-WA	224.6	229.8	234.0	237.1	240.8	244.9	249.7	254.4	259.3	264.3	269.5	274.7
% Ch	2.9	2.3	1.8	1.3	1.6	1.7	1.9	1.9	1.9	1.9	2.0	1.9
U.S.	224.9	229.6	233.0	236.3	240.4	244.9	249.5	254.6	259.4	264.5	269.9	275.1
% Ch	3.1	2.1	1.5	1.4	1.8	1.8	1.9	2.0	1.9	2.0	2.1	1.9
Oregon Average Wage												
Rate (Thous $)	45.3	46.7	47.5	48.0	49.3	50.7	52.3	54.0	55.7	57.5	59.4	61.3
% Ch	3.6	3.1	1.6	1.1	2.7	2.9	3.1	3.3	3.2	3.3	3.3	3.2
U.S. Average Wage												
Wage Rate (Thous $)	50.5	51.8	52.5	53.9	55.7	57.5	59.3	61.3	63.5	65.7	67.9	70.3
% Ch	2.8	2.6	1.4	2.7	3.3	3.2	3.2	3.4	3.5	3.5	3.5	3.4
Housing Indicators												
FHFA Oregon Housing Price Index												
1980 Q1=100	348.2	347.5	373.1	399.2	399.3	404.3	414.1	428.2	445.1	464.0	483.8	503.5
% Ch	(6.8)	(0.2)	7.3	7.0	0.0	1.3	2.4	3.4	3.9	4.3	4.3	4.1
FHFA National Housing Price Index												
1980 Q1=100	312.7	312.5	327.5	368.4	376.9	379.6	388.2	393.9	399.6	407.8	417.8	432.1
% Ch	(3.7)	(0.0)	4.8	12.5	2.3	0.7	2.3	1.5	1.4	2.1	2.4	3.4
Housing Starts												
Oregon (Thous)	8.0	10.9	14.4	15.9	19.6	23.1	23.8	23.8	23.8	23.8	23.8	23.7
% Ch	5.3	35.6	32.6	10.1	23.6	17.7	3.3	(0.2)	0.3	(0.3)	(0.1)	(0.3)
U.S. (Millions)	0.6	0.8	0.9	1.2	1.5	1.6	1.6	1.6	1.6	1.6	1.6	1.5
% Ch	4.5	28.0	18.9	24.8	26.9	10.2	(0.6)	(0.2)	1.3	(1.1)	(3.4)	(1.7)
Other Indicators												
Unemployment Rate (%)												
Oregon	9.6	8.7	7.9	6.8	6.6	6.6	6.6	6.7	6.1	5.7	5.4	5.5
Point Change	(1.1)	(0.9)	(0.9)	(1.1)	(0.2)	0.1	(0.1)	0.1	(0.5)	(0.5)	(0.2)	0.1
U.S.	8.9	8.1	7.4	6.5	5.9	5.4	5.1	5.0	5.0	4.9	5.0	5.1
Point Change	(0.7)	(0.9)	(0.6)	(0.9)	(0.6)	(0.4)	(0.3)	(0.1)	(0.0)	(0.0)	0.1	0.1
Industrial Production Index												
U.S. 2002 = 100	93.6	97.0	99.6	102.5	106.3	110.0	113.3	116.3	119.2	122.2	125.1	128.1
% Ch	3.4	3.6	2.6	3.0	3.7	3.4	3.0	2.6	2.5	2.6	2.3	2.4
Prime Rate (Percent)	3.3	3.3	3.3	3.3	3.4	5.2	6.8	7.0	7.0	7.0	7.0	7.0
% Ch	0.0	0.0	0.0	0.0	5.3	50.7	32.5	2.5	0.0	0.0	0.0	0.0
Population (Millions)												
Oregon	3.86	3.89	3.93	3.97	4.01	4.06	4.11	4.16	4.21	4.26	4.31	4.37
% Ch	0.6	0.7	0.9	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2
U.S.	312.3	314.6	317.0	319.5	321.9	324.4	326.9	329.4	332.0	334.5	337.0	339.5
% Ch	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7
Timber Harvest (Mil Bd Ft)												
Oregon	3,649.0	3,595.0	3,523.0	3,760.6	4,126.5	4,207.3	4,295.1	4,374.4	4,450.4	4,485.4	4,505.5	4,542.5
% Ch	13.1	(1.5)	(2.0)	6.7	9.7	2.0	2.1	1.8	1.7	0.8	0.4	0.8

THE KAISER FAMILY FOUNDATION –AND– HEALTH RESEARCH & EDUCATIONAL TRUST

Employer Health Benefits

2013 Summary of Findings

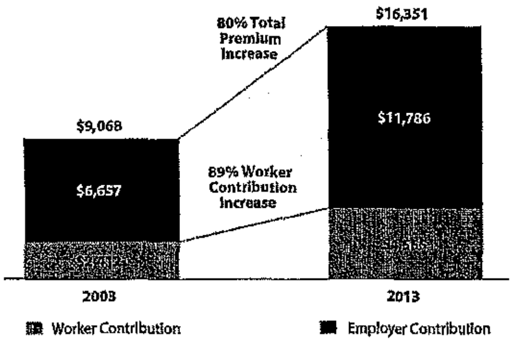
Staff/402
Bahr/6

Employer-sponsored insurance covers about 149 million nonelderly people.[1] To provide current information about employer-sponsored health benefits, the Kaiser Family Foundation (Kaiser) and the Health Research & Educational Trust (HRET) conduct an annual survey of nonfederal private and public employers with three or more workers. This is the fifteenth Kaiser/HRET survey and reflects employer sponsored health benefits in 2013.

The key findings from the survey, conducted from January through May 2013, include modest increases in premiums for both single coverage (5%) and family coverage (4%). Covered workers generally face similar premium contributions and cost-sharing requirements in 2013 compared to 2012. However, the percentage of covered workers enrolled in plans with a general annual deductible increased in 2013, to over three quarters of covered workers (78%). Additionally, over half (58%) of covered workers at small firms (3–199 workers) now have a deductible of a $1,000 dollars or more. The percentage of firms (57%) which offer health benefits to at least some of their employees and the percentage of workers covered at those firms (62%) are statistically unchanged from 2012. The percentage of covered workers enrolled in grandfathered health plans – those plans exempt from many provisions of the Affordable Care Act (ACA) – declined to 36% of covered workers from 48% in 2012 and 56% in 2011. Firms offering health benefits continue to offer wellness and health promotion programs: 77% of firms offer at least one wellness program, 24% offer employees health risk assessments, and 57% offer at least one disease management program. Small percentages of these firms use financial incentives in order to encourage workers to participate or complete these activities.

EXHIBIT A

Average Annual Health Insurance Premiums and Worker Contributions for Family Coverage, 2003–2013



SOURCE: Kaiser/HRET Survey of Employer-Sponsored Health Benefits, 2003-2013.

HEALTH INSURANCE PREMIUMS AND WORKER CONTRIBUTIONS

In 2013, the average annual premiums for employer-sponsored health insurance are $5,884 for single coverage and $16,351 for family coverage. The single premium is 5% higher and the family premium is 4% higher than the 2012 average premiums. During the same period workers' wages increased 1.8% and inflation increased 1.1%.[2] Over the last 10 years, the average premium for family coverage has increased 80% (Exhibit A).

Average premiums for high-deductible health plans with a savings option (HDHP/SOs) are lower than the overall average for all plan types for both single and family coverage (Exhibit B), at $5,306 and $15,227, respectively. Looking at firm size, the average premium for family coverage is lower for covered workers in small firms (3–199 workers) than for workers in larger firms ($15,581 vs. $16,715).

There is significant variation around the average single and family premiums, resulting from differences in benefits, cost sharing, covered populations, and geographical location. Twenty-one percent of covered workers are in plans with an annual total premium for family coverage of at least $19,622 (120% of the average family premium), while 21% of covered workers are in plans where the family premium is less than $13,081 (80% of the average family premium). The distribution is similar around the average single premium (Exhibit C).

Most often, employers require that workers make a contribution towards the cost of the premium. Covered workers contribute on average 18% of the premium for single coverage and 29% of the premium for family coverage, similar to the percentages contributed in 2012 and relatively unchanged over the past decade. Workers in small firms (3–199 workers) contribute a lower average percentage for single coverage compared to workers in larger firms (16% vs. 19%), but they contribute a higher average percentage for family coverage (36% vs. 26%). Workers in firms with a higher percentage of lower-wage workers (at least 35% of workers earn $23,000 or less) contribute higher percentages of the premium for single coverage (23% vs. 17%) and for family coverage (39% vs. 29%) than workers in firms with a smaller share lower-wage workers.

As with total premiums, the share of the premium contributed by workers varies considerably among firms. For single coverage, 62% of covered workers

PGE UE 283
Test Year Ending December 31, 2015
000's of Dollars

S-11 Medical Benefits Adjustment

The adjustment reflects Staff's recommendation of employer/employee sharing of 82/18, rather than that proposed by the Company of 85/15. The sharing percentage used by Staff is the industry average obtained from a recent KFF survey. Staff also proposes removing the proportional amount of medical benefits related to Staff's recommended adjustment to the Company's proposed level of FTE.

	Company Filing	Staff	Adjustment
Description/ Account No.	OR-Allocated	OR-Allocated	OR-Allocated
Medical Benefits (sharing)	$81,884	$81,101	$ 783
Medical Benefits (FTE)	$81,884	tbd	tbd

Staff Initiator:
Brian Bahr

S-11.1 Non-Union Medical, Dental, & Vision Benefits Adjustment

$1,899,838	Total 2013 Medical Benefits (Non-Bargaining only)
$186,391	Total 2013 Dental Benefits (Non-Bargaining only)
$20,508	Total 2013 Vision Benefits (Non-Bargaining only)
$2,106,737	Total 2013 Benefits (Non-Bargaining only)

Sharing % Adjustment

1817	2015 Non-union FTE Count per DR 95
$1,159	2013 Monthly Cost Per 2015 FTE
12	Annualized
$13,914	2013 Annual Cost Per 2015 FTE
1.4%	2014 Escalation Factor **
1.8%	2015 Escalation Factor **
$14,362	2015 Annual Cost Per 2015 FTE
85%	Sharing percentage per DR 64
$12,208	Net 2015 Annual Cost Per 2015 FTE (Company)
82%	Staff Adjusted Sharing Percentage *
$11,777	Net 2015 Annual Cost Per 2015 FTE (Staff)
$21,398,889	Total Staff Allowed Expense
$22,181,775	Total Company Expense
-$782,886	Staff Adjustment (related to Staff recommended reduction to sharing percentage)

FTE Adjustment

2015 Benefits per PGE WP 600 'Total Comp'	
1,778,453	Health Reimbursement Account
1,081,358	Group Life Insurance
56,385	Employee Assistance Program
15,198,415	Pension Plan
462,735	Education Plan
587,618	Benefits Administration
19,164,963	**Non FTE Sensitive Benefits**
42,685,991	Health & Dental Plan
307,320	Employee Wellness Program
558,567	Short Term Disability Insurance
2,229,970	Long Term Disability Benefits
16,656,263	Retirement Savings Plan
280,495	Misc. Employee Benefits
62,718,606	**FTE Sensitive Benefits**
2,566.8	2015 Total FTE Count per DR 95
$24,434	**2015 Annual Benefits Cost Per 2015 FTE**
tbd	FTE Adjustment per S-13
tbd	**Staff Adjustment to Benefits based on FTE**

$81,883,569	**2015 Total PGE Share Benefit Costs per PGE WP 600 'Total Comp'**
$81,100,683	**Staff proposed amount (less $24,434 * FTE adjustment)**

* Staff recommends 82/18 sharing based on results of the Kaiser Family Foundation 2013 Employer Health Benefits Survey published Aug 20, 2013.
http://kff.org/report-section/2013-summary-of-findings/
"Most often, employers require that workers make a contribution towards the cost of the premium. Covered workers contribute on average 18% of the premium for single coverage and 29% of the premium for family coverage, similar to the percentages contributed in 2012 and relatively unchanged over the past decade."

** Staff uses the U.S. Urban Consumers CPI Index found on page 41 of the following pdf:
http://www.oregon.gov/DAS/OEA/docs/economic/forecast0314.pdf

Staff/402
Bahr/9-10

These pages are confidential.

You must have signed the Protective Order in this docket in order to view this page.

March 12, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE *First Supplemental* Response to OPUC Data Request No. 095
Dated February 13, 2014

Request:

For the test year and the preceding 4 calendar years, please provide (on a total company basis), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year. Please note which months and figures are associated with both the actual and forecast data.

Year 2XXX	Actual (Unadjusted) Paid Cash Compensation				
Category	Total Company FTE*	Base Wages or Salaries	Overtime	Incentive or Bonus	Total
Officers					
Exempt					
Nonexempt					
Union					
Total					
*Please Exclude Full-Time Equivalent Created by Overtime					

Response:

Attachment 095-A provides PGE FTEs, base wages and salaries. End of year actuals are provided for 2011 and 2012, while 2013 provides actuals through September 2013 and 2014-2015 are forecasted amounts. The FTE and dollar amounts associated with PGE's pre-filing adjustments have been apportioned to the appropriate employee categories based on both the specific forecasted reductions (for specific pre-filing reductions) and PGE's forecasted 2015 employee category percentages (for PGE's "unfilled position" reduction).

The second tab of Attachment 095-A provides incentive costs for 2011 (actuals) through 2015 (forecast). PGE tracks paid incentive amounts by employee on a cash basis, while PGE's revenue requirement (including our incentive request) is provided on an accrual basis. In order to segregate PGE's incentive programs (in particular the PIC program) by employee category (union, exempt, non-exempt, officer), we apportioned the program cost by employee category pro rata, using the total base salaries for employees included within the respective incentive programs.

The third tab of Attachment 095-A provides overtime costs for 2011 (actuals) through 2015 (forecast).

First Supplemental Response (Dated: March 12, 2014):

Attachment 095-B provides a copy of the requested information with updated actual 2013 results as requested in OPUC Data Request No. 133.

UE 283

Attachment 095-B

Provided in Electronic Format only

FTEs, Wages and Salaries, Incentives, and Overtime – 2011-2015

FTEs, Wages & Salaries 2011-2015

Class	2011 FTE Actuals	2011 W&S Actuals
EXEMPT	1247.0	$116,047,618.69
HOURLY	492.7	$22,533,426.30
OFFICER	12.6	$3,372,324.59
UNION	791.3	$62,632,404.63
Total	2543.5	$204,585,774.21

Class	2012 FTE Actuals	2012 W&S Actuals
EXEMPT	1254.9	$122,826,172.70
HOURLY	480.5	$22,236,123.16
OFFICER	11.9	$3,525,987.69
UNION	749.2	$60,335,672.23
Total	2496.4	$208,923,955.77

Class	2013 FTE Actuals	2013 W&S Actuals
EXEMPT	1256.7	$125,317,804.63
HOURLY	459.1	$21,616,459.22
OFFICER	11.9	$3,713,476.00
UNION	725.4	$57,372,088.70
Total	2453.1	$208,019,828.55

Class	2014 FTE Budget	2014 W&S Budget
EXEMPT	1335.9	$138,449,821.62
HOURLY	505.5	$26,222,281.11
OFFICER	12.0	$3,905,875.18
UNION	759.5	$60,870,615.79
Total	2612.9	$229,448,593.70
PGE Prefiling Adjustment	-57.1	-$6,000,000.00
Net Total	2555.8	$223,448,593.70

Class	2015 FTE Budget	%	Specific Removals	Pro Rata Adjustments	2015 FTE Budget w/Adj.	2015 W&S Budget	2015 W&S Budget w/Adj.
EXEMPT	1370.7	52.2%	(9.5)	(28.7)	1332.5	$147,915,547.70	$142,892,386.98
HOURLY	483.1	18.4%	(0.5)	(10.1)	472.5	$24,985,591.42	$23,861,652.21
OFFICER	12.0				12.0	$4,081,639.56	$4,068,109.31
UNION	771.2	29.4%	(5.2)	(16.1)	749.9	$63,584,597.52	$61,345,898.70
Total	2636.9					$240,567,376.20	
PGE Prefiling Adjustment	-70.1					-$8,399,329.00	
Net Total	2566.8				2566.8	$232,168,047.20	$232,168,047.20

February 13, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 064
Dated February 13, 2014

Request:

Please provide the current employer / employee contribution for each labor group (non-represented, and each union group) for medical (health, dental, and vision) plans (i.e. 90/10, 85/15, 80/20, etc.). Is the Company anticipating any change to these percentages for the Test Year? Please explain.

Response:

The current employer/employee contribution for all non-bargaining employees and bargaining employees at Coyote Springs /Port Westward is 85/15 for medical premiums. This is a weighted average for Providence and Kaiser. The same sharing ratio applies to the dental and vision premiums.

The bargaining unit, IBEW Local 125, employer/employee contribution ratio is 90/10 per the union contract. According to the 2009-2015 contract extension, the sharing ratio was held at 90/10 for 2013 and 2014 with a trade-off of reducing wage increases by 0.5% for each year.

The non-bargaining employer/employee premium-sharing ratio is not expected to change in 2015. The union employer/employee contribution ratio is subject to contract negotiations that are currently in the preliminary stages. The current contract is set to expire on February 28, 2015.

April 9, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE *First Supplemental* Response to OPUC Data Request No. 063
Dated February 13, 2014

Request:

In the following table format, please provide medical benefit costs for the test year, historical base year, and the three years prior to the historical base year. Please also explain if the amounts reflected in the Company's response are before or after employer/employee sharing. For the test year estimates, please explain the assumptions relied upon (i.e. increased employees, specific escalation factor to premiums, etc) in arriving at the forecasted amounts.

	Test Year	Base Year	Base Year - 1	Base Year - 2	Base Year - 3
Medical					
Dental					
401(k)					
Group Life Insurance					
Retiree Life Insurance					
Long-Term Disability					
Other (Please Label)					
Total					

Response:

Please refer to Attachment 063-A for the detail of requested benefit costs. Note that the categories are slightly different than above as PGE groups costs into different categories. The assumptions relied upon for test year estimates are described as follows:

Health & Dental:

Premiums for active union health insurance are based upon a forecasted premium increase of approximately 9% for 2015 with no increase in the union employee population. Union retiree medical expense for 2015 is based on a discount rate of 4.72% and an assumed Expected Return on Assets (EROA) of 7.5%.

Health insurance premiums for active non-union employees are based on the following rate increase forecasts for 2015 provided by Mercer, along with a slight increase in participant size due to changes in federal legislation affecting temporary employee benefits:

Kaiser Medical	7.5%
Kaiser Dental	7.5%
Providence	9.0%
MetLife Dental	6.0%

Non-union retiree medical expenses for 2015 are based on a discount rate of 4.72% and an assumed EROA of 7.5%.

Health & Wellness:

Increases in health and wellness for 2015 are based on inflation of supplies and vendor contracts.

Health Reimbursement Account (HRA):

Decreases to the HRA for 2015 are due to the union compensable hours worked contribution of $1 per straight time hour being moved to the long-term disability account beginning in 2014. See PGE Exhibit 600 for further detail. For non-union employees, a discount rate of 4.66% is used. The administration of both plans assumes participant counts continue to increase at the same rate as historical trends.

Short-term disability:

Assumes a contract renewal rate increase of 10% effective May 1, 2014 and negotiated union wage increases and claims history. Non-union short-term disability costs are included in wage and salary costs.

Long-term disability (LTD):

Actuarial forecasts of union and non-union LTD medical costs are provided by Towers Watson and include an increased discount rate of 3.4%, number of current participants, demographics of the population, and projections of usage based on history.

Retiree Life Insurance:

Costs for union retirees are based on a discount rate increase to 4.88%. Non-union retiree costs are based on a discount rate of 5%. Active union and non-union members pay for their own life insurance.

401(k):

Assumptions used for the 401(k) are based upon the employee demographics as of July 2013. Additional assumptions include wage increases for exempt, nonexempt, and union employees.

Pension:

The assumptions used for pension costs are a 4.76% discount rate and a long-term rate of return of 7.5%. Please refer to Section V of PGE Exhibit 600 for more detail on how these assumptions are derived. Please note, the amount listed in Attachment 063-A for pension cost is the full amount of PGE's pension expense cost for 2015. The costs requested in PGE Exhibit 600 are the post-capitalization portion of FAS 87 expense along with a return on PGE's prepaid pension asset, net of the associated deferred taxes.

First Supplemental Response (Dated: April 9, 2014):

Attachment 063-B provides a copy of the requested information with updated actual 2013 results as requested in OPUC Data Request No. 272.

UE 283

Attachment 063-B

Provided in Electronic Format only

Summary of Benefit Costs

Summary of Benefit Costs
(Non-labor costs only at PGE's share)

	Benefit Description	2015 Forecast	2014 Budget	2013 Actuals	2012 Actuals	2011 Actuals
1	Health & Dental	42,685,991	39,297,935	37,269,048	37,097,853	36,386,643
2	Health & Wellness	307,320	301,100	328,500	219,890	355,957
3	Health Reimbursement Account	1,778,453	1,707,749	1,266,278	3,997,033	1,436,152
4	Short-term Disability Insurance	558,567	511,382	473,033	473,552	464,118
5	Long-term Disability Insurance	2,229,970	2,133,210	1,518,912	1,180,571	1,666,413
6	Retiree life Insurance	1,081,358	1,105,600	1,372,780	1,222,661	1,087,034
8	401(k) Plan	16,656,263	16,076,384	15,574,309	15,556,414	15,861,757
9	Pension Plan	25,195,525	25,800,000	31,054,872	20,605,550	8,170,862
	Total	$ 90,493,446	$ 86,933,360	$ 88,857,733	$ 80,353,524	$ 65,428,935

April 9, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 279
Dated March 26, 2014

Request:

Please complete the following table regarding employee dental enrollment for 2013 or the most current full year for which you have data. If 2013 is not available, please explain why.

Employee Count	Employee Only	Employee & Spouse	Employee & Child	Family
Met Life				
Kaiser				

Response:

The average 2013 totals are provided below:

2013 Average Dental Enrollment					
Employee Count	Employee Only	Employee & Spouse	Employee & Child	Family	Total
Coverage Waived					112
MetLife Dental	290	271	92	421	1074
Kaiser Dental	175	127	65	188	554

April 9, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 280
Dated March 26, 2014

Request:

Please complete the following table regarding employee vision enrollment for 2013 or the most current full year for which you have data. If 2013 is not available, please explain why.

Employee Count	Employee Only	Employee & Spouse	Employee & Child	Family
VSP				

Response:

The average 2013 totals are provided below:

2013 Average Vision Enrollment					
Employee Count	Employee Only	Employee & Spouse	Employee & Child	Family	Total
Coverage Waived					479
VSP Vision	401	360	119	429	1309

April 9, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 276
Dated March 26, 2014

Request:

Please complete the following table regarding employee medical enrollment for 2013 or the most current full year for which you have data. If 2013 is not available, please explain why.

Employee Count	Employee Only	Employee & Spouse	Employee & Child	Family	Opt Out
Waive					
Providence Personal Option					
Providence Personal Option					
Providence Open Option					
Providence High Deductible Health Plan					
Providence Traditional Plan					
Kaiser					
Kaiser HDHP					

Response:

The average 2013 totals are provided below. Not included within these medical plans are 48 PGE employees who have transitioned from union to non-union positions and retained their EBA union medical and dental plan. While these employees do retain their EBA health and dental coverage, the payment of their premiums is consistent with the fixed company contribution allocations received by the rest of PGE's non-union employee population.

2013 Average NB Medical Enrollment					
Employee Count	Employee Only	Employee & Spouse	Employee & Child	Family	Total
Coverage Waived					124
Providence Personal	235	156	69	213	672
Providence Open	31	17	4	22	74
Providence Traditional	2	11	5	20	38
Providence HDHP	27	32	6	60	125
Kaiser	178	141	78	244	641
Kaiser HDHP	22	9	2	32	65

April 9, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 275
Dated March 26, 2014

Request:

For each Medical (Health, Dental, and Vision) plan, please identify the premium amount for 2010, 2011, 2012, and 2013. If the premium amounts vary by labor group, please provide the information for each labor group separately.

Response:

Attachment 275-A provides a summary of premium amounts for all health, dental, and vision plans for 2010, 2011, 2012 and 2013. Attachment 275-A is confidential and subject to Protective Order No. 14-043.

UE 283

Attachment 275-A

Provided in Electronic Format only

Confidential and Subject to Protective Order No. 14-043

2010-2013 Summary of Premium Costs

Staff/402
Bahr/27

This page is confidential.

You must have signed the Protective Order in this docket in order to view this page.

CASE: UE 283
WITNESS: Linnea Wittekind

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

REDACTED
June 11, 2014

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 500

UE 283 ARE CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 14-043. YOU

MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 283 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

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

A. My name is Linnea Wittekind. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/501.

Q. What issues were you responsible for in this docket.

A. I was assigned Director and Officer (D&O) insurance and various Administrative and General (A&G) expenses.

Q. Are either of those issues included in the partial settlement reached among parties to this rate case?

A. Yes, my adjustment to various A&G expenses was resolved. Staff anticipates that the stipulation and supporting testimony will be filed in June, 2014. I would like to note that in analyzing various A&G expenses, I reviewed five Standard Data Requests and submitted one additional follow up data request.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to recommend adjustments to Portland General Electric's (PGE) D&O liability insurance expense.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/502, detailing the calculation of the adjustment , Exhibit Staff/503, a copy of the Towers Watson Directors and Officers Survey, and Exhibit Staff/504 copy of page 20 from Commission Order No. 09-020.

Q. How is your testimony organized?

A. My testimony is organized as follows:

My adjustment is based on PGE's filing, PGE's November 14, 2012 Insurance Program presentation and the Company's response to two Staff data requests.

Issue 1, D&O INSURANCE EXPENSE ADJUSTMENT

Q. Please summarize this adjustment.

A. This adjustment is shown in Confidential Exhibit Staff/502, Wittekind/1 and focuses on PGE's D&O liability insurance. I propose the following adjustment:

D & O Insurance ($[redacted])

In UE 283, PGE submitted a total 2015, D&O Insurance cost of $[redacted]. I recommend a total cost of $[redacted] for 2015. As shown in Confidential Exhibit Staff/502, Wittekind

V1, the difference is $[redacted].

Q. Please explain your adjustment to D&O liability insurance.

A. I reduced the total 2015 D&O Liability Insurance by 50 percent. I examined PGE's total D&O insurance cost for Sides A, B, and C as well as Side A difference-in-conditions (DIC). PGE proposes to include the total D&O insurance cost, which includes the Sides A, B, and C as well as Side A DIC, in rates. Staff recommends a 50 percent sharing for all sides including Side A DIC.

Q. How is PGE's D&O Liability Insurance structured?

A. PGE's D&O Liability Insurance has three layers/sides of coverage. The layers are A, B, C, and Side A DIC.

Q. What coverage is provided under each of the policy layers?

A. According to the Company, Side A provides individual coverage and insures against non-indemnifiable losses. Side B provides coverage for corporate reimbursement and insures the Company's indemnification obligation to the directors and officers. Side C provides entity coverage and insures the corporate entity when "named" as a defendant in securities claims.

Q. What is the basis for your adjustment?

A. In PGE's general rate case filed in 2008, Staff proposed that customers and ratepayers share the cost of D&O liability insurance. The Commission agreed the cost of D&O liability insurance should be split between ratepayers and shareholders. In fact, the Commission ordered that the Company absorb a greater amount of the cost of D&O insurance than proposed by Staff:

> We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost.[1]

Q. Why does Staff support a 50/50 percent sharing of the cost of D&O liability insurance between ratepayers and shareholders?

First, a sharing approach aligns the interest of customers and shareholders. Second, customers, typically have no say in electing or appointing utility directors or officers, and therefore should not be held financially responsible for providing 100 percent of the insurance coverage against business decisions or improprieties by management that results in lawsuits. Additionally, according

[1] OPUC Order No. 09-020 at 19-20 (Docket No. UE 197). (An excerpt of the order is included in Staff Exhibit 504.)

to the 2012 Towers Watson Directors and Officers Liability Survey, "derivative shareholder/investor suits and direct shareholder/investor suits continue to lead the types of claims filed over the last ten years."[2]

Customers should not be required to pay the full costs of insurance needed to pay costs associated with defense against suits brought by shareholders.

Q. Does this conclude your direct testimony?

A. Yes.

[2] Towers-Watson-Directors-and-Officers-Survey-2012.pdf, http://www.towerswatson.com/en/Insights/IC-Types/Survey-Research-Results/2013/03/Directors-and-Officers-Liability-2012-Survey-of-Insurance-Purchasing-Trends, included in Exhibit Staff/503.

CASE: UE 283
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME: Linnea Wittekind

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst,
Energy – Rates, Finance, and Audit Division

ADDRESS: 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

EDUCATION: B.S. Western Oregon University
Major: Business with focus in Accounting
Minor: Entrepreneurship

EXPERIENCE: Since November 2009, I have been employed by the Public Utility Commission of Oregon. Responsibilities include research, analysis and recommendations on a wide range of cost, revenue and policy issues for electric and natural gas utilities. I have provided testimony in UE 215, UE 233, UG 221, UE 246, and UE 262 and have filed comments in LC 50 as well as several affiliated interest and property sale dockets. I have also reviewed and analyzed a number of energy efficiency tariff filings. I've written several public meeting memos summarizing my analysis of energy efficiency tariff filings. I have performed operational audits of NW Natural, Cascade Natural Gas, and Portland General Electric as well as assisted in an operational audit PacifiCorp. Recently I've completed an audit regarding gas accounting best practices.

Through the Public Utility Commission of Oregon, I am a member of the NARUC Staff Subcommittee on Accounting & Finance.

I've attended a number of trainings which include, The Basics through the Center for Public Utilities, New Mexico State University, Best Practices in an Era of Renewables and Reduced Emissions through EUCI as well as Benchmarking the Performance of Electric and Gas Distribution Utilities also through EUCI. I've also attended the Advanced Regulatory Studies Program through the Institute of Public Utilities at Michigan State University.

From July 2005 to November 2009, I worked as a Tax Auditor for the Oregon Department of Revenue. In enforcement of tax laws, rules and regulations, I performed income tax audits of individual tax payers and small businesses. Additionally I prepared cost analysis of tax credits and measures. I also represented the department before the Oregon Tax Court for tax deficiency appeals.

CASE: UE 283
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

REDACTED
June 11, 2014

STAFF EXHIBIT 502

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 14-043. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 283 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

CASE: UE 283
WITNESS: LINNEA WITTEKIND

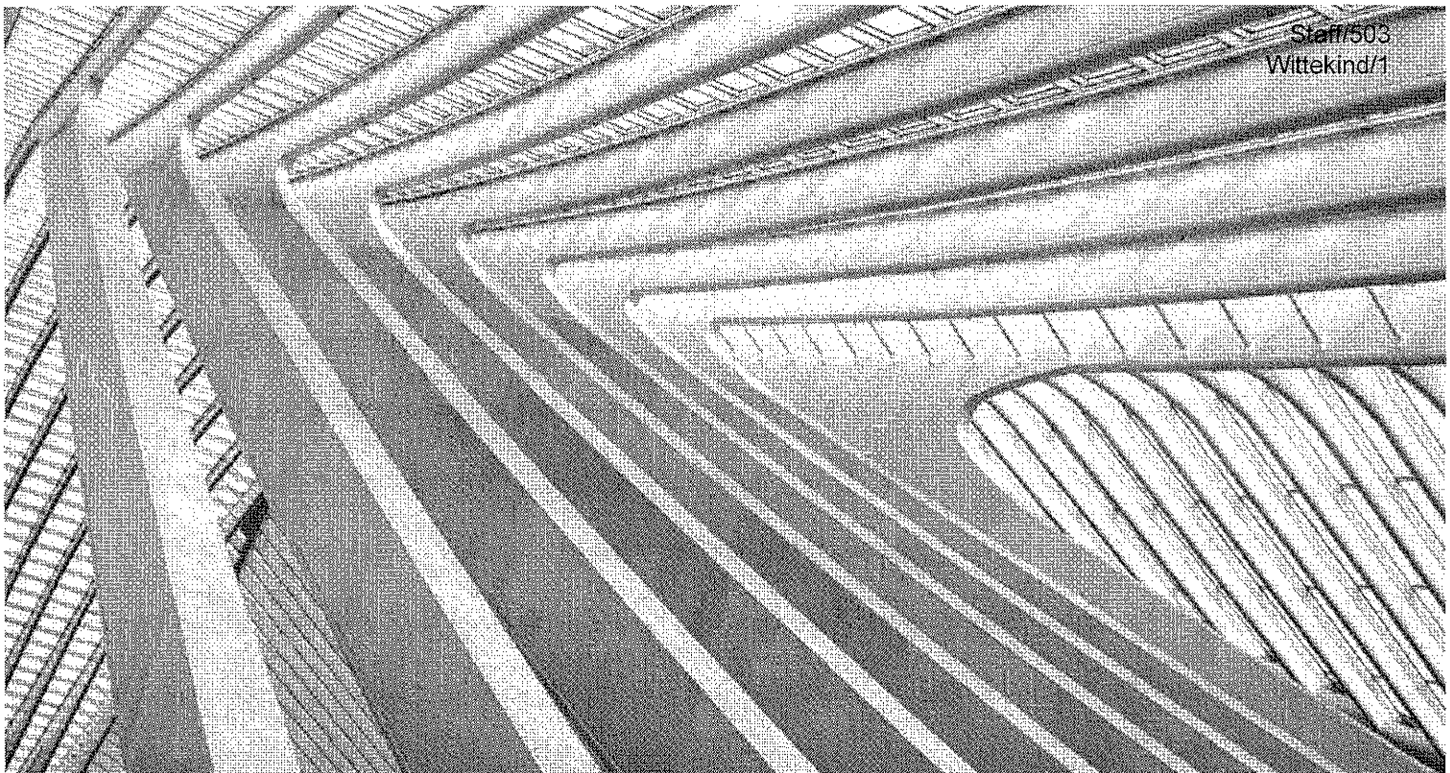
PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 503

Exhibits in Support
Of Opening Testimony

June 11, 2014

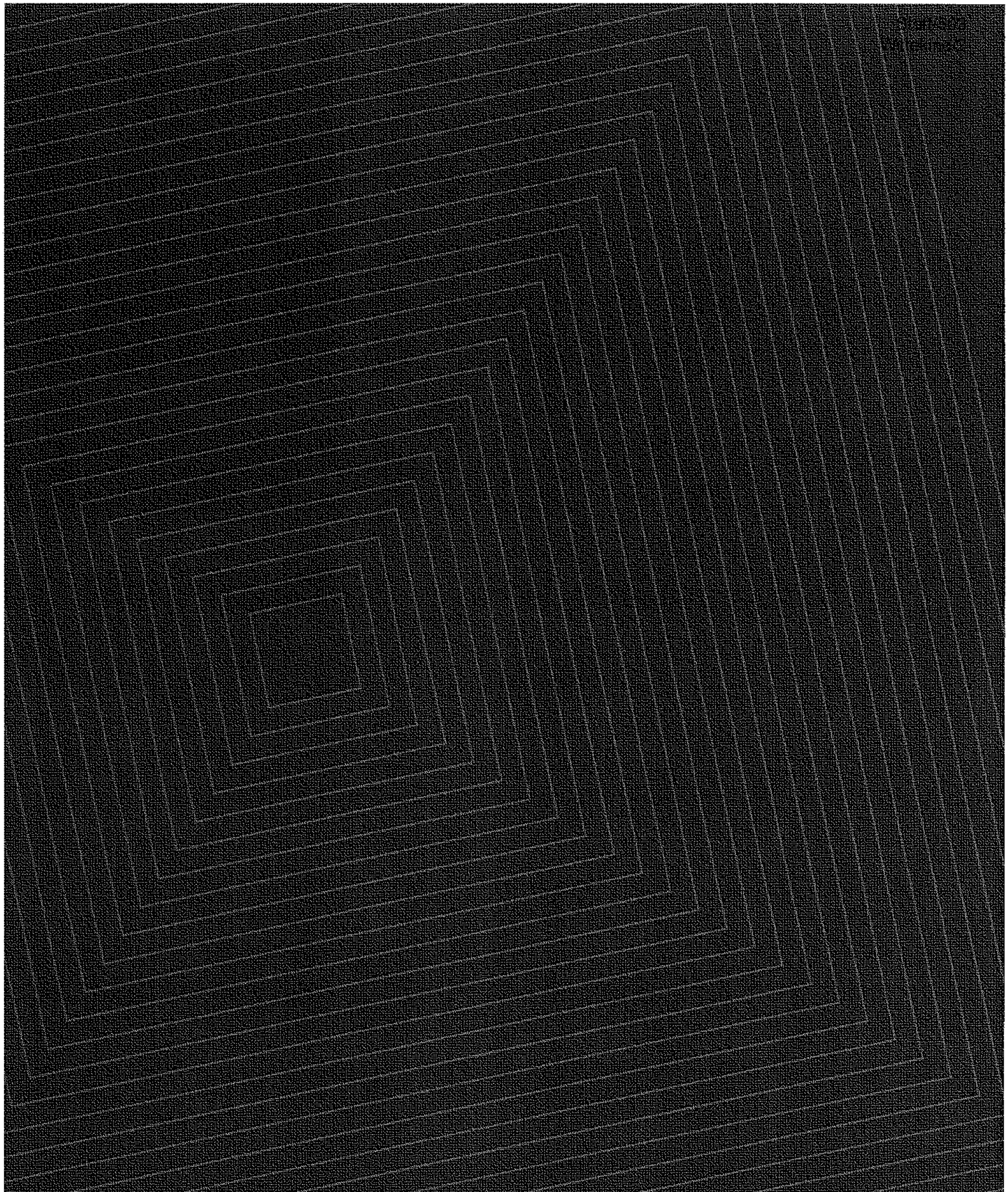
Staff/503
Wittekind/1



Directors and Officers Liability Survey

2012 Summary of Results

TOWERS WATSON



Directors and Officers Liability Survey

2012 Summary of Results

Table of Contents

Introduction

Welcome to the 2012 Directors and Officers (D&O) Liability Survey, the 34th in a series of studies conducted by Towers Watson.

The 2012 survey was conducted online from October 23 through December 7, 2012. A total of 325 organizations that purchase D&O liability insurance participated in the survey.

Consistent with years past, our goal was to provide data about an organization's D&O program and was not intended to capture information relative to other lines of coverage (employment practices liability, fiduciary liability, among others).

When reviewing the data, it is important that care is taken when drawing conclusions about the overall D&O insurance market and trends. You will note that the majority of respondents were large organizations with total assets/revenues in excess of US$1 billion. Conversely, firms with assets/revenues under US$1 billion were not as well represented, creating a smaller pool of respondents. This is particularly relevant to the figures with respect to policy limits.

In an effort to provide more meaningful data, we once again broke many of our responses into two categories, public and private/nonprofit. When we felt the information conveyed a material change, we also included comparisons to the 2011 survey.

For the better part of the past decade, with certain industry exceptions, it was fair to categorize the overall D&O market as favorable. Such conditions were due in part to an influx of new capacity. Buyers typically secured year-over-year price reductions and broadened policy terms. As you will see in the enclosed report, we find ourselves in a transitioning D&O market. This transition was most evident in the private/nonprofit space, with 41% reporting an increase in premium to their primary program (up from 18% in 2011). The public sector has been slower to respond, with just as many firms reporting an increase to their primary program as a decrease (29%).

Directors and officers — and their respective organizations — continue to be susceptible to a much wider range of claimants than in years past. In fact, traditional securities class-action litigation ranked fourth in new legal filings in Advisen's *D&O Claims Trends: 2012 Wrap Up*, behind securities fraud cases, breach of fiduciary duty cases and derivative actions.

We have also provided a directory of insurers that write D&O coverage.

Sincere thanks once again to those who participated in this year's survey, as well as to Dan Bailey (of Bailey Cavalieri LLC) and Kevin LaCroix and Chris Pass (of RT ProExec) for their feedback and continued contributions to this survey.

It is because of your support and participation that we are able to offer this unique report on D&O liability insurance and purchasing trends. We hope you enjoy reading our report as much as we enjoy providing it.

Lawrence A. Racioppo
Executive Liability, Towers Watson
larry.racioppo@towerswatson.com

2012 Survey Highlights

- The insurance marketplace for D&O liability is clearly in a state of transition, as evidenced by increased pricing experienced in many sectors. Of particular note are the private/nonprofit organizations surveyed, with 41% experiencing an increase in premium.
- In 2012, directors and officers, particularly among private companies, were more likely to ask about the amount and scope of D&O coverage.
- Regulatory claims continue to be a significant source of concern, with 83% of respondents ranking this area in the top three overall.
- Side A policies continue to be important components of an organization's D&O program. Purchasing patterns for dedicated Side A policies among private companies continue to increase, with 41% including a Side A layer as part of their D&O program. This is an increase from 34% in 2011.
- Breadth of coverage was considered the most important attribute of a primary D&O policy, while financial strength (e.g., A.M. Best rating) ranked as most important when considering an excess carrier.
- 63% of our nonprofit respondents reported having a claim within the past 10 years.
- One in five (21%) respondents are dissatisfied with the manner in which their D&O claim was handled.
- All dollar amounts reported are in U.S. dollars.

Participant Profile

The 325 participants in Towers Watson's 2012 D&O Liability Survey represent many industry sectors, with a heavier weighting in manufacturing (20%), insurance (13%), and energy and utilities (12%) *(Figure 1)*. The majority of these participants (61%) are public companies, while private companies represent 20% of participants and nonprofits, 13% *(Figure 2)*.

Figure 1. Participation by business class

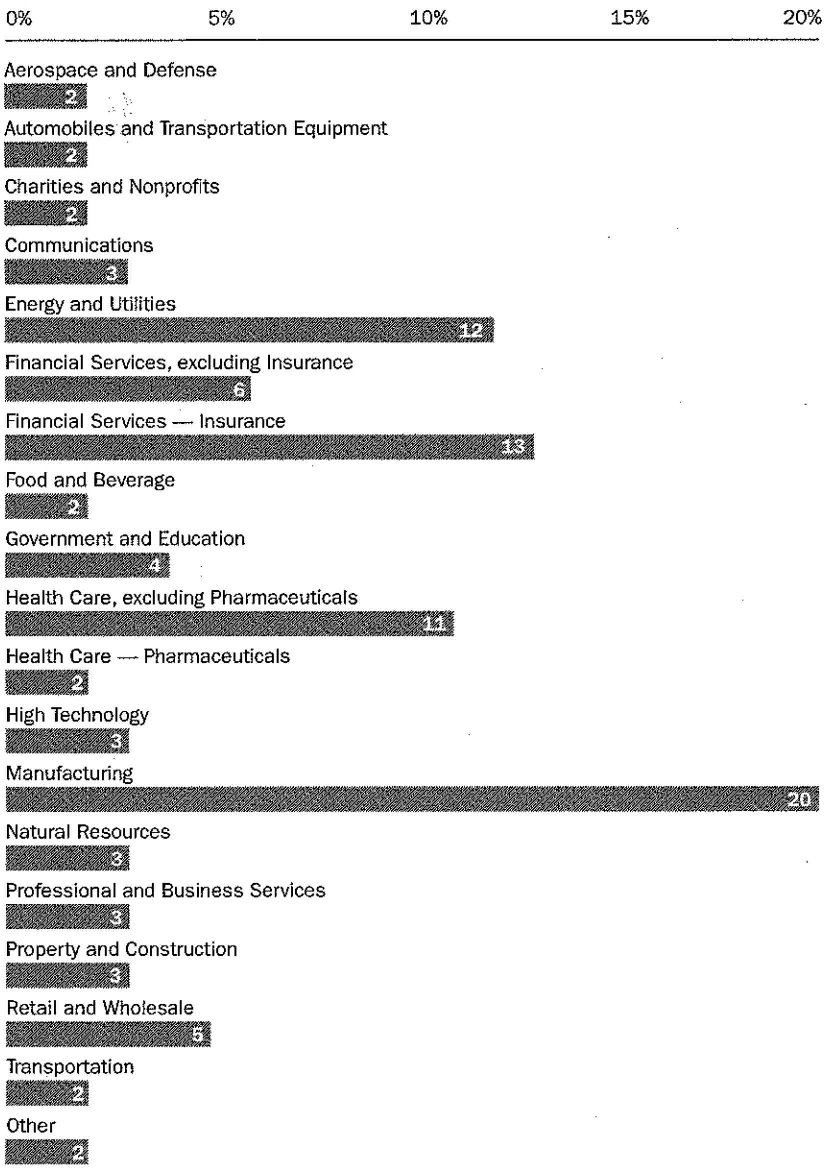
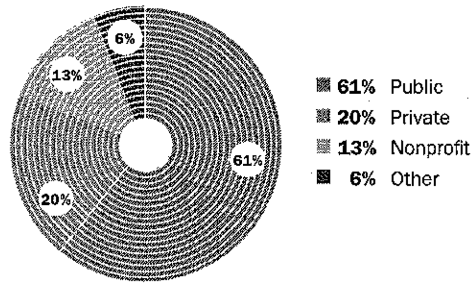


Figure 2. Participation by ownership



By far, most respondents are in the $1 billion – $4.9 billion business class when measured by total revenues (43%), total assets (32%) and market capitalization (43%), excluding charities and nonprofits *(Figure 3)*. This business class represented 113 participants by revenue and 78 participants by assets. The three largest business

Figure 3. Participation by size

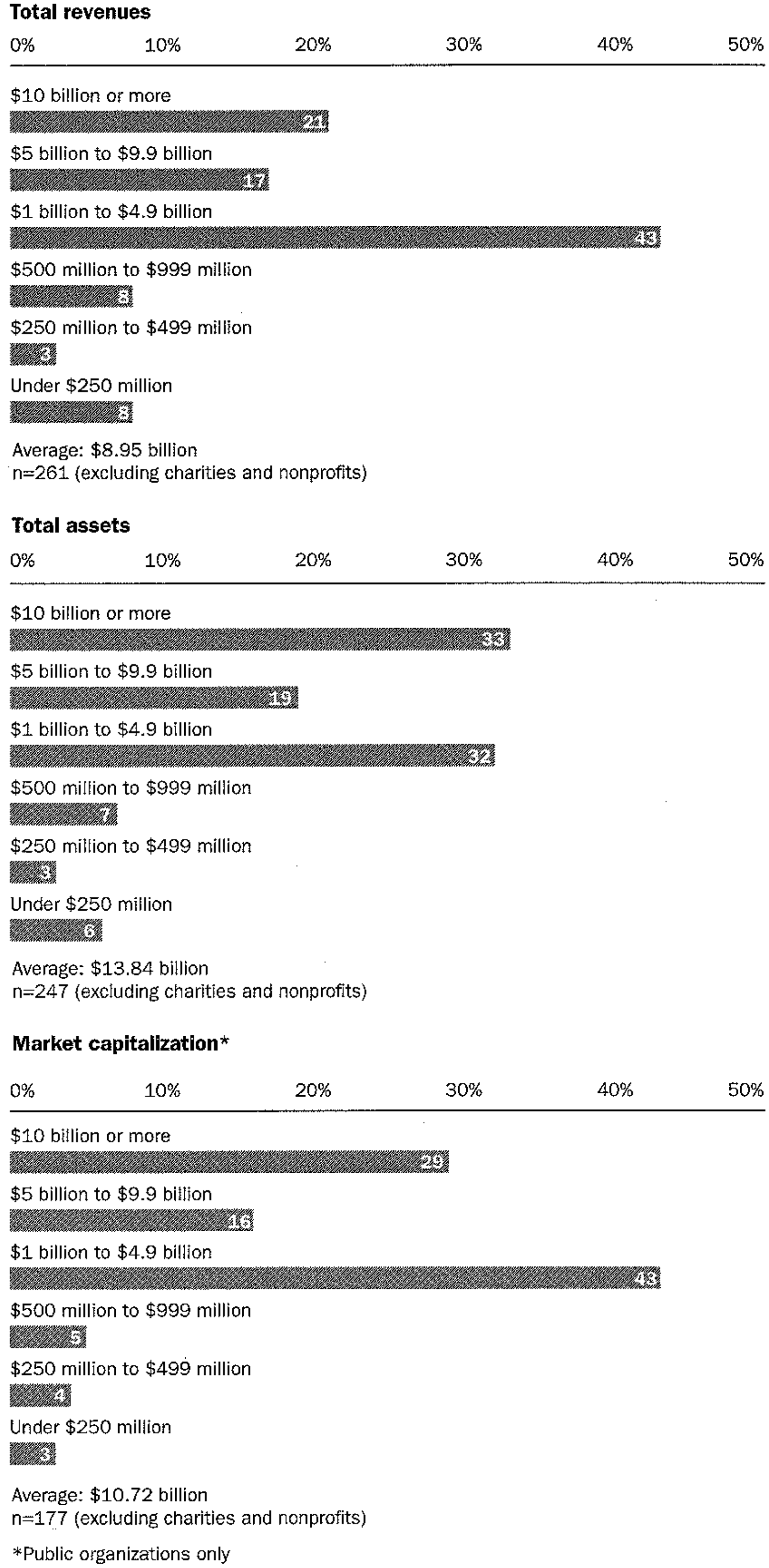
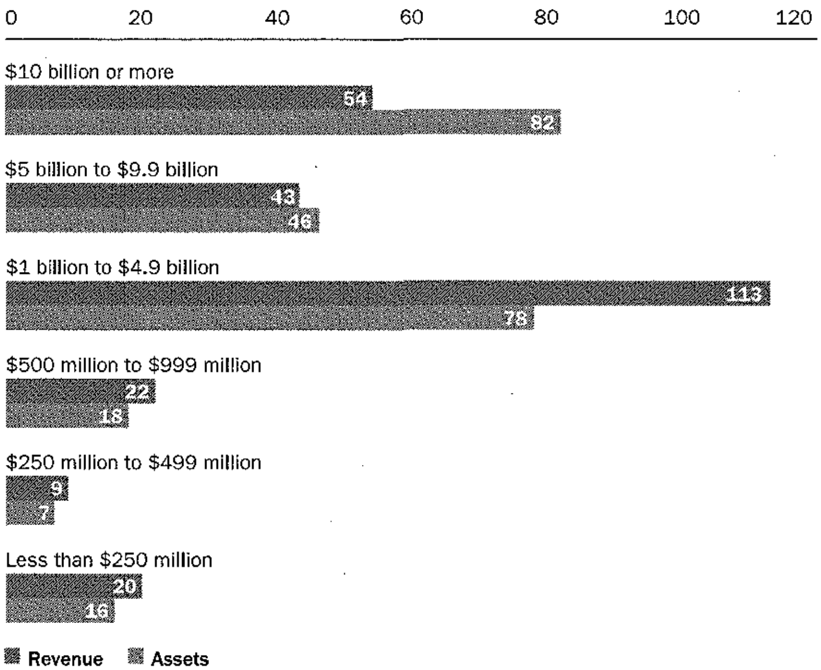


Figure 4. Number of participants by size*



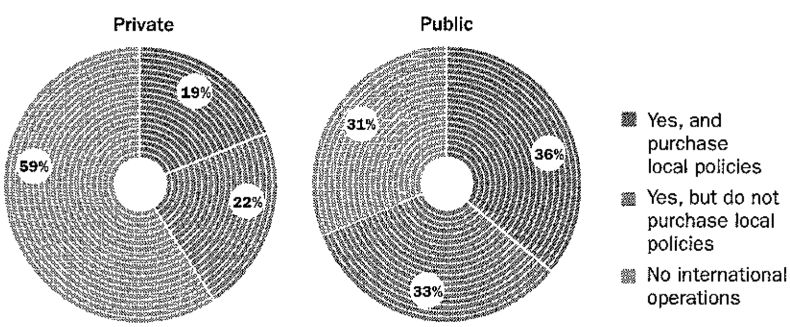
*Excluding charities and nonprofits

Figure 5. International operations by ownership

	Yes	No
Nonprofit	**24%**	**76%**
Private	**41%**	**59%**
Public	**69%**	**31%**
All groups, excluding charities and nonprofits	**62%**	**38%**
All groups (total respondents)	**54%**	**46%**

Figure 6. International local policy purchases

Does your organization have international operations? Do you purchase local policies in foreign jurisdictions?



classes, which when taken together range from $1 billion to $10 billion or more, represented the majority of respondents (210 by revenue and 206 by assets) *(Figure 4).*

Sixty-nine percent of public companies that responded have international operations *(Figure 5)*, and of those participants, a little under half did not purchase a locally issued policy in their foreign locations. Of the private companies surveyed, 59% stated they have no international operations, while those that do have international exposure were comparatively slightly less likely to purchase international policies *(Figure 6).*

Midsize and larger companies, as measured by asset size, were more likely to purchase local policies, as witnessed by positive responses from 56% of participants in each of the three larger size categories: $1 billion to $4.9 billion, $5 billion to $9.9 billion, and $10 billion or more *(Figure 7)*. The results are not surprising, as larger companies typically operate in more foreign countries, which would naturally increase their need for a local policy in one or more countries. That said, because it is unclear where respondents maintain a foreign presence, the decision not to buy a local policy may be very reasonable for similarly sized companies.

Interest in the amount and scope of coverage increased for both private and public companies. Most notably, 70% of directors and officers at private companies raised the issue, a 12-percentage-point increase over 2011's 58%. Interest among public companies edged up from 77% in 2011 to 80% in 2012 *(Figure 8)*. Over two-thirds of both public and private respondents (69%) made an inquiry in 2011, compared with 57% in 2010. In our view, the increase in interest level among directors and officers is indicative of the sensitive nature of the coverage and their concern over the litigious environment they must navigate.

The number of companies that conducted an independent review of their D&O liability policies in the past two years was unchanged (47%) from the 2011 survey. This year, respondents were a little more likely to use a law firm (25% versus 21% in 2011) and a little less likely to use another broker (13% versus 17% in 2011) *(Figure 9)*.

Figure 7. Purchase of local policies by asset size

	Yes	No
Less than $250 million	**20%**	**80%**
$250 million to $999 million	**36%**	**64%**
$1 billion to $4.9 billion	**56%**	**44%**
$5 billion to $9.9 billion	**56%**	**44%**
$10 billion or more	**56%**	**44%**
All size groups, excluding charities and nonprofits	**52%**	**48%**
All groups (total respondents)	**51%**	**49%**

Figure 8. D&O inquiries
During the past 12 months, has a director or officer of your company inquired as to the amount and scope of coverage?

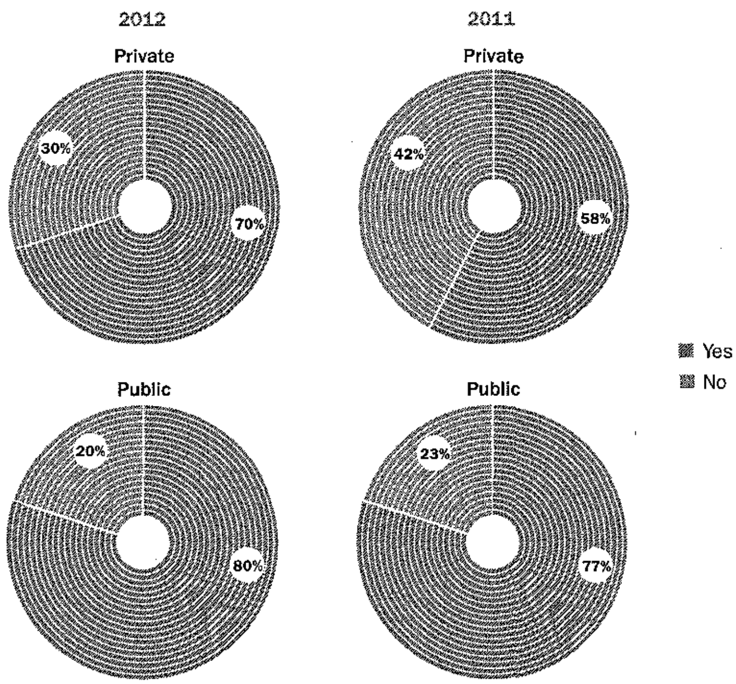
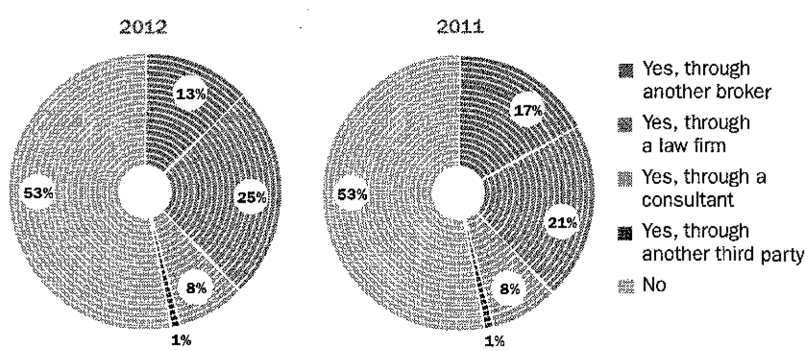


Figure 9. Prevalence of independent policy review
In the past two years, have you conducted an independent review of your D&O liability policy?



Policy Limits

The average total limits by asset size were $112.2 million for all size groups, excluding charities and nonprofits, and $98 million for all respondents *(Figure 10)*. Firms with total assets greater than $10 billion, our largest pool of respondents, maintained average limits of $182.1 million, with a median limit purchased of $165 million. Private organizations had an average $48.5 million limit for all size groups measured by total assets *(Figure 11)*, compared with $132.6 million (*Figures 12* and *13*) for public companies measured by both total assets and market capitalization. As the pool of respondents for private organizations is considerably smaller than the total number of our public company respondents, care should be taken when drawing conclusions from the data.

Figure 10. Total limits by asset size (in millions)

	Participants reporting	First quartile	Median	Third quartile	Average
Less than $250 million	**16**	**$ 3.5**	**$ 5.0**	**$ 10.0**	**$ 10.4**
$250 million to $999 million	**25**	**$ 20.0**	**$ 25.0**	**$ 45.0**	**$ 34.0**
$1 billion to $4.9 billion	**77**	**$ 45.0**	**$ 75.0**	**$100.0**	**$ 75.5**
$5 billion to $9.9 billion	**46**	**$ 85.0**	**$125.0**	**$150.0**	**$120.8**
$10 billion or more	**80**	**$122.5**	**$165.0**	**$225.0**	**$182.1**
All size groups, excluding charities and nonprofits	**255**	**$ 50.0**	**$100.0**	**$150.0**	**$112.2**
All groups (total respondents)	**316**	**$ 35.0**	**$ 75.0**	**$140.0**	**$ 98.0**

Figure 11. Total limits by asset size (in millions)
Private organizations only

	Participants reporting	First quartile	Median	Third quartile	Average
Less than $250 million	**12**	**$ 3.5**	**$ 5.0**	**$ 7.5**	**$ 8.7**
$250 million to $999 million	**12**	**$ 10.0**	**$ 17.5**	**$ 25.0**	**$ 18.8**
$1 billion to $4.9 billion	**20**	**$ 25.0**	**$ 35.0**	**$ 50.0**	**$ 41.3**
$5 billion to $9.9 billion	**3**	**$ 60.0**	**$ 75.0**	**$ 75.0**	**$ 70.0**
$10 billion or more	**8**	**$120.0**	**$150.0**	**$185.0**	**$148.1**
All size groups (private organizations only)	**62**	**$ 10.0**	**$ 30.0**	**$ 59.0**	**$ 48.5**

"As the pool of respondents for private organizations is considerably smaller than the total number of our public company respondents, care should be taken when drawing conclusions from the data."

The $132.6 million average total policy limit for public companies, not unexpectedly, was far higher than that of private companies. The average for public companies with $10 billion or more in asset size was $191.3 million, and $125.8 million for those in the $5 billion – $9.9 billion asset range (Figure 12). The top three respondent ranges based on market capitalization — $1 billion to $4.9 billion, $5 billion to $9.9 billion, and $10 billion or more — had total limits averaging $103.4 million, $149.8 million and $199.1 million, respectively (Figure 13).

Figure 12. Total limits by asset size (in millions)
Public organizations only

	Participants reporting	First quartile	Median	Third quartile	Average
Less than $250 million	**2**	**$ 20.0**	**$ 25.0**	**$ 30.0**	**$ 25.0**
$250 million to $999 million	**12**	**$ 40.0**	**$ 42.5**	**$ 50.0**	**$ 50.4**
$1 billion to $4.9 billion	**54**	**$ 60.0**	**$ 85.0**	**$105.0**	**$ 90.9**
$5 billion to $9.9 billion	**42**	**$100.0**	**$125.0**	**$150.0**	**$125.8**
$10 billion or more	**69**	**$125.0**	**$175.0**	**$225.0**	**$191.3**
All size groups (public organizations only)	**193**	**$ 75.0**	**$115.0**	**$175.0**	**$132.6**

Figure 13. Total limits by market capitalization
Public organizations only

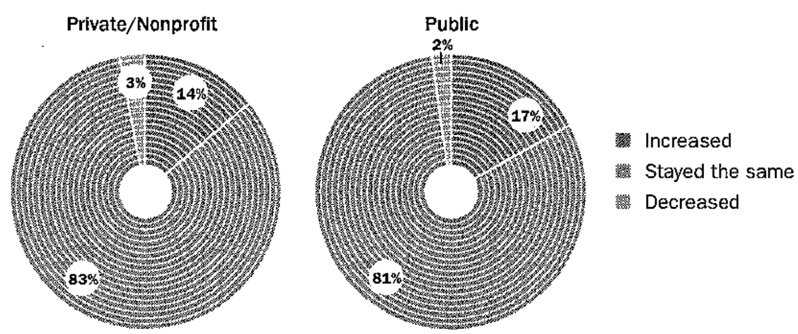
	Participants reporting	First quartile	Median	Third quartile	Average
Less than $250 million	**5**	**$ 30.0**	**$ 40.0**	**$ 50.0**	**$ 48.0**
$250 million to $499 million	**7**	**$ 40.0**	**$ 40.0**	**$ 80.0**	**$ 48.6**
$500 million to $999 million	**9**	**$ 45.0**	**$ 50.0**	**$ 75.0**	**$ 57.2**
$1 billion to $4.9 billion	**75**	**$ 70.0**	**$100.0**	**$130.0**	**$103.4**
$5 billion to $9.9 billion	**28**	**$ 87.5**	**$130.0**	**$205.0**	**$149.8**
$10 billion or more	**51**	**$125.0**	**$175.0**	**$250.0**	**$199.1**
All size groups (public organizations only)	**193**	**$ 75.0**	**$115.0**	**$175.0**	**$132.6**

Overall, more than 80% of organizations maintained the same D&O limits of liability at renewal *(Figure 15).* When compared to 2011, public companies participating in the survey were not as likely to increase the total limits of liability in their D&O programs: 17% indicated they increased their D&O insurance coverage, which represents a reduction from 25% when compared to the 2011 results. Consistent with last year, 14% of private/nonprofit organizations indicated that the limits in their D&O insurance program increased.

Figure 14. Total limits by business class

	Participants reporting	First quartile	Median	Third quartile	Average
Aerospace and Defense	5	$125.0	$130.0	$250.0	$185.0
Automobiles and Transport Equipment	4	$ 47.5	$102.5	$315.0	$181.3
Charities and Nonprofits	4	$ 12.5	$ 35.0	$ 50.0	$ 31.3
Communications	10	$ 50.0	$137.5	$160.0	$123.0
Energy and Utilities	40	$100.0	$142.5	$200.0	$152.3
Financial Services, excluding Insurance	20	$ 40.0	$ 95.0	$167.5	$109.3
Financial Services — Insurance	43	$ 20.0	$ 50.0	$ 75.0	$ 68.8
Food and Beverage	7	$ 30.0	$ 50.0	$125.0	$ 74.3
Government and Education	12	$ 7.5	$ 27.5	$ 45.0	$ 35.7
Health Care, excluding Pharmaceuticals	35	$ 25.0	$ 35.0	$ 50.0	$ 53.3
Health Care — Pharmaceuticals	5	$ 55.0	$125.0	$180.0	$112.0
High Technology	9	$ 80.0	$105.0	$150.0	$144.4
Manufacturing	65	$ 45.0	$ 90.0	$125.0	$104.0
Natural Resources	12	$ 80.0	$107.5	$175.0	$131.7
Professional and Business Services	10	$ 45.0	$ 52.5	$ 75.0	$ 60.5
Retail and Wholesale	15	$ 45.0	$100.0	$150.0	$101.3
Transportation	4	$ 42.5	$ 72.5	$ 77.5	$ 60.0
Other	16	$ 35.0	$ 82.5	$115.0	$ 81.3
All business classes (total respondents)	316	$ 35.0	$ 75.0	$140.0	$ 97.9

Figure 15. Change in total limits of liability in D&O insurance program
Compared to your previous D&O insurance program, have the total limits of liability in your D&O insurance program increased, decreased or stayed the same?



Primary D&O Program Structure

As in years past, the majority of participants in the 2012 survey (67%) reported a primary program structure inclusive of traditional Side A/B/C coverage. Seventeen percent of organizations conveyed a Side A/B structure. Once again, only 6% of respondents reported maintaining a Side A-only structure *(Figure 16)*.

Nonprofit (18%) and private organizations (17%) were also far more likely to respond that they were not sure how their primary D&O program was structured compared with their public company counterparts (3%) *(Figure 17)*. The 18% response from nonprofit participants represents a marked improvement over the 2010 and 2011 figures, suggesting that the nonprofit buyer is becoming more informed and involved in the D&O liability purchase.

A review of the premium paid for an organization's primary D&O policy clearly shows a firming marketplace for D&O coverage. Forty-one percent of private/nonprofit respondents experienced a premium increase in 2012, more than double the feedback received in 2011 (18%). A variety of factors are driving an insurer's need for pricing increases, including an uptick in D&O claim activity, ever-increasing employment litigation and inadequate pricing/retentions in the private/nonprofit space, to name a few. Nearly 30% of public companies indicated their premiums had increased, slightly more than double the 14% response in 2011. However, at the time the survey

Figure 16. Primary D&O insurance program structure
How is your *primary* D&O insurance program structured?

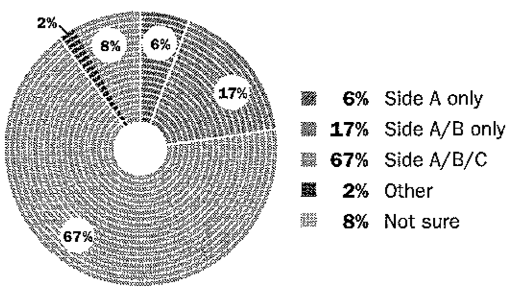


Figure 17. Primary D&O insurance program structure by ownership

	Participants reporting	Side A/B/C	Side A/B only	Side A only	Other	Not sure
Nonprofit	45	58%	13%	9%	2%	18%
Private	64	51%	25%	5%	2%	17%
Public	196	75%	14%	6%	2%	3%
All groups (total respondents)	325	67%	17%	6%	2%	8%

Figure 18. Change in premium paid for primary D&O policy
Compared to your previous *primary* D&O policy, did the premium paid for your *primary* insurance policy increase, stay the same or decrease?

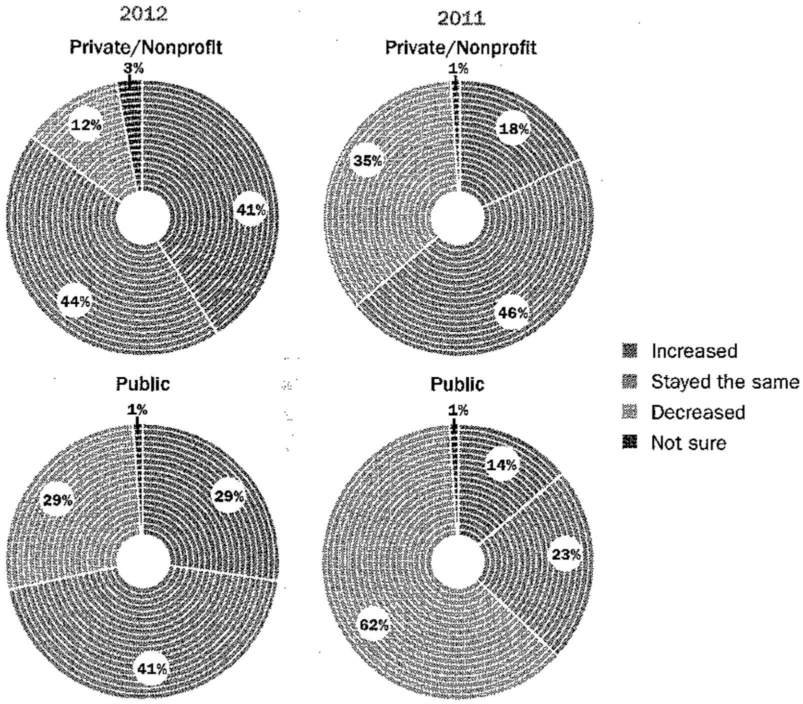


Figure 19. Primary D&O limit shared or blended with other coverages
Is your *primary* D&O limit shared or blended with other coverages (e.g., EPL, fiduciary)?

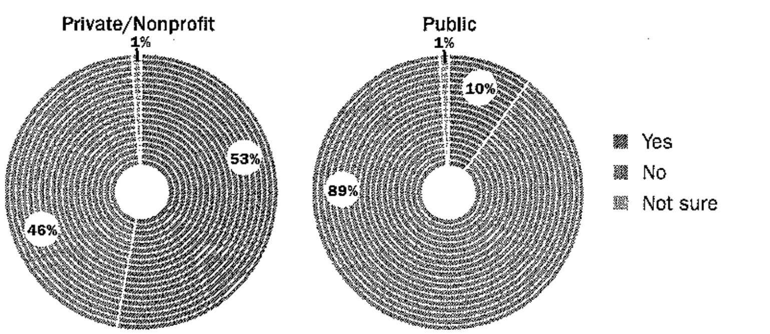
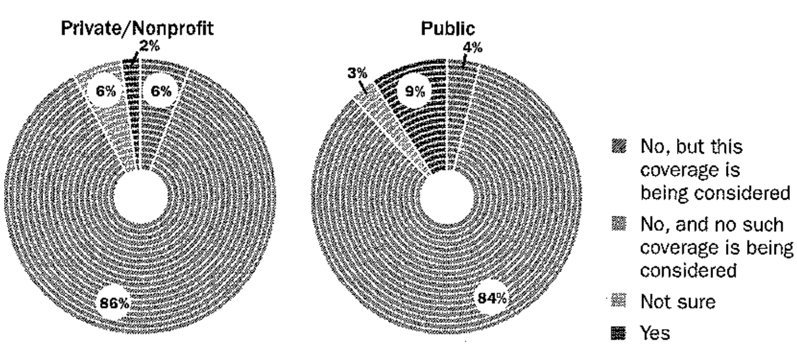
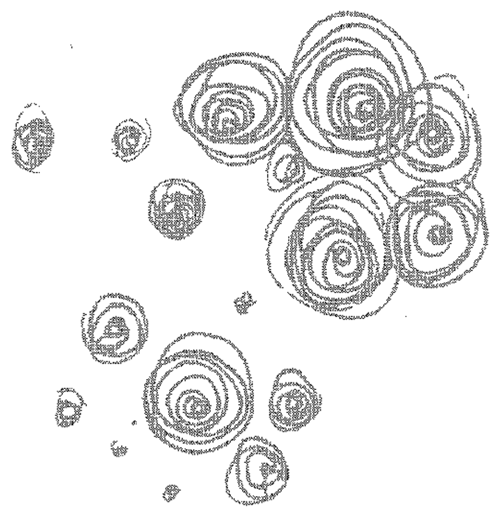


Figure 20. Independent directors liability
Does your organization purchase D&O liability insurance that covers *only* independent/outside (excluding inside) directors?



was taken, the market for public company D&O showed less pricing pressure, with an equal number of companies (29%) reporting a pricing decrease and increase *(Figure 18)*. As one would expect, the adequacy of the expiring pricing, the industry sector and the insured's loss history all come into play when a carrier assesses its need for a rate increase.

As expected, the vast majority of public companies (89%) do not share or blend their primary D&O limit with other coverages. This is in contrast to private/nonprofit respondents, which reported that 53% blended their D&O program with other coverages *(Figure 19)*. Approximately 85% of all respondents (private, nonprofit and public) currently do not purchase and do not plan to purchase D&O liability insurance that is dedicated solely to independent/outside directors. Less than 10% of public respondents purchased such coverage, which is consistent with years past *(Figure 20)*.



The scope of coverage afforded to directors continues to lead the way as the most important aspect of their D&O program: 71% for public companies and 50% for private/nonprofit companies. The scope of coverage for officers was also a major consideration, with 73% of public companies and 62% of private/nonprofits ranking it either first or second *(Figure 21)*.

Our survey also finds that the vast majority of participants (87%) purchase excess limits in addition to their primary D&O limit through at least one additional insurer *(Figure 22)*.

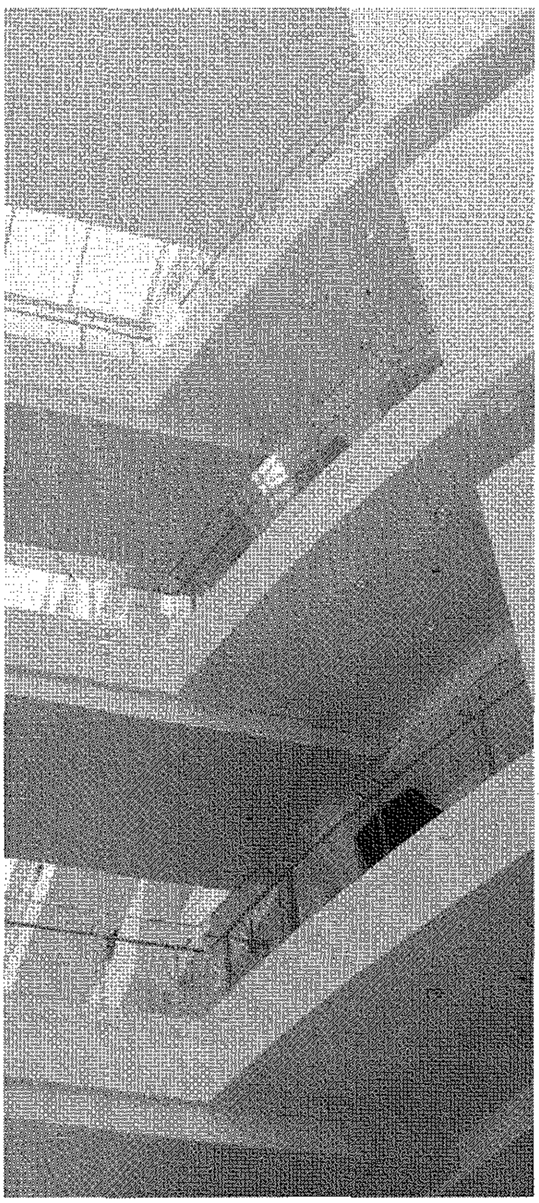


Figure 21. Most important aspects of D&O insurance coverage
Ranking for aspects of D&O insurance coverage on a scale of 1 to 4, where 1 is most important and 4 is least important (top three rankings)

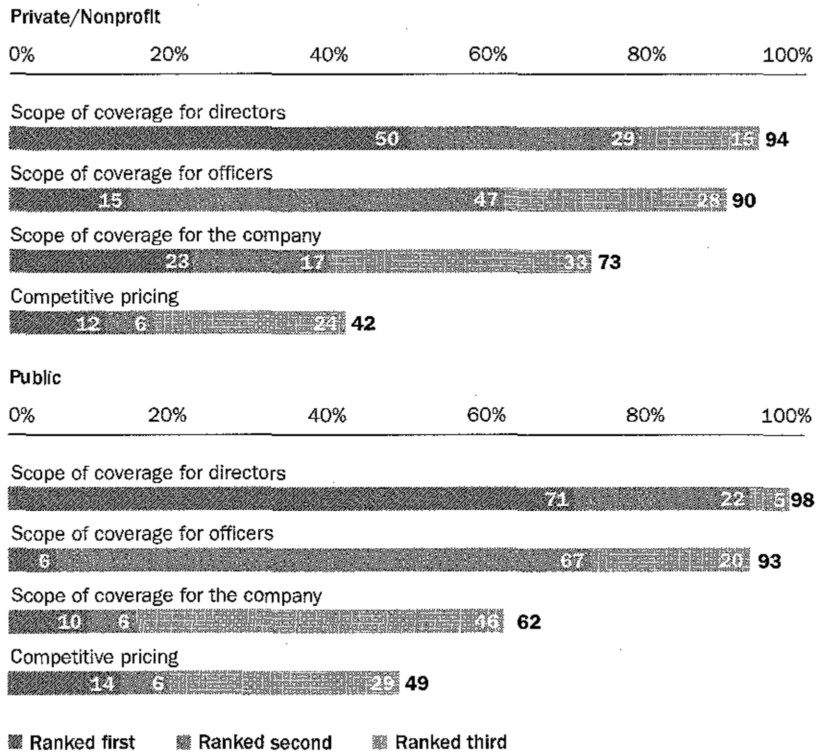
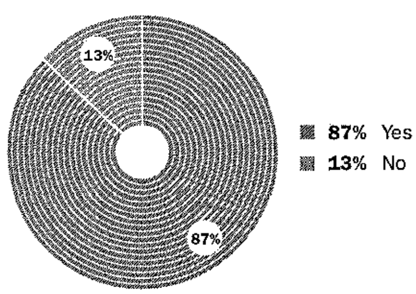
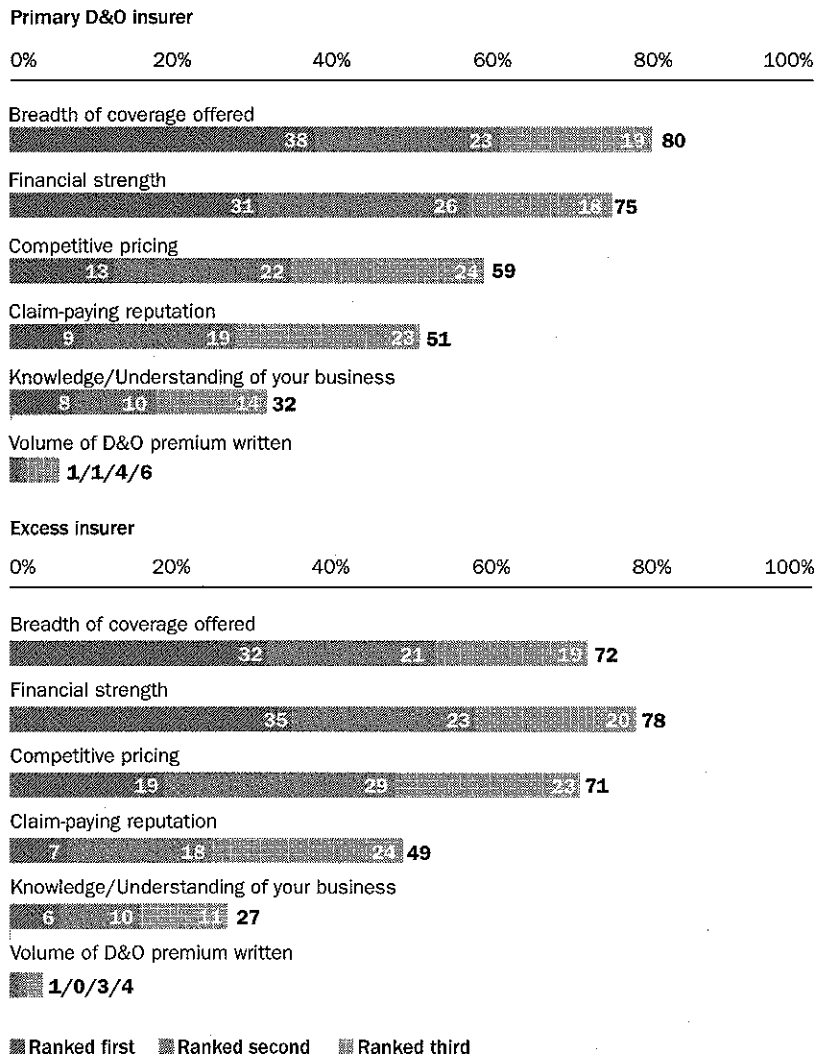


Figure 22. Excess limits
In addition to your *primary* D&O limit, are excess limits purchased through at least one additional insurer?



When asked to rank the importance of various characteristics of primary and excess D&O insurers, 38% of respondents rated breadth of coverage as the most important aspect of a primary D&O insurer. For excess insurers, the A.M. Best rating or financial strength was ranked most important by 35% of companies, edging out breadth of coverage at 32%. It is also important to note that our survey participants were not as price driven when compared to 2011, as there was more of a focus on the importance of coverage over pricing *(Figure 23)*.

Figure 23. Most important aspects of excess insurer versus *primary* D&O insurer
Rank the following aspects of your *excess* insurer on a scale of 1 to 6, where 1 is most important and 6 is least important (top three rankings).



"When asked to rank the importance of various characteristics of primary and excess D&O insurers, 38% of respondents rated breadth of coverage as the most important aspect of a primary D&O insurer."

Excess Side A Coverage

Public companies continue to consider excess Side A difference-in-condition (DIC) policies as an integral component of their organization's D&O program, as evidenced by the 83% of respondents that purchased such a policy. What also stands out is the increase in private organizations that maintain a dedicated Side A program as part of their D&O program. Forty-one percent of private company respondents purchased an excess Side A program *(Figure 24)*, an increase from 34% in 2011. Sixty-five percent cited breadth of coverage as the main impetus for driving the purchasing decision, a significant increase over the 45% response in 2010. Such a meaningful increase is further evidence of the product's heightened importance. Directors and officers feel the need for additional assurances beyond corporate indemnification. In fact, 43% of respondents indicated the need for added protection in the event their company becomes bankrupt and/or insolvent, up from 28% in 2010 *(Figure 25)*.

"Directors and officers feel the need for additional assurances beyond corporate indemnification. In fact, 43% of respondents indicated the need for added protection in the event their company becomes bankrupt and/or insolvent, up from 28% in 2010."

Figure 24. Excess Side A coverage
Did your organization purchase an excess Side A or Side A DIC policy?

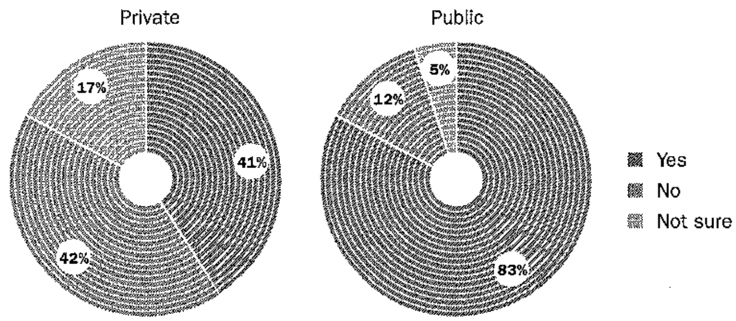


Figure 25. Impetus for purchase of excess Side A policy

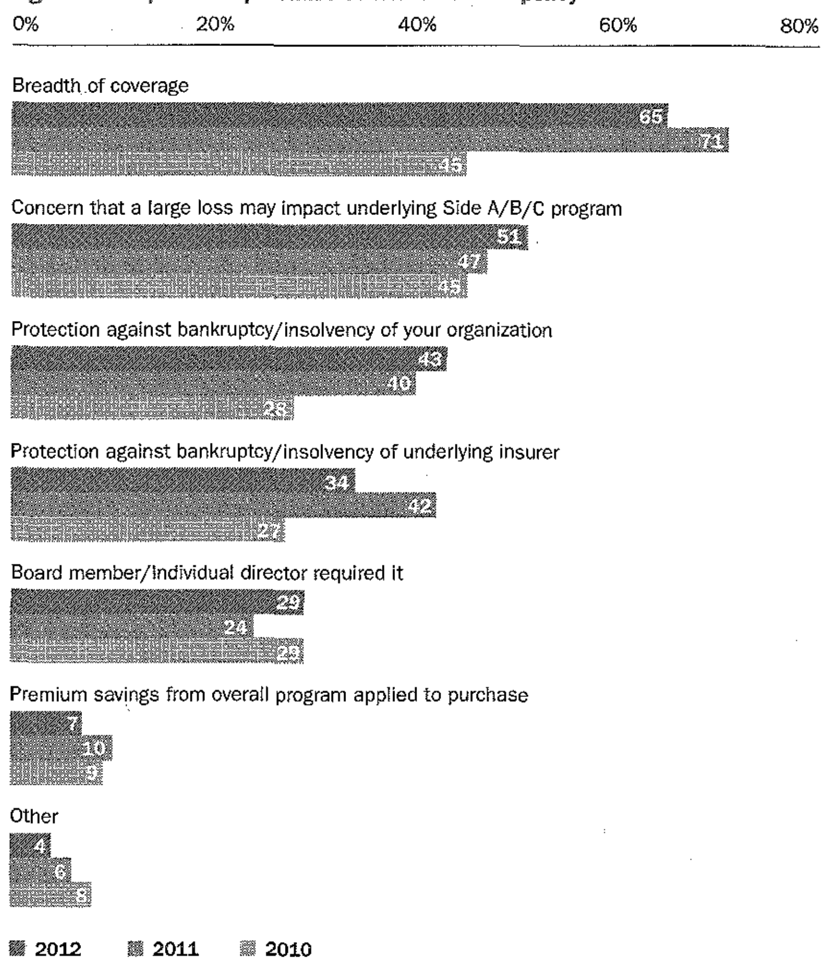


Figure 26. Excess Side A coverage by asset size
Private organizations only

	Participants reporting	Yes	No	Not sure
Less than $250 million	12	8%	67%	25%
$250 million to $999 million	12	25%	42%	33%
$1 billion to $4.9 billion	20	40%	45%	15%
$5 billion to $9.9 billion	3	67%	33%	0%
$10 billion or more	9	67%	22%	11%
All size groups (private organizations only)	64	41%	42%	17%

Figure 27. Excess Side A coverage by market capitalization
Public organizations only

	Participants reporting	Yes	No	Not sure
Less than $250 million	6	83%	0%	17%
$250 million to $499 million	7	57%	29%	14%
$500 million to $999 million	9	100%	0%	0%
$1 billion to $4.9 billion	76	80%	17%	3%
$5 billion to $9.9 billion	28	96%	4%	0%
$10 billion or more	51	86%	10%	4%
All size groups (public organizations only)	196	83%	12%	5%

Generally speaking, the larger the organization, the more likely it is to purchase Side A coverage. For private organizations specifically, two-thirds of firms with total assets in excess of $5 billion purchased excess Side A coverage. Conversely, over two-thirds (67%) of smaller firms with under $250 million in assets reported not doing so *(Figure 26)*. Again, more of the larger public companies purchased excess Side A coverage *(Figure 27)*.

For all respondents, the average amount of excess Side A limits purchased was $43.6 million. The largest average of $75.8 million was represented by companies with $10 billion or more in assets *(Figure 28)*. The average limit for all private organizations was more modest at $25.4 million *(Figure 29)*. When measured by market capitalization, the average for 162 public companies was $50.2 million, with larger companies ($10 billion or more, based on market capitalization) posting an average of $80.9 million in excess Side A limits purchased *(Figure 30)*.

Figure 28. Amount of excess Side A limits purchased by asset size (in millions)

	Participants reporting	First quartile	Median	Third quartile	Average
Less than $250 million	3	$ 2.0	$ 5.0	$ 10.0	$ 5.7
$250 million to $999 million	13	$10.0	$10.0	$ 10.0	$14.3
$1 billion to $4.9 billion	55	$10.0	$20.0	$ 35.0	$26.5
$5 billion to $9.9 billion	42	$20.0	$30.0	$ 50.0	$42.4
$10 billion or more	63	$25.0	$50.0	$100.0	$75.8
All size groups excluding charities and nonprofits	186	$15.0	$30.0	$ 50.0	$47.0
All groups (total respondents)	207	$15.0	$25.0	$ 50.0	$43.6

Figure 29. Amount of excess Side A limits purchased by asset size (in millions)
Private organizations only

	Participants reporting	First quartile	Median	Third quartile	Average
Less than $250 million	1	$ 2.0	$ 2.0	$ 2.0	$ 2.0
$250 million to $999 million	3	$ 1.0	$ 5.0	$ 10.0	$ 5.3
$1 billion to $4.9 billion	8	$10.0	$10.0	$ 17.5	$13.8
$5 billion to $9.9 billion	2	$10.0	$17.5	$ 25.0	$17.5
$10 billion or more	5	$50.0	$55.0	$100.0	$68.0
All size groups (private organizations only)	24	$ 7.5	$12.5	$ 32.5	$25.4

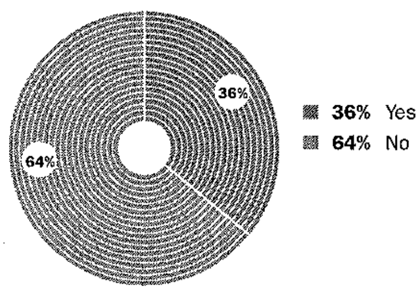
Figure 30. Amount of excess Side A limits purchased by market capitalization (in millions)
Public organizations only

	Participants reporting	First quartile	Median	Third quartile	Average
Less than $250 million	5	$10.0	$10.0	$ 10.0	$12.0
$250 million to $499 million	4	$10.0	$15.0	$ 25.0	$17.5
$500 million to $999 million	9	$10.0	$10.0	$ 25.0	$16.1
$1 billion to $4.9 billion	60	$20.0	$30.0	$ 50.0	$36.7
$5 billion to $9.9 billion	27	$25.0	$40.0	$ 70.0	$48.0
$10 billion or more	44	$25.0	$50.0	$105.0	$80.9
All size groups (public organizations only)	162	$20.0	$35.0	$ 55.0	$50.2

Claims

Thirty-six percent of respondents reported having had claims against their D&O liability policies in the last 10 years *(Figure 31)*, with nonprofits reporting the highest proportion of claims (63%) *(Figure 32)*. In our view, such a significant figure is noteworthy because it contradicts popular opinion that D&O claim activity is a public company phenomenon. To the contrary, directors and officers of public, private and nonprofit companies and their organizations all face the risk of litigation. Claims were most likely to be filed against larger firms with assets of $5 billion or more *(Figure 33)*. The biggest jump in claims in 2012 was brought about by regulatory

Figure 31. D&O claims in the last 10 years
Has your organization had any claims against its D&O liability policy during the last 10 years?



"In our view, such a significant figure is noteworthy because it contradicts popular opinion that D&O claim activity is a public company phenomenon. To the contrary, directors and officers of public, private and nonprofit companies and their organizations all face the risk of litigation."

Figure 32. D&O claims in the last 10 years by ownership

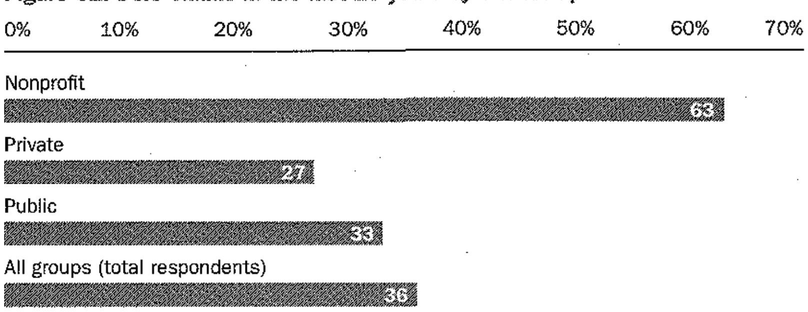
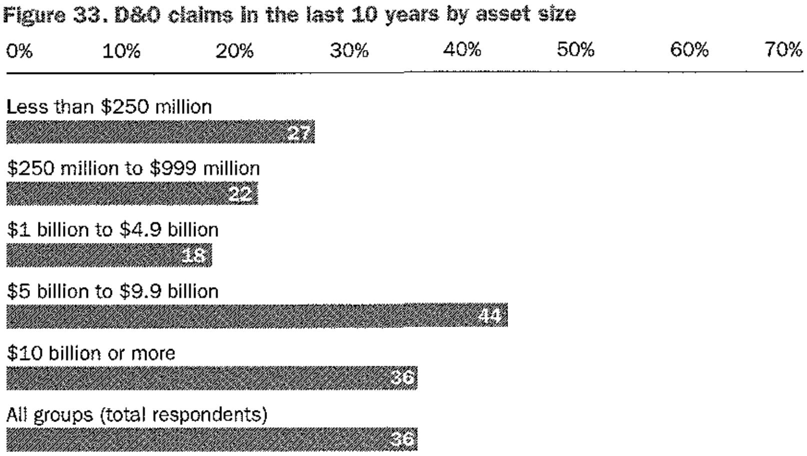
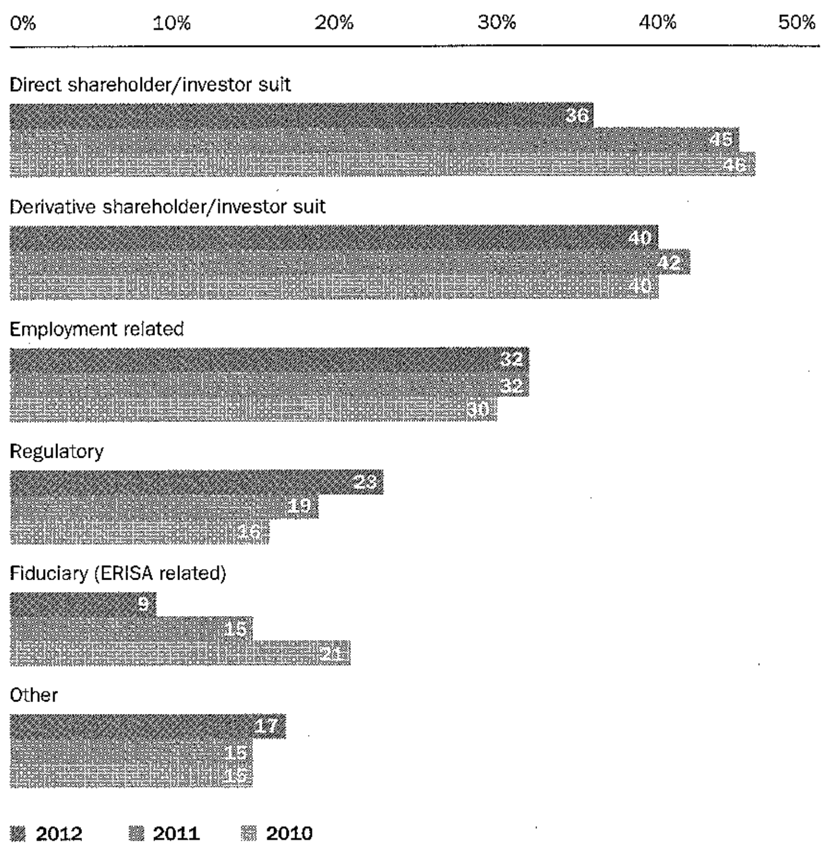


Figure 33. D&O claims in the last 10 years by asset size



actions, increasing to 23% of responses from 19% in 2011 and 16% in 2010 *(Figure 34)*. Consistent with our last three reports, derivative shareholder/investor suits and direct shareholder/investor suits continue to lead the types of claims filed over the last 10 years. Direct shareholder suits have trended downward, with derivative shareholder suits remaining relatively constant over the same period (Figure 34).

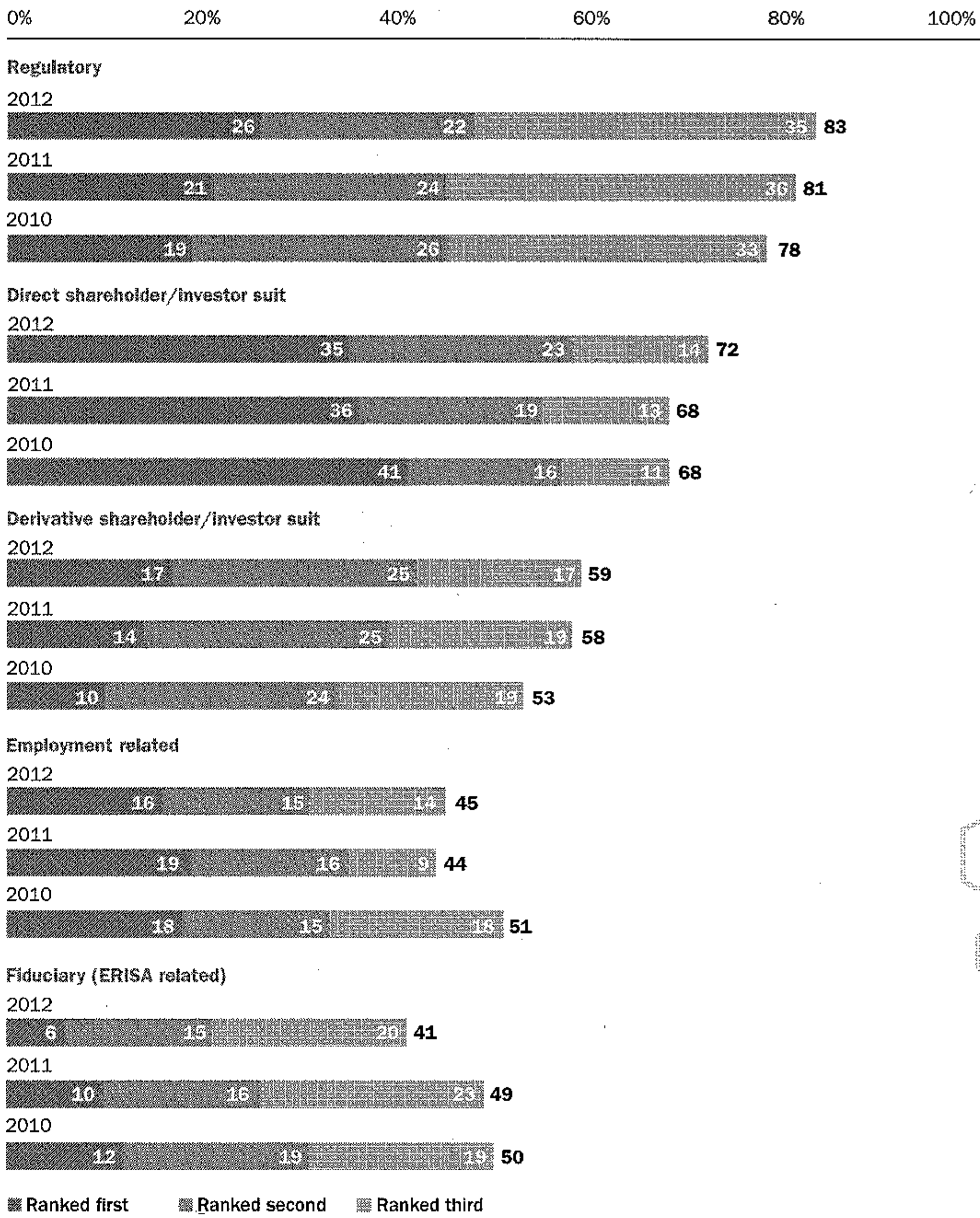
Figure 34. Types of claims in the last 10 years



Over the past three years, concerns over regulatory and derivative shareholder/investor lawsuits have trended upward, with 26% and 17%, respectively, ranking these as a top concern. Direct shareholder/investor suits still register the greatest concern among survey participants, but that concern has trended downward from 41% in 2010 to 35% in 2012 *(Figure 35)*. The increased concern over regulatory litigation may reflect new laws put in place since the financial crisis, including the Dodd-Frank Wall Street Reform and Consumer Protection Act, as well as an increase in whistleblower bounties.

Figure 35. Top D&O liability concerns

Ranking for the following types of claims on a scale of 1 to 5, where 1 is the greatest concern to the organization and 5 is the least concern (top three rankings)



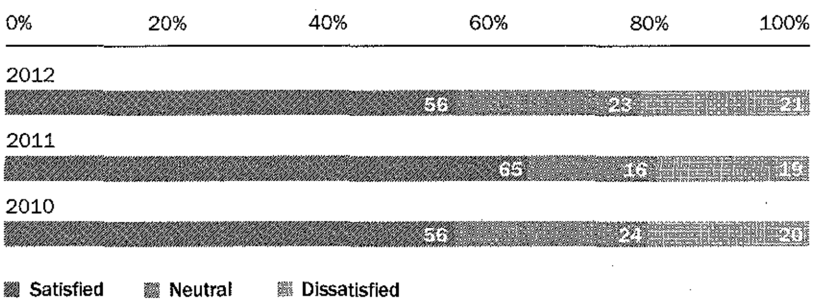
Of the respondents, employment-related claims over the last decade were most likely to be filed by nonprofits (85%) and private companies (38%), while public companies were most likely to face direct shareholder (57%) and derivative shareholder (64%) actions *(Figure 36).*

Over the past three years, of those respondents that experienced claim activity, approximately 80% were either satisfied or neutral with the handling of the claim *(Figure 37).* However, the very fact that approximately 20% of organizations remain dissatisfied with D&O claim-handling services speaks to a real need to take a more careful look at why respondents are dissatisfied. Reasons may be rooted in the complexities of the claim process or the need for better communication among all parties. The finding belies the relatively low importance placed on claim-paying reputation when compared with other aspects of companies' primary and excess insurers. Only 28% of participants ranked claim-paying reputation as first or second for a primary D&O insurer, with the percentage dropping to 25% for excess insurers (Figure 23, page 14).

Figure 36. Types of claims in the last 10 years by ownership

	Direct shareholder/ investor suit	Derivative shareholder/ investor suit	Employment related	Regulatory	Fiduciary	Other
Nonprofit	**4%**	**0%**	**85%**	**39%**	**8%**	**19%**
Private	**19%**	**25%**	**38%**	**19%**	**19%**	**25%**
Public	**57%**	**64%**	**7%**	**20%**	**8%**	**10%**
All groups (total respondents)	**36%**	**40%**	**32%**	**23%**	**9%**	**17%**

Figure 37. Satisfaction with handling of D&O claims
How satisfied were you with your D&O insurer's handling of the claim?



Appendix A

D&O Liability Survey — Insurance Market Summary

Company	Contact	Capacity	(in millions)	Comments
ABA Insurance Services, Inc.	Mike Read, Marketing & Sales Manager ABA Insurance Services, Inc. 5910 Landerbrook Drive, Suite 100 Mayfield Heights, OH 44124 800-274-5222 e-mail: mread@abais.com web: www.abais.com	2012	$15	Writes commercial banks and thrifts.
ACE				
ACE Bermuda	Jeffrey Jabon Senior Vice President Head of Professional Lines ACE Bermuda Insurance Ltd. 17 Woodbourne Avenue P.O. Box HM 1015 Hamilton HM 08 Bermuda 441-295-5200 e-mail: jeffrey.jabon@ace.bm web: www.acegroup.com or www.acebermuda.com	2012	$50	All segments and classes of business, including public, private, partnerships, sporting organizations, not-for-profit and financial institutions. Excess follow-form all lines (for A-Side, see CODA). Manuscript (bespoke) policies available for complex risk solutions. Bermuda representative and international brokers.
ACE International	Ben Ingram, Senior Vice President International D&O Product Manager Head of Financial Lines — Asia Pacific Nicholas Small Chief Underwriting Officer — Financial Lines ACE International ACE Building 100 Leadenhall Street London EC3A 3BP Ben: 61-2-9335-3462 Nick: 44-20-7173-7973 e-mail: ben.ingram@acegroup.com nick.small@acegroup.com web: www.aceltd.com	2012	$25	Writes international accounts, excluding U.S.-headquartered corporations, with a capacity of $25 million primary or excess. ACE will consider all classes of accounts, including financial institutions. Local underwriters and local language policy forms in most international countries.
ACE USA	Scott A. Meyer, President ACE Professional Risk 1133 Avenue of the Americas 32nd Floor New York, NY 10036 212-642-7880 212-703-7166 (fax) e-mail: scott.meyer@acegroup.com web: www.acegroup.com/us	2012	$25	All segments and classes of business, including public, private, not-for-profit and financial institutions. Retail brokers. Writes on Illinois Union paper.

Company	Contact	Capacity	(in millions)	Comments
AIG Financial Lines, a division of AIG	Louis S. Lucullo Head of Commercial Directors & Officers Liability Global Financial Lines 175 Water Street New York, NY 10038 212-458-3745 e-mail: Louis.Lucullo@aig.com web: www.aig.com Brian Benjamin Head of Financial Institutions Global Financial Lines 175 Water Street New York, NY 10038 212-458-3023 e-mail: Brian.Benjamin@aig.com web: www.aig.com	2012	$50	All classes. U.S. and Canada: Rob Yellen Chief Underwriting Officer Financial Lines, U.S. and Canada 212-458-3745 Brady Head Head of Public Company Management Liability 713-342-7573 Shelley Norman Head of Private and Nonprofit Management Liability 312-930-2460 David Lynders Head of Financial Institutions 212-458-2927 Europe: Peter McKenna Head of Financial Lines, Europe 44-20-7651-6394
AIG Cat Excess Liability, operating from branches in the U.S., Bermuda and London	William Hopkins Executive Vice President Product Line Manager AIG Cat Excess Liability 32 Old Slip, 19th Floor New York, NY 10005 646-857-1147 e-mail: william.hopkins@ chartisinsurance.com web: www.chartisinsurance.com	2012 Max available	$75	All industry classes. Full cover, Side A, Lead DIC U.S. domestic and international.
Chubb	Robert C. Cox Chief Operating Officer Chubb Specialty Insurance 3 Mountain View Road Warren, NJ 07059 908-903-2203 e-mail: rcox@chubb.com web: www.chubb.com	2012	$25	All classes. Chief Underwriting Officer is Michael J. Maloney, mmaloney@chubb.com; Specialty Products manager is Evan Rosenberg, erosenberg@chubb.com; contact for D&O is Tony Galban, galbant@chubb.com; contact for Health Care Institutions is Beth Strapp, strappb@chubb.com; contact for Financial Institutions is Rich Edsall, redsall@chubb.com; contact for Private is Lisa Jones, ljones@chubb.com; and contact for Not-for-Profit Companies is Michael Schraer, mschraer@chubb.com.

Company	Contact	Capacity	(in millions)	Comments
Cincinnati Insurance Co.	Scott Unger Vice President & Underwriting Manager Cincinnati Insurance Co. P.O. Box 145496 Cincinnati, OH 45250-5496 513-870-2407 e-mail: scott_unger@cinfin.com web: www.cinfin.com	2012	$10	D&O, Fiduciary, EPLI and Cyber (Blue Chip Policy). All classes written on Cincinnati Insurance Co. NOTE: Only available through our CIC agency force.
Alterra				
Alterra Bermuda Ltd.	Ben Munro, Senior Vice President Alterra Bermuda Ltd. Alterra House 2 Front Street Hamilton HM 11 Bermuda 441-296-8800 441-296-8811 (fax) e-mail: Ben.Munro@alterra-bm.com web: www.alterracap.com	2012 Side A	$25 $25	Excess AB, ABC, Side A and Side A DIC. No excluded classes.
Alterra USA	Daniel G. Gamble Executive Vice President Alterra USA 1185 Avenue of the Americas 16th Floor New York, NY 10036 212-898-6622 646-300-4104 (mobile) e-mail: daniel.gamble@alterra-us.com	2012	$25	All classes.
American Safety Insurance Services, Inc.	Peter McKeegan, Vice President Professional Liability Group 101 Hudson Street, Suite 3606 Jersey City, NJ 07302 201-830-2264 201-830-2279 (fax) e-mail: peter.mckeegan@amsafety.com web: www.amsafety.com	2012	$5 (D&O and E&O)	Primary or excess: D&O/EPL/Fiduciary — public, private, partnerships or nonprofit for virtually all classes other than financial institutions. Both standard and/or difficult to place risks considered. Miscellaneous professional, insurance agents and select lawyers, technology E&O and A&E are also available on both a primary and excess basis. Contact Vince McGee at vince.mcgee@amsafety.com for E&O products.
Arch Insurance				
Arch Insurance (U.S.)	John A. Rafferty One Liberty Plaza, 53rd Floor New York, NY 10006 646-563-6364 e-mail: jrafferty@archinsurance.com	2012	$25	All classes.

Company	Contact	Capacity	(in millions)	Comments
Arch Insurance Bermuda	Matt Smith, Vice President Underwriting Manager Executive Assurance Arch Insurance Bermuda 11 Victoria Street, 4th Floor Victoria Hall P.O. Box HM 129 Hamilton HM 11 Bermuda 441-278-9268 441-278-9276 (fax) e-mail: matt.smith@archinsurance.bm web: www.archinsurance.bm	2012	$25	All classes.
Arch — Homes and Services for the Aging	Jason Tharpe, Vice President Aon Association Services 1120 20th Street, NW, 6th Floor Washington, DC 20036-3406 202-429-8561 e-mail: Jason_tharpe@aon.com web: www.leadingageinsurance.com	2012	$5	MGA for Arch on nonprofit homes and services for the aging. This segment includes but is not limited to: assisted-living facilities, adult daycare, independent senior housing, skilled nursing facilities and continuing care retirement EPL, Fiduciary and Crime coverage parts.
Argo Pro	Laurie Banez, Senior Vice President Chief Underwriting Officer 101 Hudson Street, Suite 1201 Jersey City, NJ 07302 732-623-8966 lbanez@argoprous.com web: www.argolimited.com	2012	$15	Broad portfolio of management and professional liability products on a primary and excess basis.

Aspen Insurance Group	Fred Cooper
	Aspen Specialty
	101 Hudson Street, 36th Floor
	Jersey City, NJ 07302
	646-502-1022
	646-502-1020 (fax)
	e-mail: Fred.Cooper@
	Aspen-Insurance.com
	web: www.aspen.com
		2012	$25	• Commercial and financial institutions
				• Primary and excess
				  • D&O
				  • Side A
				  • Employment practices liability
				  • Fiduciary liability
				  • Private equity
				  • Private company coverage

AWAC				
AWAC US (Allied World Assurance Company, Ltd.)	Thomas Kennedy Allied World Assurance Company 199 Water Street, 24th Floor New York, NY 10038 646-794-0514 646-794-0611 (fax) e-mail: thomas.kennedy@awac.com web: www.awac.com	2012	$25	All classes.

Company	Contact	Capacity	(in millions)	Comments
AWAC Bermuda (Allied World Assurance Company, Ltd.)	Ed Moresco, Senior Vice President Bermuda & International Professional Liability Manager Allied World Assurance Company 27 Richmond Road P.O. Box HM 3010 Hamilton HM MX Bermuda 441-278-5401 e-mail: ed.moresco@awac.com web: www.awac.com	2012	$25	All classes.
Axis Capital				
AXIS Insurance	John Van Decker Executive Vice President North American Professional Lines AXIS Insurance 300 Connell Drive, Suite 8000 P.O. Box 357 Berkeley Heights, NJ 07922-0357 908-508-4367 908-508-4301 (fax) e-mail: john.vandecker@axiscapital.com web: www.axiscapital.com	2012	$25	D&O insurance and other professional lines coverage for publicly traded and privately held companies of all sizes. Commercial accounts, financial institutions and not-for-profit organizations. U.S. underwriting companies include AXIS Insurance Company, AXIS Reinsurance Company and AXIS Surplus Insurance Company. In the U.S., contact John Van Decker, head of North American Professional Lines, john.vandecker@axiscapital.com or 908-508-4367. Outside the U.S., contact Graham Evans, head of International Professional Lines, graham.evans@axiscapital.com or +44 207 877 3880. Key business unit contacts: edward.talarico@axiscapital.com for AXIS Financial Insurance Solutions (U.S.); timothy.braun@axiscapital.com for AXIS Financial Institutions (U.S.); hillary.williams@axiscapital.com in Bermuda; and dax.qulmohamed@axiscapital.com in London.
Professional Risk Facilities, Inc.	Stephen Cavallaro, Underwriting Manager Professional Risk Facilities, Inc. 113 South Service Road Jericho, NY 11753 516-408-5736 516-747-6074 (fax) e-mail: scavallaro@professionalrisk.com web: www.professionalrisk.net	2012	$5	All classes except financial institutions and public companies. Underwriting manager/program administrator for CNA, utilizing CNA's Epack and Epak Extra policy forms (D&O, EPL, Fiduciary, MPL, Crime, and Technology & Privacy Liability), which is admitted in all 50 states and written on Columbia Casualty Company paper. Coverage is also available for not-for-profit organizations.

Company	Contact	Capacity	(in millions)	Comments
Beazley Group plc	Neal Wilkinson, Specialty Lines Beazley Group – London Plantation Place South 60 Great Tower Street London, EC3R 5AD 44-20-7667-0623 44-20-7674-7100 (fax) e-mail: neal.wilkinson@beazley.com web: www.beazley.com Marc London, Specialty Lines Beazley Group – USA 1270 Avenue of the Americas Suite 1200 New York, NY 10020 646-943-5900 646-378-4039 (fax) e-mail: marc.london@beazley.com web: www.beazley.com	2012	$20	Primary or excess for commercial risks. Issuing company: Beazley Insurance Company, Inc. (option for non-admitted paper Syndicate 2623/623 at Lloyd's). Beazley also offers foreign Side A D&O coverage for U.S.-based multinational corporations through Beazley Bridge product, D&O for health care organizations, Fiduciary Liability, Employment Practices Liability and Crime coverage.
Catlin, Inc.	Catherine Cossu Catlin, Inc. Financial Square 32 Old Slip, 36th Floor New York, NY 10005 212-801-3400 e-mail: catherine.cossu@catlin.com David McDonald James Thomas Catlin US 60 State Street, Suite 1250 Boston, MA 02109 617-316-1207 e-mail: david.mcdonald@catlin.com jim.thomas@catlin.com Stephen McGill Michael Scarlata Catlin US 5700 Canoga Avenue, Suite 130 Woodlands Hills, CA 91367 818-577-4100 e-mail: stephen.mcgill@catlin.com michael.scarlata@catlin.com	2012	$15	All classes — both primary and excess. Catlin Insurance Company Inc. and Catlin Specialty Insurance Company.

Company	Contact	Capacity	(in millions)	Comments
CNA				
CNA Pro	Daniel Fortin, Senior Vice President CNA 333 S. Wabash, 35th Floor Chicago, IL 60604 312-822-5177 e-mail: daniel.fortin@cna.com web: www.cnapro.com	2012 Side A	$15 $25	All classes. Contact is Joe Kelly 312-822-4409 for all not-for-profit, middle market and private businesses. Contact for financial institutions is Thomas Kocaj. Contact for public commercial firms is Thor Beveridge.
CNA – Nonprofit Community Homeowner Associations	Adam S. Collins, CIC Assistant Vice President Ian H. Graham Insurance 15303 Ventura Boulevard, 12th Floor Sherman Oaks, CA 91403 818-742-1429 312-381-0593 (fax) e-mail: adam.collins@ianhgrahaminc.com web: www.ihginsurance.com	2012	$5	MGA for CNA. D&O for nonprofit community homeowner associations, condo associations, commercial associations, timeshares, co-ops, property owners associations and planned urban developments.
Crum & Forster	Gary Dubois, President Management and Professional Services Crum & Forster Management and Professional Services Divisions 305 Madison Avenue Morristown, NJ 07960 973-490-6600 973-490-6965 (fax) e-mail: gary.dubois@cfins.com web: www.cfins.com	2012	$10	Primary or excess: D&O/EPL/ Fiduciary — public, private or nonprofit, for virtually all classes. Standard and/or difficult to place risks. Lawyers Professional Liability, Accountants Professional Liability, Crime, Miscellaneous Professional Liability, Cyber-Liability and Technology E&O are also available.

Company	Contact	Capacity	(in millions)	Comments
CODA				
(Corporate Officers & Directors Assurance)	Jeffrey Jabon Deputy Chairman Senior Vice President Head of Professional Lines ACE Bermuda Insurance Ltd. 17 Woodbourne Avenue P.O. Box 1015 Hamilton HM 08 Bermuda 441-295-5200 e-mail: jeffrey.jabon@acegroup.bm web: www.acegroup.com or www.acebermuda.com	2012	$75	All segments and classes of business, including public, private, partnerships, sporting organizations, not-for-profit and financial institutions. Side A/DIC (Difference-in-Conditions, "drop-down" cover), Premier Personal Asset Protection for Directors & Officers (no Corporate Reimbursement) as well as Corporate Governance exposure coverage for Independent Directors, Executive Officers Only coverage, and Retiring(ed) Director & Officer coverage; all for non-indemnified risks, global or otherwise. Manuscript (bespoke) policies available for complex risk solutions. No minimum attachment, primary A-Side can be stand-alone or unique policy architecture can be structured to sit parallel to B/C cover and applicable retention-allowing CODA's broad A-Side coverage to be expanded upwards throughout follow-form tower. Bermuda representative and international brokers.
Westchester Specialty	Joseph Casey, President Professional Risk ACE Westchester Specialty 500 Colonial Center Parkway #200 Roswell, GA 30076 678-795-4258 678-795-4150 (fax) e-mail: joseph.casey@acegroup.com web: www.acewestchester.com	2012	$25	All classes. Wholesale brokers.
AEGIS	Karen P. Larson, Vice President AEGIS Insurance Services, Inc. 1 Meadowlands Plaza E. Rutherford, NJ 07073 201-508-2804 e-mail: karenlarson@aegislimited.com web: www.aegislimited.com	2012	$35	Utilities, energy, related energy and public power.

Company	Contact	Capacity	(in millions)	Comments
Endurance				
Endurance Risk Solutions (Bermuda)	Forbes Geekie, Senior Vice President Endurance Risk Solutions (Bermuda) Wellesley House, 90 Pitts Bay Road Pembroke HM 08 Bermuda 441-278-0434 e-mail: fgeekie@endurance.bm web: www.endurance.bm	2012	$25	Full range of Management and Professional Liability products for *Fortune* 1000 publicly traded and private commercial companies, financial institutions and law firms.
Endurance Risk Solutions, US	Raymond O'Byrne, Senior Vice President Endurance Risk Solutions 750 Third Avenue New York, NY 10017 212-209-6533 e-mail: robyrne@enhinsurance.com web: www.endurance.bm	2012	$25	D&O, EPLI, Fiduciary and Crime on a stand-alone or blended basis. All classes except financial institutions (other than REITs).
Energy Insurance Mutual	Jill Dominguez, ARM Vice President, Chief Underwriting Officer Energy Insurance Mutual 3000 Bayport Drive, #550 Tampa, FL 33607-8412 800-446-2270 or 813-287-2117 e-mail: jdominguez@eimltd.com web: www.eimltd.com	2012	$50	Industry mutual for utilities and energy services industries. NOTE: Minimum attachment point is $35 million.
Euclid Executive Liability Managers	Jim Seymour 234 Spring Lake Drive Itasca, IL 60044 630-694-3700 e-mail: jseymour@euclidexec.com web: www.euclidexec.com	2012	$5	Capacity in 2013 is $10 million.
Fireman's Fund	Bruce R. Bahn, Senior Product Director Professional Liability Fireman's Fund, Special Risk Division 33 West Monroe Street Chicago, IL 60603 312-456-5028 877-792-2242 (fax) 847-372-3565 (mobile) e-mail: bruce.bahn@ffic.com web: www.ffic.com	2012	$10	Primary coverage for multiline programs. Private company or nonprofit only.
Great American	Jonathan G. Starck Vice President Marketing Executive Liability Division Great American 1515 Woodfield Road, Suite 500 Schaumburg, IL 60173 630-897-4299 e-mail: jstarck@gaic.com web: www.GreatAmericanELD.com	2012	$25	All classes.

Company	Contact	Capacity	(in millions)	Comments
The Hartford				
Hartford Financial Products	Steven Boughal, Vice President & Chief Underwriting Officer Hartford Financial Products 277 Park Avenue, 15th Floor New York, NY 10172 212-277-0436 e-mail: steven.boughal@thehartford.com	2012	$25	All classes.
The Hartford – Nonprofits	Jason Tharpe, Vice President Aon Association Services 1120 20th Street, NW, 6th Floor Washington, DC 20036-3406 202-429-8561 e-mail: Jason_tharpe@aon.com web: www.nonprofitinsurancesolutions.com	2012	$10 for most classes of nonprofit organizations, except homes and services for the aging	MGA for Hartford Financial Products on Nonprofit D&O. Nonprofit classes included but not limited to social service organizations, trade and professional associations, foundations, museums and chambers of commerce. The Nonprofit D&O form has the ability to include D&O, EPL, Fiduciary and Crime coverage parts.
HCC Insurance Holdings				
HCC Global Financial Products	Andrew G. Stone, President HCC Global Financial Products 8 Forest Park Drive Farmington, CT 06032 860-674-1900 e-mail: astone@hcc-global.com Brian Hickey Senior Vice President HCC Global Financial Products 37 Radio Circle Drive P.O. Box 5000 Mt. Kisco, NY 10549-5000 914-242-7808 e-mail: bhickey@hcc-global.com web: www.hcc-global.com	2012	$25	All classes. Uses U.S. Specialty Insurance and Houston Casualty Insurance paper. International business contacts are Thibaud Hervy, CEO and Philippe Vezio, CEO, Spain (34-93-530-7300).
Hiscox Inc.	Bertrand Spunberg Senior Vice President Management Liability Hiscox USA 520 Madison Avenue New York, NY 10022 646-442-8322 617-515-2361 (mobile) e-mail: Bertrand.Spunberg@Hiscox.com web: www.hiscoxusa.com	2012	$15	Primary and excess not-for-profit and private company management liability products including D&O, EPLI, Fiduciary, Crime, Employed Lawyers, Kidnap and Ransom as well as Public Officials liability. Coverage offered to most classes of business regardless of size. Licensed or admitted in all states. Admitted primary and excess policies written through Hiscox Insurance Company. Surplus lines primary and excess written on Lloyd's paper.

Company	Contact	Capacity	(in millions)	Comments
Hudson Insurance Group (Odyssey Re)	Jim Hooghuis, Chief Underwriting Officer Hudson Financial Products 100 William Street New York, NY 10038 212-978-2807 e-mail: jhooghuis@hudsoninsgroup.com web: www.hudsoninsgroup.com	2012 Side A	$10 ABC $15	Private/Public Management Liability Products including: Primary, excess and Side A D&O policies for most public company classes including commercial and financial risks of all sizes, REITs and IPOs. Packaged primary (D&O/EPL/Fiduciary/Crime), excess and Side A policies for private and not-for-profit entities for most classes including health care.
ICI Mutual Insurance Co.	John T. Mulligan, Senior Vice President Chief Underwriting Officer ICI Mutual Insurance Group 1401 "H" Street NW Washington, DC 20005 800-643-4246 202-682-2425 (fax) e-mail: mulligan@icimutual.com	2012	$200	Group captive formed by mutual funds and investment advisors. Sponsored by the Investment Company Institute.
IronPro	Greg Flood, President IronPro One State Street, 7th Floor New York, NY 10004 646-826-6710 646-884-1729 (fax) e-mail: greg.flood@ironshore.com web: www.ironshore.com	2012 Side A	$15 $25	D&O all classes and ancillary PTL/EPLI/Fidelity/E&O.
Liberty				
Liberty Insurance Underwriters, Inc./Liberty Mutual Group	Kenia Delgado, Director Dual Specialty Underwriters 6915 Red Road, Suite 226 Coral Gables, FL 33143 786-275-3258 786-513-2678 (fax) e-mail: kdelgado@dualsu.com web: www.dualsu.com	2012	$10	MGA for Liberty Insurance Underwriters, Inc. Private company business with total assets of up to $250 million. D&O/EPL/Fiduciary/Crime/K&R.
Liberty Mutual Group/ Liberty International Underwriters	Trevor Howard, Senior Vice President Management Liability Liberty International Underwriters 55 Water Street New York, NY 10041 212-208-4139 212-208-2866 (fax) e-mail: Trevor.Howard@Libertyiu.com web: www.liiu-usa.com	2012	$25	Primary and excess management liability products for firms of all sizes, including public D&O, private D&O and not-for-profit D&O; financial institutions D&O/E&O; International D&O; REITs; Private Equity/Venture Capital; Employment Practices Liability; Pension Trust/Fiduciary Liability; Fidelity coverage.

Company	Contact	Capacity	(in millions)	Comments
Markel Insurance Company	Salvatore Pollaro, Managing Director Management Liability Markel Insurance Company 708 Third Avenue New York, NY 10017 212-551-2281 e-mail: spollaro@markelcorp.com web: www.markelcorp.com	2012	$10	Target market: private companies & not-for-profit organizations up to $750 million in annual revenues on a primary and excess basis: EPL, D&O, Fiduciary. Publicly traded companies up to $2 billion in market capitalization on an excess basis: EPL, D&O, Fiduciary. All classes eligible except financial institutions. Admitted and surplus paper available.
Monitor Liability Managers, LLC	Randy Mrozowicz Executive Vice President – Underwriting Monitor Liability Managers, LLC 2850 W. Golf Road, Suite 800 Rolling Meadows, IL 60008-4039 847-806-6590 ext. 531 e-mail: rmrozowicz@monitorliability.com web: www.monitorliability.com	2012	$10 (public company) $5 (private company) $5 (nonprofit)	Primary, excess and Side A with DIC for public companies. All classes except financial institutions, insurance companies and securities broker/dealers. Public and private companies and nonprofit organizations, primary and excess. All products offer EPLI. All A+ rated W.R. Berkley member company carriers. Issuing paper: Admiral Insurance Company, Berkley Insurance Company and Carolina Casualty Insurance Company. Public D&O contact is Joe Haltman 847-806-6590, ext. 532; private company and nonprofit contact is Tom Mathias 847-806-6590, ext. 510.
Navigators				
Navigators Insurance Company/ Navigators Specialty Insurance Company/Navigators Syndicate 1221 at Lloyd's of London	Christopher Duca, President Navigators Pro One Penn Plaza, 32nd Floor New York, NY 10119 212-613-4305 212-613-4302 (fax) e-mail: cduca@navg.com web: www.navg.com	2012	$25	All classes. D&O and EPL for publicly traded and privately held firms worldwide. D&O contact is Steven Kuuskvere at skuuskvere@navg.com or 212-613-4208. International D&O contact is Carl Bach, III at cbach@navg.com or 011-44-20-7220-6976.
Old Republic	Martin Perry, President Chicago Underwriting Group 191 North Wacker Drive, Suite 1000 Chicago, IL 60606-1905 312-750-8800 e-mail: mperry@cug.com web: www.cug.com	2012 Side A	$14 $25	All classes. Interested in technology, life science and commercial accounts on a primary basis. Those classes and all other for-profit entities considered on excess or Side A basis.

Company	Contact	Capacity	(in millions)	Comments
OneBeacon Professional Insurance	John Chace, Senior Vice President Chief Underwriting Officer OneBeacon Professional Insurance 199 Scott Swamp Road Farmington, CT 06032 860-321-2555 860-321-2890 (fax) 860-543-4743 (mobile) e-mail: JChace@OneBeaconPro.com Stacy Paquet, Vice President Management Liability 125 S. Wacker Drive, 12th Floor Chicago, IL 60606 212-440-6521 917-828-2228 (mobile) e-mail: SPaquet@OneBeaconPro.com web: www.onebeaconpro.com	2012	$20	D&O and related lines as follows: Health care D&O — hospitals, managed care, long-term care, medical facilities. Not-for-profit — education, social, etc. Private company — small and large (up to $10 million capacity).
Philadelphia Insurance Companies	Thomas R. Herendeen, RPLU, AFSB Vice President, Underwriting Management and Professional Liability One Bala Plaza, Suite 100 Bala Cynwyd, PA 19004 610-617-7623 610-227-0027 (fax) e-mail: therendeen@phlyins.com web: www.phly.com	2012	$20	Coverage available for nonprofit organizations and private commercial companies. Write both primary and excess. A.M. Best rating has increased to A++.
RLI Insurance Company	Chad Berberich, Vice President RLI Executive Products Group 909 Lake Carolyn Parkway, Suite 800 Irving, TX 75039 972-677-2116 e-mail: chad.berberich@rlicorp.com	2012	$25	All classes.
RSUI Group	Michelle Eason, Senior Vice President RSUI Group 945 East Paces Ferry Road, Suite 1890 Atlanta, GA 30326 404-504-3765 e-mail: meason@rsui.com web: www.rsui.com	2012	$20	All classes. Company is admitted in 50 states and uses RSUI Indemnity (admitted) paper and Landmark American (non-admitted) paper. Contact person for nonprofit is Amy Harrison. Subsidiary of Allegheny Corp. Contact person for private company business is Michelle Eason.

Company	Contact	Capacity	(in millions)	Comments
Sargasso Mutual Insurance Companies	Wanette M. Vann, Underwriter Sargasso Mutual Insurance Company, Ltd. Victoria Hall, 11 Victoria Street Hamilton HM 11 Bermuda 441-298-6620 e-mail: wanette.m.vann@marsh.com	2012 Primary Excess Side A Only	 $15 $15 $15	$15 million primary or excess Side A & B. $15 million excess Side A only. Coverage is available to eligible U.S.- or Canadian-domiciled life insurance companies. NOTE: managed by Marsh IAS Management Services (Bermuda) Ltd.
Scottsdale (Nationwide)				
Freedom Specialty	Craig Landi, Senior Vice President Freedom Specialty 7 World Trade Center New York, NY 10007 212-329-6901 e-mail: craig.landi@ freedomspecialtyins.com web: www.freedomspecialtyins.com	2012	$20	All classes of D&O and related lines of business.
Starr Indemnity & Liability Company	Jim Pittinger Vice President, Financial Lines Division Manager Starr Indemnity & Liability Company 399 Park Avenue, 8th Floor New York, NY 10022 646-227-6573 917-375-1141 (mobile) e-mail: james.pittinger@ starrcompanies.com web: www.starrcompanies.com/index.php/coverages/financial-lines	2012	$15	Primary and excess; public, private and not-for-profit; commercial and financial institutions.

Company	Contact	Capacity	(in millions)	Comments
Torus US Services Inc.	Jeffrey Grange, Senior Vice President Head of Management Liability & Professional Lines Torus Insurance 5 Harborside Plaza, Suite 2600 Jersey City, NJ 07311 201-830-2534 e-mail: jgrange@torus.com web: www.torus.com	2012	$10	Management Liability products offered: D&O, EPL, Fiduciary and Excess Crime for public, private, nonprofit and financial institution risks. Target classes: consumer products, services, manufacturers, aerospace, defense contractors, transportation, energy, natural resources, utilities, hospitality, oil & gas refiners, technology and specialty retail, all private companies, not-for-profit, service providers, media/entertainment, technology, private equity, venture capital, private fund, REITs, mutual funds, investment advisors, family officers and broker-dealers, banks and insurance companies. Opportunistic classes: homebuilders, pharmaceuticals, life sciences, education, municipal/government, casinos, construction, telecommunication, collection agencies, title agents, country clubs, day-care centers, firearms, insurance agents/brokers, real estate agents/brokers, alcohol distillers & tobacco manufacturers, investment banks, mortgage brokers/bankers, workers compensation insurers, bond insurers.

Company	Contact	Capacity	(in millions)	Comments
Travelers				
Travelers	Shanda Davis, Public D&O Product Manager Bonds & Financial Products Travelers One Towers Square Hartford, CT 06183 e-mail: srdavis@travelers.com web: www.travelers.com/business-insurance/management-professional-liability	2012	$25	Considers all classes; primary and excess. Public company liability contact is Bryan Kocon 678-317-7892; contact for private and nonprofit business is Peter Herron 860-277-1961; contact for financial institutions is Kristin Roger 860-277-8553. Issuing paper includes: Travelers Casualty and Surety Company of America, Travelers Excess and Surplus Lines Company, St. Paul Mercury and St. Paul Surplus Lines.
G.J. Sullivan Co.	Paul Bubnis, Vice President G.J. Sullivan 625 The City Drive, Suite 400 Orange, CA 92868 714-621-2340 e-mail: BubnisP@es.gjs.com web: www.gjsullivan.com	2012	$25	Managing General Underwriter for the Travelers Wrap+® for Health Care Organization Directors, Officers and Trustees Liability and Health Care Organization Employment Practices Liability products.
Western World Insurance Company	Gregg C. Rentko, CPCU, AU, MSIM Second Vice President, Brokerage Division Western World Insurance Company 400 Parson's Pond Drive Franklin Lakes, NJ 07417 201-847-2820 e-mail: g.rentko@westernworld.com web: www.westernworld.com	2012	$5	Tudor Pro and Tudor Specialty Liability have been merged to form Western World Brokerage-Professional, which is responsible for underwriting all open brokerage professional and management lines. While the lead line remains Nonprofit D&O, Brokerage-Professional is increasing its focus on Private Company, Municipal and School Board Legal Liability. Management Liability is now written on Western World Insurance Company paper in all states, except New York (Tudor).

Company	Contact	Capacity	(in millions)	Comments
United Educators Insurance, A Reciprocal Risk Retention Group	Bryan S. Elie, Vice President, Underwriting United Educators Insurance RRG Two Wisconsin Circle, 4th Floor Chevy Chase, MD 20815-9913 301-907-4908 ext. 426 e-mail: belie@ue.org web: www.ue.org	2012	$25	Risk Retention Group for universities, colleges, non-public elementary and secondary schools. Write educators legal liability. In addition, write public K-12 but only for limits up to $10 million.
W.R. Berkley (Berkley Professional Liability, LLC)	Paul A. Brophy, Senior Vice President Berkley Professional Liability, LLC 14 Wall Street New York, NY 10005 212-618-2903 212-618-2940 (fax) e-mail: pbrophy@berkleypro.com web: www.berkleypro.com	2012 Side A	$25 $25	All classes of D&O and related lines of business.
XL Insurance				
XL Insurance (Bermuda) Ltd.	Matthew G. Irvine Senior Vice President and CUO XL Insurance (Bermuda) Ltd. Brian O'Hara House One Bermuda Road Hamilton HM 08 Bermuda 441-294-7378 e-mail: Matthew.Irvine@xlgroup.com web: www.xlcapital.com	2012	$50	All classes. Side A can be written on a primary, excess or excess/DIC basis. Minimum attachment point on Side B and C is $25 million. Maximum capacity for B&C coverage is $25 million. No B&C coverage is available for financial institutions.
XL Professional USA	John T. Burrows, Senior Vice President XL Professional 100 Constitution Plaza Hartford, CT 06103 860-948-1809 860-948-1899 (fax) e-mail: john.burrows@xlgroup.com web: www.xlprofessional.com Bernie Horovitz, Executive Vice President Chief Underwriting Officer 100 Constitution Plaza Hartford, CT 06103 860-948-1819 860-948-1899 (fax)	2012	$50	Full coverage ABC and up to $50 million Side A DIC. All classes of business on primary and excess basis.

Company	Contact	Capacity	(in millions)	Comments
Zurich				
Financial Institutions	Frank Baron, Senior Vice President Management Solutions Group Zurich Financial Institutions One Liberty Plaza, 33rd Floor 165 Broadway New York, NY 10006 212-553-5423 e-mail: frank.baron@zurichna.com web: www.zurichna.com/fe	2012	$25 (average limit is $10)	Writes D&O/E&O for insurance companies with A.M. Best ratings of A- or better, Investment Advisors (including hedge funds) with AUM's starting around $350 million, REITs and banks with assets greater than $10 billion. Does not write BPL for banks of this size. The regional team specializes in stand-alone crime for all financial institutions in addition to banks with assets less than $10 billion for which they do write professional liability.
Zurich Global Corporate U.K.	George Melides Head of Commercial D&O for GCUK and UKGI Zurich Global Corporate U.K. London Underwriting Centre Three Minister Court, Mincing Lane Suite No. 3, 3rd Floor London EC3R 7DD 44-20-7648-3008 e-mail: George.Melides@zurich.com web: www.zurichlondon.com	2012	$50	All classes. Does not write U.S.-domiciled organizations. Issuing paper is Zurich Insurance, Plc.
Zurich Specialties	William Fahey, Senior Vice President Management Solutions Group Zurich Specialties One Liberty Plaza, 30th Floor New York, NY 10006 212-553-5629 e-mail: will.fahey@zurichna.com web: www.zurichna.com	2012	$25	William Fahey oversees all public companies in North America, including Canada. In addition, Mr. Fahey also manages the Fiduciary, Fidelity and Employment Practices books of business for all public companies in North America. Lastly, Mr. Fahey manages the Transactional book, which is comprised of Representations & Warranties, Tax Liability and Contingent Liability Insurance.

Appendix B

Insurance Placement, Reinsurance Intermediary Services and Insurance Program Reviews

Towers Watson places D&O and related executive liability coverages with insurers on behalf of our corporate clients. Towers Watson also provides D&O liability and insurance program reviews for organizations seeking an independent review of risks and coverage.

Executive Liability Insurance Brokerage
Towers Watson provides retail brokerage services as part of our risk management and insurance consulting to clients. We provide a sophisticated alternative to traditional insurance intermediaries that combines seasoned insurance brokerage expertise with the strong analytical and consulting expertise of Towers Watson. Clients can get the benefits of the D&O liability and insurance program review described above, with the additional benefit of having Towers Watson also place the insurance program in the insurance market.

Executive Liability Reinsurance
Towers Watson assists insurance company clients with all aspects of D&O and related lines. Our combined brokerage and insurance consulting expertise provides D&O writers with a broad menu of services, including:

- Primary and excess rate making
- Increased limit factor benchmarking
- Insurance policy comparisons
- Reinsurance contract wording analysis and review
- Stochastic modeling of alternative reinsurance programs to compare the expected costs and impact on the volatility of retained risk
- Monitoring major claims affecting this line of business on a global basis

Towers Watson's staff is dedicated and experienced in negotiating and servicing the specialty product lines associated with D&O liability for U.S. and international exposures.

D&O Liability and Insurance Program Review
A D&O insurance program review provides an independent assessment of the reasonableness and quality of the D&O program as it relates to the organization and its risk profile.

Towers Watson works with clients to do the following:

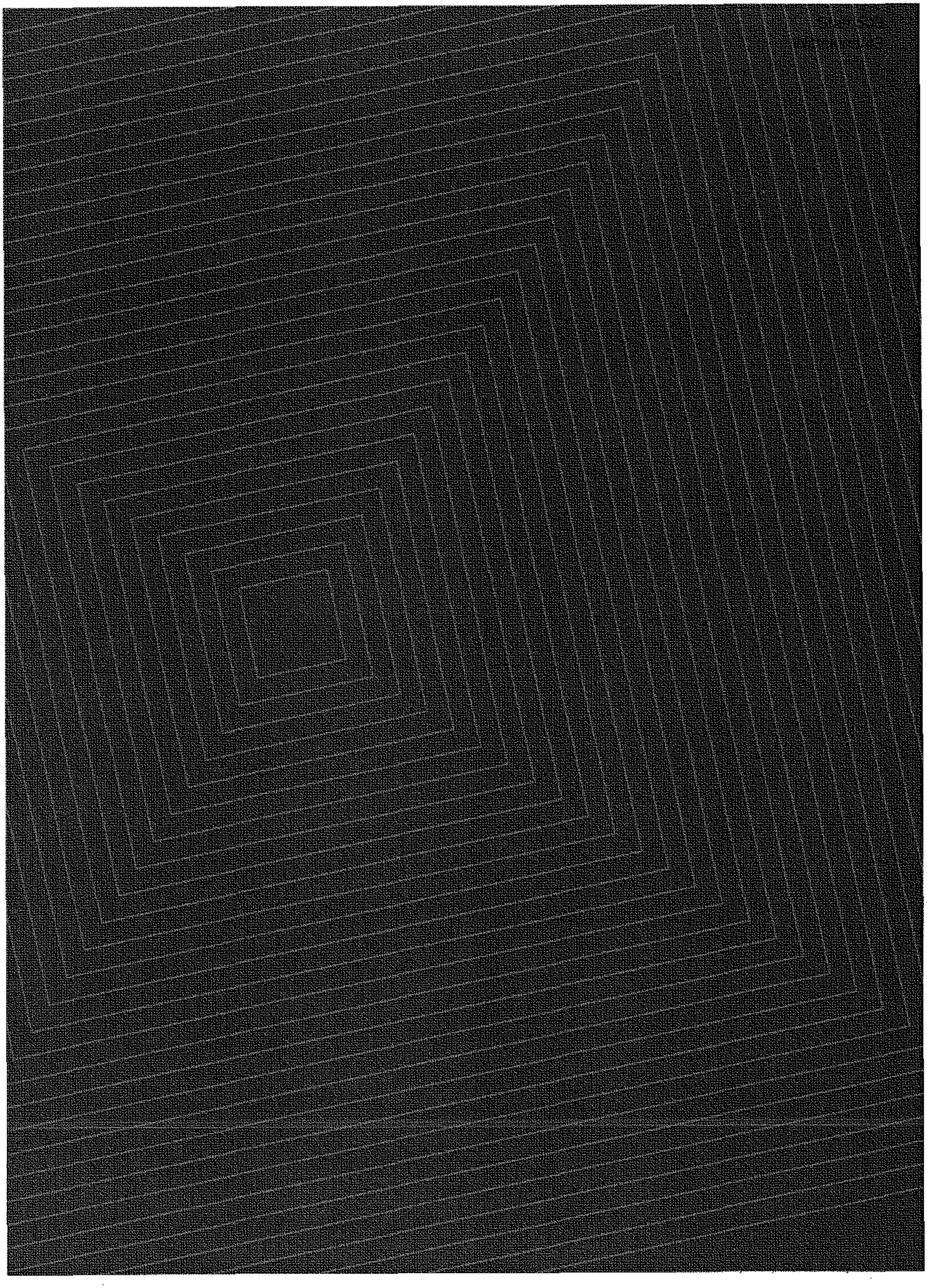
- Explore the company's objectives with respect to its D&O insurance program. For example, is the company trying to minimize costs? Does it need to cover its own liability or payments made to directors and officers? Should it increase the scope of its coverage to ensure that directors and officers are comfortable with their level of protection?
- Check corporate indemnification provisions to see if there are opportunities to improve the breadth of coverage to directors and officers.
- Ensure a thorough understanding of current issues in the litigation environment and the current insurance marketplace, including current trends in D&O claims and insurance purchasing practices.
- Identify the best structure for the program based on the company's unique risk profile, goals for the coverage and appetite for risk.
- Review existing programs for consistency with the company's purchasing philosophy, program cost and current market conditions regarding capacity, pricing and coverage restrictions.

Contacts

Lawrence A. Racioppo
larry.racioppo@towerswatson.com
+1 203 363 1907

Michael Turk
michael.f.turk@towerswatson.com
+1 203 351 5193

Nancy Serio
nancy.serio@towerswatson.com
+1 860 843 7149



About Towers Watson

Towers Watson is a leading global professional services company that helps organizations improve performance through effective people, risk and financial management. With 14,000 associates around the world, we offer solutions in the areas of employee benefits, talent management, rewards, and risk and capital management.

TW-NA-2012-27922

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TOWERS WATSON

CASE: UE 283
WITNESS: LINNEA WITTEKIND

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 504

Exhibits in Support Of Opening Testimony

June 11, 2014

as a shareholder cost. D&O insurance protects PGE senior management in the event that they are sued, whether by customers, stockholders, or others in conjunction with the performance of their Company duties. According to Staff, "[c]ustomers, who have no say in electing or appointing PGE's Directors or Officers, should not be held financially responsible in providing 100 percent of insurance coverage against business decisions or improprieties by management which results in lawsuits."[74] Third, Staff proposes to apply a utility allocation percentage to the overall insurance premiums to allocate the cost between the utility and non-utility aspects of PGE's operations.[75] Finally, Staff proposes a $1.75 million adjustment to PGE's Uninsured Losses based on escalating the five-year historical average by inflation.[76]

PGE contends that D&O liability insurance is a normal cost of doing business, and the entire cost should be included in its revenue requirement. PGE also includes updates to its policies in rebuttal testimony and claims Staff did not properly consider certain policies. PGE further noted that flat insurance rates can still result in increased premiums when property values increase. The Company proposed that the utility allocation factor adjustment should be applied only to a limited number of specific categories.[77]

Resolution

We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost. We also adopt Staff's proposal to hold premiums steady for 2009 property and liability insurance and apply the utility allocation percentage to overall policy premiums. In addition, we adopt Staff's adjustment to Uninsured Losses. PGE's 2009 revenue requirement is therefore reduced by $3.717 million.

h. Miscellaneous Expenses

These expenses consist primarily of costs for catering, gifts, promotional items, and civic activities, including lunch meetings and gifts to employees for overtime work or as retirement gifts, sympathy gifts to employees' families, holiday activities and "team-building days for employees."

Staff proposes that 50 percent of the meal and entertainment expenses, office refreshments and catering, gifts of flowers, and awards be disallowed. In Staff's view, these expenses should be shared equally between ratepayers and shareholders. This approach somewhat mirrors the policy associated with bonuses and the handling of meal and entertainment expenses for income tax purposes.[78]

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[74] *See* Staff/900, Ball/11.
[75] *Id.* at 15.
[76] Staff/300, Ball-Dougherty/11; Staff/900, Ball/14; Staff/901, Ball/4.
[77] PGE Opening Brief at 33-36 and testimony cited therein.
[78] Staff Opening Brief, citing Staff/300, Ball-Dougherty/13-15.

CASE: UE 283
WITNESS: Deborah Garcia

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

June 11, 2014

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

A. My name is Deborah Garcia. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/601.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/602, consisting of 2 pages.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss an adjustment to Portland General Electric's (PGE or Company) proposed Electric Plant in Service (EPIS), a component of the rate base that is included in the Company's test year revenue requirement (Test Year).

Q. What period does PGE propose for the test year?

A. PGE has proposed a normalized future test period of calendar year 2015, except that for rate base they use the forecast balance as of December 31, 2014.[1]

Q. Briefly describe PGE's methodology for calculating the amount of EPIS for the Test Year.

A. First, the Company estimated year-end 2013 embedded plant by starting with the 2013 third quarter actual results plus a forecast of the 2013 fourth quarter. Next, larger expected 2014 capital additions were added based on the forecasted closing date associated with each. Most capital additions were

[1] UE 283/Executive Summary/page 4; PGE/300, Tooman-Macfarlane/27 at 12.

modeled based on the evaluation of Construction Work in Progress (CWIP) balances based on historical experience. The Company then applied a forecast closing pattern to CWIP to develop EPIS estimates from 2014 capital additions.[2]

Q. Does the Company's methodology to estimate EPIS through December 31, 2014, sound reasonable?

A. Yes.

Q. Do you agree with the Company's results?

A. No.

Q. Did the Company provide sufficient information in its filing to support the Test Year EPIS?

A. No. The Company provided an exhibit that showed the addition of approximately $102.8 million EPIS categorized as "Miscellaneous Other" added to the negotiated $7.2 billion EPIS from the Company's last general rate case, UE 263, to arrive at the Test YEAR EPIS of approximately $7.3 billion.[3] The company also filed an exhibit that unbundles the Test Year EPIS into Production, Transmission, Distribution, Metering Billing, and Consumer.[4]

Q. Did PGE provide work papers in support of the Company's stated methodology for the calculation of Test Year EPIS?

A. No.

[2] PGE/300, Tooman-Macfarlane/27 at 12-19.
[3] PGE/Exhibit 308, Tooman-Macfarlane/1.
[4] PGE/Exhibit 309, Tooman-Macfarlane/1.

Q. Please describe the initial step you took to verify the Company's process to calculate the appropriate Test Year EPIS.

A. I issued Data Request Nos. 220 and 221, which are comprehensive, multi-part requests that asked the Company to begin with the actual end-of-period EPIS as reported in its 2012 Results of Operations on file with the Commission, and provide sufficiently detailed information of its actual 2013 and proposed 2014 EPIS additions to arrive at the Test Year EPIS.

Q. Did PGE's responses to the above Data Requests provide you with sufficient information to verify that the Company's proposed Test Year EPIS is appropriate?

A. No. Although the Company responses to the data requests contained 553 pages, 2 spreadsheets, and an additional 78 zipped files each containing multiple pages, a time-consuming review of the data found that the Data Requests were not fully answered. PGE provided a lot of information, but not all of the requested information, with no explanation for missing information, and the provided information was not very well organized to facilitate an efficient review.

Q. What other steps have you taken to verify the Company's proposed Test Period EPIS?

A. I have had multiple telephone conversations with PGE staff and I also issued Data Request Nos. 487-488 to obtain more information. On June 1, 2014, PGE staff came to the PUC offices to walk through the responses to these data requests and answer any other questions Staff might have.

Q. What was the outcome of the June 1, 2014, meeting?

A. PGE staff provided certain specific answers to Staff's questions, acknowledged that certain items should be adjusted from rate base, and agreed to file Supplemental Data Responses to DR No. 220. Staff's questions led to the discovery of issues regarding PGE's capitalization policy that Staff believes should be further investigated. Consequently, Staff has issued additional data requests.

Q. As of now, what general conclusions can you draw regarding the Company's proposed Test Year EPIS?

A. PGE's Test Year EPIS should be adjusted to account for plant that will not meet the used and useful standard in ORS 757.355 of January 1, 2015. The amount should also be adjusted for apparent accounting errors.

Q. Do you have a specific Test Year EPIS adjustment to propose at this time?

A. No. As discussed above, PGE is still in the process of providing certain documentation in support of its proposed 2013 and 2014 EPIS additions. Until Staff receives that information and has a change to thoroughly review it, Staff does not have a specific adjustment for direct testimony, but will propose an adjustment in reply testimony as necessary.

Q. Will you propose any adjustments other than an adjustment of EPIS?

A. Yes. The appropriate adjustments to property tax and depreciation that capture the effect on those items resulting from any adjustment to EPIS will also be proposed.

Q. Does this conclude your direct testimony?

A. Yes.

CASE: UE 283
WITNESS: MARIANNE GARDNER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME: Marianne Gardner

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Revenue Requirement Analyst

ADDRESS: 3930 Fairview Industrial Dr SE, Oregon 97308-1088

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

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

CPA, Oregon

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since March 2013 in the Energy - Rates, Finance and Audit Division of the Utility Program. My responsibilities include research, analysis and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. In my role as summary witness, I have provided testimony in dockets UE 263 and UG 246.

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

- Thirteen years as a cost accountant with responsibilities including cost accounting, budgeting, product costing and the preparation of management reports.

- Four years experience in public accounting working in the areas of audit, tax and financial accounting for individual and small business clientele.

- Three years experience in non-profit accounting for an agency administrating funds under the Federal Job Training Partnership Act.

CASE: UE 283
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 700

Opening Testimony

June 11, 2014

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

A. My name is George R. Compton. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. I have the responsibility for presenting the OPUC Staff's case regarding cost-of-service, rate spread (i.e., the allocation of the revenue requirement increase among the various customer schedules), and rate design/pricing.

Q. In general, how would you characterize PGE's (or Company's) filing with respect to those areas of responsibility?

A. For the past number of years PGE's general rate cases have been resolved via settlements. In the process, PGE has made positive adjustments in their rate case applications corresponding to recommendations made by Staff and by other participating parties. It is the compromising nature of settlements that leads to the fact that probably no party, including Staff, achieves all of its objectives—at least not all at once. In that evolutionary spirit, Staff finds the methodologies employed by the Company in my subject areas in this case to be generally acceptable. That some departures from inherited practices are now being recommended in the testimony which follows should be viewed in the light of continuing with our evolutionary progress rather than as constituting an indictment of PGE's application as being somehow deficient.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared Exhibits Staff/702, Staff/703, and Staff/704. The first shows the effects of Staff's incorporation of wind in the cost-of-service allocations; the second displays Staff's rate spread recommendations; the third is an example of how we would reform the rate design for large industrial customers.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: Incorporating Wind Energy Into The Cost-Of-Service Allocations

Q. In reviewing the cost-of-service (COS) study in the most recent general rate case filing of PacifiCorp, I note the inclusion of wind costs as part of that company's energy cost estimates. In contrast, PGE's COS study does not incorporate wind. While that exclusion was stipulated to in the prior PGE general rate case, is it Staff's intention to include a treatment of wind costs in the current case?

A. Yes. Exhibit 800 of Staff witness, Suparna Bhattacharya, consists primarily of a presentation of combining wind costs with the energy-related costs associated with combined-cycle combustion turbines (CCCTs) to obtain annual composite thermal-wind figures which reflect the upcoming renewable portfolio standard (RPS) ratios. I would note that incorporated in the wind costs are incremental costs of a particular thermal plant's being dedicated in part to supporting the wind supply. By Staff's estimation, incorporating wind increases marginal energy costs by about 3.5%.

Q. What are the general customer schedule cost allocations affects of incorporating wind in the marginal cost calculus?

A. It adds to the costs of the higher load-factor customers, i.e., the large industrial customer schedules whose energy burden is relatively greater than their fixed costs, or demand, burden. Comparing page 1 with page 2 of my Exhibit Staff/702 shows the direct consequences of the wind addition.

ISSUE 2: Alternative Rate Spread Recommendations

Q. I notice that your comparison is with the final recommended increases by PGE, inclusive of Port Westward 2, Tucannon, and a host of supplemental schedules as well as the recommended customer-impact-offset (CIO[1]) values. I assume you made that comparison so as to reveal the direct impacts of introducing wind energy in an "apples-to-apples" setting. Is it Staff's desire to flow those same impacts through to the final recommended outcomes?

A. Not quite. I propose making adjustments through the CIO mechanism that in some cases will offset, at least in part, the increases induced by incorporating wind in the marginal cost analysis. I will also be proposing some other CIO modifications.

Q. Earlier you included achieving greater rates simplicity as one of the purposes of the CIO. Do we see an example of that objective being fostered in the current PGE filing?

A. Yes. In order to bring uniformity to the basic rates of all three outdoor lighting schedules (15 and 91/95), PGE has suggested a positive CIO rate for Schedules 91/95 and a pretty substantial (about one cent per kWh) **negative** rate for Schedule 15.

Q. Does Staff endorse this departure from expressly cost-of-service directed rate designs?

A. We acknowledge the merits of having the same basic charges for all three outdoor lighting schedules. In that sense we do not oppose such an action. But we would not have proposed such on our own initiative.[2] But having accepted this action in a qualitative sense, a subsequent Staff exhibit will display our recommendation that the negative Schedule 15 CIO rate be smaller in absolute value, offset by a larger positive CIO rate for Schedules 91/95.

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[1] The CIO represents departures from strict cost-of-service allocations that are designed to achieve greater rates simplicity/understandability/acceptability, and to mitigate the effects of cost-justified increases that are much greater than the system overall average increase.

[2] To give some perspective regarding the relative magnitude of the lighting schedules, combined they constitute only slightly more that 1% of the Company's revenue requirement.

Q. Historically the most prominent purpose of the CIO has been to ameliorate rate increases that far exceed the system average even though such would have been justified on a cost-of-service basis. Is there an example of this objective being pursued by the Company in this case?

A. There is. Not surprisingly, it has to do with rates charged for agricultural irrigation. Staff's recommendation is for a slight alteration to what PGE is proposing. Going beyond the Company, we would use the CIO to bring down Irrigation Schedule 49's increase from 16.0% to 14.8%, which is the same increase recommended by the Company for Irrigation Schedule 47. The 14.8% figure is approximately three times the 4.9% requested overall average increase for cost-of-service customers.[3]

Q. Based upon our past experiences with general rate cases, we can assume that the final overall average increase for COS customers will be something beneath 4.9%. In that likely event, and with regard to Irrigation Schedules 47 and 49, would Staff stay with the 14.8% increase (assuming such is COS-justified) or prefer the three-times multiple?

A. Actually neither. Our recommendation is for the increase to be the *greater* of 7% or three times the overall COS average.

Q. Why is Staff insisting on the irrigation schedules' increases being at least 7%?

A. In reviewing Exhibit 1404/Cody/Page 8 you will note that the Company's indicated CIO revenues constitute over 40% of the COS allocations to the two irrigation schedules. It is important to bring that contribution down over time regardless of how small might be the system's overall revenue requirement increases.

Q. In reviewing PGE customer-impact-offset Exhibit 1404/Cody/Page 11, I note that apart from the two exceptions which you just discussed, all the

[3] Direct Access will enjoy a decrease, yielding an overall average increase of 4.6%.

schedules incurred a CIO offset figure of plus 0.48 mills/kWh. Does Staff concur with that approach?

A. No. Rather than assigning the same CIO rate to almost all of the schedules, our preference is to have a smaller CIO obligation in the case of schedules who are receiving an increase in excess of the overall average and to have a somewhat larger CIO obligation for the schedules benefitting from a below-average increase. The latter schedules are the outdoor lighting and traffic signals schedules; the former are several of the industrial schedules. The effect is to bring all schedules' increases closer to the system average.

Q. Have you prepared an exhibit which contains Staff's recommended target overall increases under the assumption that PGE were to receive its entire requested revenue requirement increase?

A. I have. It is Exhibit Staff/703, which also shows Staff's recommended CIO rates.

Q. Again reviewing PGE customer-impact-offset Exhibit 1404/Cody/Page 11, I note that the Company's net CIO revenues are only $50 thousand[4] whereas yours are almost a negative $200 thousand. Please explain the discrepancy.

A. In the process of incorporating the wind cost contribution I necessarily relied upon the very elaborate PGE cost-of-service model. Even though I employed the same overall generation revenue requirement, somehow my modeled increase came out to be about $112 thousand in excess of the amount proposed by PGE. Netting that figure against my negative $200 thousand in CIO revenues yields a positive $88 thousand composite. Modelling discrepancies will be rectified when the final revenue requirement is processed through the PGE model.

[4] The ($000) which appears above the other revenues and costs columns of Exhibit 1404/Cody/Page 11 is missing above the CIO revenues column in that exhibit. (Obviously the net CIO revenue contribution from Schedule 7, for example, is more than 3.582 *thousand* dollars.)

Q. Have you prepared a table that is a rough equivalent of Table 1, found on PGE/1400/Cody/2?

A. I have...Table S1 below. It represents the percentage increases inclusive of the January 1, 2015 decreases and the PW2 and Tucannon increases. It is slightly more comprehensive in terms of the schedules that are displayed.

Table S1
Estimated Rate Impacts (%)

Schedule	PGE	Staff
Schedule 7 Residential	5.04	4.95
Schedules 15, 91/95 Lighting; 92 Traffic Signals	1.91	3.19
Schedule 32 Small Nonresidential	4.42	4.44
Schedules 47, 49 Agricultural	15.66	14.78
Schedule 83 31-200 kW	4.61	4.63
Schedule 85 201-4,000 kW	4.92	4.97
Schedule 89 Over 4000 kW	5.94	5.80
Schedule 90 100 MWa	4.66	4.95
Cost-of-Service Overall	4.95	4.95
Cost-of-Service & Direct Access Overall	4.63	4.63

ISSUE 3: Advancing Large Industrial Rate Design

Q. In comparing PGE's industrial schedules with those of PacifiCorp's, I note the absence of a demand charge component in the former's "Energy Charge." The latter's Schedule 200 contains such a charge.[5] Can you explain the disparity?

A. PacifiCorp's generation demand charge represents an outcome of a negotiated settlement. PGE has successfully resisted using a demand charge to recover a portion of that utility's generation costs.[6]

[5] PGE's "Energy Charge" components in each customer schedule recover that schedule's share of both the energy and the demand portions of its generation/production costs. Expressed another way, the "Energy Charge" recovers both the variable and the fixed portions of that Company's generation/production costs. Corresponding PacifiCorp variable and fixed tariffs are, respectively, Schedules 201 and 200. The "Distribution Charges" for both firms' large customers include demand charges.

[6] *See* pages 31 through 33 of Exhibit UE 262/PGE/1500 Cody-Macfarlane for a presentation of arguments against using the demand charge for recovering generation costs.

Q. Does Staff oppose the inclusion of a demand charge with PGE's "Energy Charge(s)"?

A. No—but this is the distinction: Traditional demand charges are non-coincident-peak (NCP) based; Staff supports a generation demand charge *provided* it can be *coincident*-peak (CP) based.

Q. Please elaborate.

A. Conventional demand billings are based upon individual customers' monthly own/*non*-coincident peak (NCP) demands. Accordingly they represent a blunt instrument for collecting true system demand costs, which are a function of system *coincident* peak (CP) demands—and more particularly a function of system peak demands during system peak *months*, which for PGE are January, July, August, and December. To be consistent therefore with cost-causation, what are here being proposed are demand charges that would be imposed on customers' peak loads on the day of the monthly *coincident* peak, and would only apply to the just-listed four months. The advantage of a high peak-period *energy* charge over a NCP-based *demand* charge is that once what is perceived as being the likely highest demand for the month has been triggered, the customer no longer has an incentive to conserve on its load; but with the higher time-of-day peak-period price (i.e., made possible by the absence of a demand charge), the incentive is always there to conserve during the designated hourly peak time periods.

Q. Given the cost-causation advantages of coincident-peak based demand charges for generation cost recovery, why have utilities historically employed non-coincident based demand charges?

A. Traditional NCP-based meters, which measure the maximum demand achieved during the month, have been around for scores of years. Meters which record demands on an hour-by-hour basis—i.e., as needed to measure CP-based demands—represent a more recent technology. PGE has deployed this technology for all its Oregon customers; PacifiCorp has limited its installation to large customers. I have also been told that changing from an NCP to a CP-based demand complicates—i.e., adds costs to—the billing process.

Q. Isn't it true that the time of the coincident peak for a given month will not be known assuredly until the month has ended? In that case how will a customer be responsive to the objective to conserve during the peak? Would this be a case of retroactive pricing since the level of demand to which the price will be applied would not be known until the end of the month?

A. Let me answer first by saying that under the conventional NCP demand charge, the peak demand may, theoretically, not be registered until the end of the month—also leaving the customer not knowing until then just what level of demand the demand charge will be applied to. More seriously, what I have in mind is for the utility to be allowed a limited number of peak-liable days, say four, during each of the four peak months[7] for which 24-hour notice would be provided that such might be the day experiencing the system coincident peak. The conservation-minded customer would then only have to be concerned about his demand level during those limited number of days. The demand charge would be levied against the customer's peak demand that occurred during whichever of those four days indeed experienced its maximum system peak load.[8]

Q. Since the system peak load occurs in a particular hour, would your demand charge be applied only against the demand that occurred precisely in that hour?

A. No. It would be asking too much of customers to not know with any precision until the end of the month what level of demand it would be charged for since the customer would not know the hour of the system peak. It makes more sense to say the charge would be leveled against whatever was the customer's

[7] They are December, January, July, and August. Inter-schedule generation capacity cost allocations are based upon those four months' coincident peak load contributions.

[8] If for some reason the utility had not called a peak-liable day prior to the next-to-last day of the month, it would surely call for one for the last day of the month in order to collect demand revenues for the month.

peak demand during the target day's entire conventional sixteen-hour "heavy load period."[9]

Q. Have utilities employed rate design measures other than CP-based demand charges for encouraging customers to reduce their on-peak loads?

A. They have. It has been to introduce a much narrower peak period than the sixteen hour "on-peak" period utilized by both PGE and PacifiCorp. (A third, mid-peak period is typically defined as what is left over from the currently defined sixteen-hour, heavy-load-hour "peak" period after withdrawing the new on-peak hours.) Having the smaller on-peak period enables the on-peak price to be higher and the off-peak price to be lower than otherwise.

Q. Is Staff recommending the introduction of a three-period energy rate design and eliminating the two-period approach currently used by PGE for its industrial schedules?

A. Yes. The recommended three different periods are as already adopted in Sheet 7-3 of PGE's current residential optional time-of-use tariff. Notably, the winter on-peak period(s) is defined as 6 a.m. to 10 a.m. and 5 p.m. to 8 p.m.; and the summer on-peak period is defined as 3 p.m. to 8 p.m. The peak periods are limited to week days.

Q. I see that you have defined peak periods for explicit energy charges that are narrower than the Company's sixteen hour "On-Peak" period. Why don't you limit the application of your CP-based demand charge to those fewer hours?

A. I am concerned about the creation of a harmful "needle peak" that would follow immediately after the narrower on-peak period as large customers turned heavy equipment back on. Such would not be a threat if customers held off until after the end of the Company's designated On-Peak period, i.e., at 10 p.m.

[9] PGE's "On-Peak [distribution, not generation] Demand" charge is only levied against a demand that occurred during its designated sixteen hour heavy load period of 6 a.m. to 10 p.m.

Q. You referred earlier to the merits of elevated on-peak energy charges *in lieu* of generation demand charges. I notice that you have indeed narrowed the on-peak period to something that more closely captures what actually might be PGE's system peak, and that you have elevated that on-peak price to something greater than PGE's. Why doesn't that suffice for achieving Staff's objective of better tracking cost causation?

A. That would be an improvement over the status quo, but the narrower "on-peak" period would still apply to every week day of the month. Targeting the demand charge to at most four days in the month would have the advantage of focusing conservation efforts to where such would most likely benefit the system in terms of being able to get by with lower capacity costs. This can be looked upon as something very similar to "critical peak pricing," where a much larger energy (as opposed to demand) rate is applied for just a few hours out of just a few days of the key demand months.

Q. Have you constructed a set of prices that would include a CP-based demand charge plus the three-period time-of-use energy rates such as you have been describing?

A. I have. An example applied to Schedule 83 is displayed in Exhibit Staff/704. Similar examples for Schedules 85, 89, and 90 are included with my work-papers.

Q. Earlier you alluded to billing cost increases as being an impediment to the introduction of CP-based demand charges by retail utilities. Might that be the current case with PGE?

A. Yes. While Bonneville incorporates CP-based billing in its business model, PGE does not now possess that capability. Cost efficiency within PGE would be fostered by including that capability within the totally revamped billing system now being undertaken over a two-year period rather than taking on the expense of creating a separate CP capability within the current, soon-to-be-obsolete billing system.

Q. Given that administrative untimeliness, is there anything that can be done within the current docket to send a more cost-based pricing signal to the larger customers?

A. There is. One approach would be to take an intermediated step and implement three-period energy rates. If even that is not feasible without major billing software intervention, merely increasing the on-peak/off-peak price differential from one cent per kWh to two cents would be a good step in the right direction. The one cent figure is a purely energy-cost based figure and does not capture the capacity/demand costs that attend the production of electricity during the heavy load hours.

Q. What might be done outside the current docket to move us closer to your cost-based pricing?

A. PGE should be instructed to sponsor a workshop whose purpose is to discuss implementation issues from both the Company's and the industrial customers' points of view.

Issue 4: A Short Treatise on Basic Charges

Q. PGE is proposing to increase the Schedule 7 monthly basic charge from $9 to $11. Does Staff approve?

A. No, for two reasons: 1. Increasing the basic charge by 22% in the context of a general rate case involving less than a 5% overall increase certainly stretches things from a customer acceptance/credibility point of view. 2. The $11 figure is well above the summed marginal cost of universally accepted customer-cost/basic-charge components. In fact, that sum is less than $10.

Q. What are the universally recognized customer-cost/basic-charge components to which you have just referred?

A. They include costs inevitably incurred by each customer *individually* in being served. Examples are the meter, meter-reading and billing, the service drop between the local distribution transformer and the meter, and the distribution transformer itself, or at least a minimal share thereof in the event that the transformer can simultaneously serve more than one customer.

Q. What is the sum of the marginal cost of those items for single-phase residential customers?

A. From PGE/Exhibit 1405/Cody Page 12, I see annual costs of $20.41 for meters and $70.70 for service and transformer; and from Page 18 of that same exhibit I see $24.45 for billing. Summing those amounts and dividing by 12, I obtain $9.63 per month.

Q. Referring to PGE/Exhibit 1404/Cody Page 3, I see that while the requested basic charge is, again, $11, the costs upon which that charge is based is $21.38 per customer per month. Can you explain the discrepancy between your sub-$10 marginal cost figure and the $21.38 embedded cost figure?

A. No, I can't. Because of the tendency to denote as "customer costs" everything that is not readily categorized as energy- or demand-related, there are undoubtedly other kinds of costs that are included in that larger figure. Also, even where the "service" is defined and recognized as a legitimate customer-cost item as described earlier, there can be a huge difference between per-customer marginal costs and per customer embedded costs. Take "Billing" for example (*see* PGE/Exhibit 1405/Cody Page 18): Embedded costs (i.e., the estimated Class Revenue Requirement) are indicated to be three times marginal costs. Again, I don't know why there should be that much of a difference.

Q. What if anything do you have against setting the Basic Charge at a level significantly above marginal costs—i.e., closer to customer-related embedded costs?

A. Basic economic theory and principles of equity dictate that each customer should at least cover its marginal costs. Beyond that, i.e., for the revenue requirement balance above marginal costs, the question is how best to achieve other regulatory and societal objectives. Recognizing that, historically, marginal *production* costs have *exceeded* embedded production costs, shifting embedded "customer cost" recovery over to production, i.e., per kWh, *prices* has allowed the latter to come closer to marginal costs without compromising authorized returns on rate base. Environmental considerations have also motivated increasing per kWh prices beyond narrow embedded cost levels so as to encourage energy conservation.

Q. What is Staff's recommended residential monthly basic charge?

A. Staff recommends $9.50. That takes into account the fact that PGE is unlikely to be awarded its entire requested increase.

Q. You have provided a recommendation regarding the residential basic charge...how about the basic charges for other schedules?

A. Staff has no particular recommendation here apart from mimicking the same relationship between a marginal-cost based customer charge and embedded customer costs. The Company itself departs from that relationship with its $25 *thousand* per-month Schedule 90 customer charge, which is well above the embedded costs for the conventional customer cost function. Justification given[10] is that distribution feeders, which are ordinarily categorized as distribution costs rather than customer costs, can in this case be identifiable as customer-specific rather than shared, and therefore "reasonably" regarded as a "customer-related cost." With only four Schedule 90 customers, I suppose this matter will ultimately be negotiated, and in a way that is revenue neutral for the Company.

Q. Does this conclude your direct testimony?

A. Yes.

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[10] *See* PGE/1400/Cody/24.

CASE: UE 283
WITNESS: GEORGE COMPTON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME: George R. Compton

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
Rates, Finance & Audit

ADDRESS: 3930 Fairview Industrial Dr SE
Salem, OR 97308-1088

EDUCATION: Doctor of Philosophy, Economics (1976)
University of California, Los Angeles (UCLA) – Westwood, CA

Master of Science, Statistics (1968)
Brigham Young University (BYU) – Provo, UT

Bachelor of Science, Mathematics and Psychology (1963)
Brigham Young University – Provo, UT

EXPERIENCE: I have been employed in utility regulation since receiving my Ph.D. in 1976. My primary employer was the Division of Public Utilities, within Utah's Department of Commerce (formerly Business Regulation). I also consulted for a couple of years, early in that period. I testified frequently during my career on rate design, cost-of-service, cost-of-equity, and various policy matters affecting electric, gas, and telephone utilities. While in Utah, I also taught Economics part-time for about ten years at BYU.

Prior to my utility regulatory career, I worked in aerospace for eleven years at McDonnell Douglas (now Boeing) in Southern California.

I joined the OPUC staff soon after "retiring" to Oregon at the end of 2006. Principal cases of my involvement here have included the IRP/CO_2 Risk Guideline (UM 1302), an Avista General Rate Case (UG 181), PGE General Rate Cases (UE 197, UE 215, and UE 262), PacifiCorp General Rate Cases (UE210, UE 246, and UE 263), the NW Natural General Rate Case (UG 221), and the Idaho Power General Rate Case (UE 233).

PORTLAND GENERAL ELECTRIC ORIGINAL **TABLE 6**
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS WITH PORT WESTWARD 2 AND TUCANNON
2015

CATEGORY	RATE SCHEDULE	Forecast SDEC13E15 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	740,049	7,462,740	$865,667,667	$909,285,890	$43,618,223	5.04%
Employee Discount				($901,500)	($947,746)	($46,245)	
Subtotal				$864,766,167	$908,338,144	$43,571,977	5.04%
Outdoor Area Lighting	15	0	15,972	$3,720,554	$3,746,640	$26,086	0.70%
General Service <30 kW	32	89,471	1,556,500	$172,367,833	$179,984,699	$7,616,866	4.42%
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,796,145	$6,183,442	$387,297	6.68%
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,936,637	$3,371,386	$434,749	14.80%
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,634,170	$8,855,043	$1,220,872	15.99%
General Service 31-200 kW	83	10,953	2,735,660	$248,856,924	$260,330,589	$11,473,665	4.61%
General Service 201-4,000 kW							
Secondary	85-S	1,239	2,431,372	$196,724,916	$205,847,878	$9,122,962	4.64%
Primary	85-P	192	645,752	$48,174,223	$51,101,085	$2,926,861	6.08%
Schedule 89 > 4 MW							
Primary	89-P	18	913,928	$58,653,931	$62,243,675	$3,589,744	6.12%
Subtransmission	89-T	5	209,810	$14,329,190	$15,075,593	$746,404	5.21%
Schedule 90	90-P	4	1,453,535	$88,554,928	$92,682,302	$4,127,374	4.66%
Street & Highway Lighting	91/95	205	97,094	$18,143,668	$18,529,270	$385,602	2.13%
Traffic Signals	92	17	3,327	$265,561	$276,041	$10,480	3.95%
COS TOTALS		847,034	17,656,462	$1,730,924,847	$1,816,565,787	$85,640,940	4.95%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	436,001	$11,089,832	$9,660,047	($1,429,785)	
Primary	485-P	41	220,953	$5,535,287	$4,874,490	($660,797)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,864	$549,126	$521,325	($27,802)	
Primary	489-P	9	506,343	$7,589,496	$6,456,978	($1,132,518)	
Subtransmission	489-T	3	333,091	$3,993,810	$3,095,411	($898,399)	
DIRECT ACCESS TOTALS		214	1,511,253	$28,757,552	$24,608,250	($4,149,301)	
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,759,682,399	$1,841,174,037	$81,491,639	4.6%

PORTLAND GENERAL ELECTRIC ORIGINAL TABLE 6 MODIFIED TO ACCOUNT FOR WIND
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS WITH PORT WESTWARD 2 AND TUCANNON

CATEGORY	RATE SCHEDULE	CUSTOMERS (Forecast SDEC13E15)	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED with all supplementals except LIA & PPC	Change AMOUNT	Change PCT.
Residential	7	740,049	7,462,740	$865,667,667	$908,764,931	$43,097,264	4.98%
Employee Discount				($901,500)	($947,178)	($45,678)	
Subtotal				$864,766,167	$907,817,753	$43,051,586	4.98%
Outdoor Area Lighting	15	0	15,972	$3,720,554	$3,747,917	$27,364	0.74%
General Service <30 kW	32	89,471	1,556,500	$172,367,833	$180,013,908	$7,646,075	4.44%
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,796,145	$6,186,494	$390,349	6.73%
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,936,637	$3,370,660	$434,023	14.78%
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,634,170	$8,853,662	$1,219,492	15.97%
General Service 31-200 kW	83	10,953	2,735,660	$248,856,924	$260,385,302	$11,528,378	4.63%
General Service 201-4,000 kW							
Secondary	85-S	1,239	2,431,372	$196,724,916	$205,993,760	$9,268,844	4.71%
Primary	85-P	192	645,752	$48,174,223	$51,146,287	$2,972,064	6.17%
Schedule 89 > 4 MW							
Primary	89-P	18	913,928	$58,653,931	$62,352,487	$3,698,556	6.31%
Subtransmission	89-T	5	209,810	$14,329,190	$15,110,328	$781,138	5.45%
Schedule 90	90-P	4	1,453,535	$88,554,928	$92,885,797	$4,330,869	4.89%
Street & Highway Lighting	91/95	205	97,094	$18,143,668	$18,537,037	$393,369	2.17%
Traffic Signals	92	17	3,327	$265,561	$276,507	$10,946	4.12%
COS TOTALS		847,034	17,656,462	$1,730,924,847	$1,816,677,900	$85,753,053	4.95%
Direct Access Service 201-4,000 kW							
Secondary	485-S	160	436,001	$11,089,832	$9,660,047	($1,429,785)	
Primary	485-P	41	220,953	$5,535,287	$4,874,490	($660,797)	
Direct Access Service > 4 MW							
Secondary	489-S	1	14,864	$549,126	$521,856	($27,271)	
Primary	489-P	9	506,343	$7,589,496	$6,461,788	($1,127,708)	
Subtransmission	489-T	3	333,091	$3,993,810	$3,099,964	($893,846)	
DIRECT ACCESS TOTALS		214	1,511,253	$28,757,552	$24,618,145	($4,139,406)	
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,759,682,399	$1,841,296,045	$81,613,647	4.6%

PORTLAND GENERAL ELECTRIC ORIGINAL **TABLE 6** MODIFIED TO ACCOUNT FOR **WIND** AND REFLECTING STAFF'S **CIO** RECOMMENDATIONS
ESTIMATED EFFECT ON CONSUMERS' TOTAL ELECTRIC BILLS WITH PORT WESTWARD 2 AND TUCANNON
2015

CATEGORY	RATE SCHEDULE	Forecast SDEC13E15 CUSTOMERS	MWH SALES	TOTAL ELECTRIC BILLS CURRENT with all supplementals except LIA & PPC	TOTAL ELECTRIC BILLS PROPOSED Wind-adjusted, with all supplementals except LIA & PPC	Staff Wind-Adjusted Change AMOUNT	Staff Wind-Adjusted Change PCT.	Staff Recommended Target Increase PCT.	Staff Recommended Delta Change AMOUNT	PGE-Proposed CIO mills/kWh	Staff-Proposed CIO mills/kWh	Staff-Proposed CIO Revenues
Residential	7	740,049	7,462,740	$865,667,667	$908,764,931	$43,097,264	$0	$0	-$246,714	0.48	0.45	$3,358,233
Employee Discount				-$901,500	-$947,178	-$45,678						
Subtotal				$864,766,167	$907,817,753	$43,051,586	$0	$0	-$245,661			
Outdoor Area Lighting	15	0	15,972	$3,720,554	$3,747,917	$27,364	0.74%	1.78%	$38,812	-10.58	-8.15	-$130,172
General Service <30 kW	32	89,471	1,556,500	$172,367,833	$180,013,908	$7,646,075	4.44%	4.44%	$0	0.48	0.48	$747,120
Opt. Time-of-Day G.S. >30 kW	38	561	43,599	$5,796,145	$6,186,494	$390,349	6.73%	6.50%	-$13,600	0.48	0.17	$7,412
Irrig. & Drain. Pump. < 30 kW	47	2,991	18,147	$2,936,637	$3,370,660	$434,023	14.78%	14.78%	$0	-97.66	-97.66	-$1,772,260
Irrig. & Drain. Pump. > 30 kW	49	1,329	69,025	$7,634,170	$8,853,662	$1,219,492	15.97%	14.78%	-$91,193	-105.19	-106.51	-$7,351,892
General Service 31-200 kW	83	10,953	2,735,660	$248,856,924	$260,385,302	$11,528,378	4.63%	4.65%	$43,469	0.48	0.5	$1,367,830
General Service 201-4,000 kW												
Secondary	85-S	1,239	2,431,372	$196,724,916	$205,993,760	$9,268,844	4.71%	4.75%	$75,589	0.48	0.51	$1,240,000
Primary	85-P	192	645,752	$48,174,223	$51,146,287	$2,972,064	6.17%	5.85%	-$153,872	0.48	0.24	$154,981
Schedule 89 > 4 MW												
Primary	89-P	18	913,928	$58,653,931	$62,352,487	$3,698,556	6.31%	6.00%	-$179,320	0.48	0.28	$255,900
Subtransmission	89-T	5	209,810	$14,329,190	$15,110,328	$781,138	5.45%	5.00%	-$64,679	0.48	0.17	$35,668
Schedule 90	90-P	4	1,453,535	$88,554,928	$92,885,797	$4,330,869	4.89%	4.95%	$52,600	0.48	0.52	$755,836
Street & Highway Lighting	91/95	205	97,094	$18,143,668	$18,537,037	$393,369	2.17%	3.47%	$235,938	1.74	4.17	$404,882
Traffic Signals	92	17	3,327	$265,561	$276,507	$10,946	4.12%	4.25%	$341	0.48	0.58	$1,930
COS TOTALS		847,034	17,656,462	$1,730,924,847	$1,816,677,900	$85,753,053	4.95%	4.95%	-$301,575			-$924,531
Direct Access Service 201-4,000 kW												
Secondary	485-S	160	436,001	$11,089,832	$9,660,047	-$1,429,785				0.48	0.48	$209,281
Primary	485-P	41	220,953	$5,535,287	$4,874,490	-$660,797				0.48	0.48	$106,058
Direct Access Service > 4 MW												
Secondary	489-S	1	14,864	$549,126	$521,325	-$27,802				0.48	0.48	$7,135
Primary	489-P	9	506,343	$7,589,496	$6,456,978	-$1,132,518				0.48	0.48	$243,045
Subtransmission	489-T	3	333,091	$3,993,810	$3,095,411	-$898,399				0.48	0.48	$159,884
DIRECT ACCESS TOTALS		214	1,511,253	$28,757,552	$24,608,250	-$4,149,301						$725,402
COS AND DA CYCLE TOTALS		847,248	19,167,715	$1,759,682,399	$1,841,286,150	$81,603,752	4.64%	4.63%				-$199,129

Staff/703
Compton/1

Staff-Recommended Production Cost Pricing for Schedule 83

Source	Product	Season	Period	Volume	Price mills/kWh or $/kW	Revenue ($)	Target Revenue ($)
PGE	Energy	All	Off-Peak	984,073	**51.59**	50,768,340	
PGE	Energy	All	On-Peak	1,751,587	**61.59**	107,880,235	
PGE Totals				2,735,660		158,648,575	158,883,000
Staff	Energy	All	Off-Peak	984,073	**45.00**	44,283,297	
	Energy	All	On-Peak	559,717	**70.00**	39,180,179	
	Energy	Winter	Mid-Peak	542,980	**62.00**	33,664,784	
	Energy	Summer	Mid-Peak	648,890	**58.00**	37,635,600	
Totals				2,735,660		154,763,859	155,112,454
	Demand	Both	Four-Peak	1,885,273	**2.00**	3,770,546	
Staff Totals						158,534,405	158,883,000

NOTE: Staff's various "Periods" are as defined in Sheet 7-3 of PGE's tariff, effective July 1, 2012.

CASE: UE 283
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

REDACTED
June 11, 2014

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 800

PAGES 5, 6 AND 7 ARE CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 14-043.

YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 283 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

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

A. My name is Suparna Bhattacharya. I am a utility Economist in the Energy – Rates, Finance, and Audit section of the Public Utility Commission of Oregon. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97302-1166.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. My testimony reviews and recommends changes in the methodology PGE uses to estimate the long run marginal cost of generation. This testimony also addresses the transmission marginal cost allocation

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Exhibit Staff/800 Opening Testimony
Exhibit Staff/801 Witness Qualification
Exhibit Staff/802 Data Request Responses
Exhibit Staff/803 Wind-Direct Marginal Cost Estimation
Exhibit Staff/804 Marginal Generation Cost with Wind Integration
Exhibit Staff/805 Marginal Energy Costs for each Schedule

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1, Marginal Generation Cost

Q. Please identify the specific components of the Company's marginal generation cost on which you focus.

A. I focus on PGE's marginal cost of generation capacity and marginal cost of generation energy.

Q. Please describe PGE's approach to estimate marginal generation cost.

A. The fixed cost of a simple cycle combustion turbine (SCCT) defines the capacity cost, while the fixed costs of a Combined Cycle Combustion Turbine CCCT that are in excess of SCCT fixed costs comprise a portion of the marginal energy cost. CCCT fuel costs constitute the balance of the generation marginal energy costs.

Q. Do you agree with the Company's approach to estimate marginal generation cost?

A. No. Staff proposes the following for the capacity and energy components of the marginal generation cost:

- Continue using basic SCCT for identifying marginal capacity costs
- Incorporate wind cost to be an additional component in estimating marginal energy costs

Q. Why does Staff recommend inclusion of wind power in the marginal generation cost estimation?

A. To comply with Renewable Portfolio Standard (RPS), set forth in ORS 469A.005 to 469A.300, Oregon utilities are required to include a certain percentage of renewables in their fuel portfolio. RPS requirements for PGE are

15% by 2020, 20% by 2025, and 25% henceforth.[1] The Integrated Resource Plan (IRP), 2013, shows that the Company would rely mostly on wind resource to meet the RPS requirements.[2]

Q. Has PGE included wind in the marginal cost study of previous rate cases?

A. Yes, PGE included wind in the original filing of UE 215 and UE 262.[3] In both these cases, Staff supported the inclusion of wind in the marginal cost study, but objected to PGE's methodology for incorporating wind into the cost study. In this docket, UE 283, PGE proposes using a variable generating resource as the marginal capacity cost should wind be included in the study. This type of generation resource is more expensive on a per kW basis than a basic SSCT.

Q. Why did Staff object to PGE's methodology in UE 262?

A. Staff's position is that if PGE is building variable generating resources as a direct result of building wind resources then any capital cost beyond that of a SSCT must be a direct result of having wind resources. Given that Staff views wind as an energy-only resource, the additional $/kW cost of the variable generating capacity resource beyond that of a SCCT should be assigned as an energy cost relating to supplying wind energy because it does not increase the peak generating capacity of PGE beyond that of a basic SSCT.

Q. Please briefly describe the Company's approach (if any) to incorporate wind cost in estimating marginal cost of generation.

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[1] http://www.oregon.gov/ENERGY/RENEW/Pages/RPS_home.aspx
[2]http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp.pdf
[3] See PGE response to Staff DR 302.

A. In response to a data request by the Citizen's Utility Board (CUB), PGE provided a hypothetical example that describes how the Company would integrate wind into marginal generation cost estimation for RPS compliance from the time period 2015 - 2034.[4] The steps below show PGE's calculation of the marginal capacity and energy costs of generation with wind:

- Marginal capacity cost is calculated as the weighted average of thermal SCCT capacity costs and the marginal capacity costs of the more expensive thermal reciprocating engine used to support wind. So, if thermal capacity cost of SCCT is $100/KW-year and the flexible, wind-accommodating reciprocating engine capacity cost is $180/KW-year for 2015, then the marginal capacity cost for 2015 with a 15% RPS requirement is 0.15*(180) + 0.85*(100).
- Marginal energy cost is calculated as the weighted average of thermal and wind marginal energy costs. So, for instance, if thermal and wind marginal energy costs are, respectively, $50/MWh and $67/MWh, then the marginal energy cost for 2015 with 15% RPS requirement is estimated as 0.15*(67) + 0.85*(50).

After discussing with PGE, I understand that wind marginal energy costs is defined by PGE as the sum of capital carrying costs, fixed O&M costs, land rents, production tax credits, and ancillary services less integration and wheeling costs.

[4] See Exhibit Staff 802; PGE response to CUB DR 29.

Q. Does Staff agree with the company's approach to estimating marginal generation cost with wind? If not, please describe Staff's approach.

A. No. Staff proposes that the portion of the flexible thermal resource costs that exceeds the SCCT $/kW costs, dedicated as a reserve to offset wind variability and to maintain system reliability, should be identified as a part of the marginal energy cost and not as a part of the capacity cost component of the marginal generation cost estimation. Staff has developed a new methodology that improves upon the Company's approach to including wind costs in marginal generation cost analysis. Specifically, Staff performs the following steps to measure the marginal capacity and energy costs of the generation cost with wind integration for the period 2015-2034:

Marginal Capacity Cost

- Marginal capacity cost is determined from the thermal SCCT capacity costs. So, based on PGE work papers 1400 LRMC_conf, if the marginal capacity cost of SCCT in 2015 is [redacted], then the marginal capacity cost for 2015 is [redacted] independent of the 15% RPS requirement.

Marginal Energy Cost

- Marginal energy cost is the weighted average of thermal and total wind marginal energy costs based on the RPS requirements. Thermal marginal energy cost is [redacted] for 2015, based on the work file HourlyMCenergy- GRC15 from PGE work papers 1400. Total wind marginal energy cost is the sum of two cost components — incremental cost of the flexible thermal resource per-wind-unit and direct wind energy cost.

- Staff follows the following steps to measure the two cost components of the total wind marginal energy cost
    - In order to calculate the cost contribution of the flexible thermal resource, Staff assumes the capacity of that resource is 220MW and assumes that the additional capacity unit cost of this flexible thermal generation unit is justified by its ability to meet the random fluctuations attributed to wind power uncertainty (may be within hour variability – regulation and load following).
    - Based on PGE's response to Staff Data Request 299, Staff assumes the cost of this expensive flexible resource is [redacted]. Thus, the incremental unit cost of the flexible thermal resource attributable to wind handling is the difference between the flexible thermal resource cost and the marginal capacity cost of SCCT. For instance, the incremental unit cost for 2015 is ([redacted] - [redacted]).
    - Given the flexible thermal resource capacity of 220 MW, the incremental cost of the flexible wind-handling thermal resource is calculated as incremental unit cost times the flexible thermal resource capacity. In 2015, for example, the incremental cost of the flexible wind handling capability would be

([redacted] - [redacted])*(220*1000).

- Next, to compute the incremental cost of this flexible resource per MWh of annual wind generation, Staff considers the total annual wind generation from the wind farms Bigelow Canyon 1, 2, 3, and Tucannon.[5] Given a projection of 2,076,575 MWh total annual wind generation from these wind farms, the per-wind-unit cost of the flexible wind-handling thermal resource is calculated as the incremental cost of the flexible wind handling capability over the total annual wind generation. Thus, for the year 2015, per-wind-unit cost of flexible thermal resource would be ([redacted] - [redacted])*(220*1000)/2,076,575.
- Staff refers to PGE's response to Staff Data Request 301 and makes some modifications to calculate the direct wind energy cost.[6] In particular, wind energy cost is measured as the sum of capital carrying costs, fixed O&M costs, land rents, production tax credits, ancillary services, integration less the wheeling costs. This calculation is based on the integration cost of $3.63/MWh (in 2013$) based on the PGE response to Staff Data Request 463 and Section 8.6 of PGE 2013 Integrated Resource Plan (IRP) report.[7]

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[5] UE 286 PGE NVPC APCU\Filing (April 1, 2014)\Confidential disk\ToPUC\#M610PUC10-056-2015 GRC.xlsm

[6] Please refer to Exhibit 1 for wind-direct energy cost estimation.

[7] http://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2013_irp.pdf

- Wind energy cost will increase if wheeling cost is counted. Staff is still analyzing this aspect but for now has not included in this estimation.
- The total wind marginal energy cost, as mentioned above, is derived by adding the two cost components:
  incremental cost of flexible wind-handling thermal resource per wind-unit + direct wind marginal energy cost
- Based on the above calculations, the weighted marginal energy cost for 2015 with 15% RPS requirement can be expressed as 0.15*(total wind marginal energy cost) + 0.85*(thermal marginal energy cost)

Q. Why do you spread the incremental cost of the flexible thermal resource across the entire amount of PGE wind generation?

A. PGE does not have a one-to-one relationship between flexible thermal capacity and wind capacity. PGE has many options to meet the variability in wind generation, including market purchases and other less flexible thermal resources. Staff submitted Staff Data Request 296 to help determine the relationship between wind and flexible thermal resources; however PGE was unable to provide this relationship. Staff assumes that the wind handling thermal resource has sufficient flexible thermal capacity to support PGE's entire annual wind generation.

Q. Do you include all incremental wind costs in your analysis?

A. No. This analysis does not include Bonneville's variable energy resource balancing service. Doing so may result in double counting given that Staff has included the cost of the variable capacity resource.

Q. Have you prepared an exhibit that shows wind-direct marginal energy cost estimation?

A. Yes, Exhibit 803 shows the year by year calculations of the wind-direct marginal energy cost.

Q. Have you prepared an exhibit that shows marginal generation costs estimation with wind integration?

A. Yes, Exhibit 804 shows the year by year calculations of the marginal generation costs incorporating wind.

Q. Have you prepared an exhibit that shows how adding wind increases the marginal energy costs of each schedule for the current test period?

A. Yes, Exhibit 805 shows the marginal energy and capacity cost allocations for each schedules for the current test period. Staff refers to HourlyMCenergy-GRC15 and MCenergy-2015 from PGE work papers 1400 to determine the cost allocations with wind integration.

Issue 2, Transmission Marginal Cost

Q. How does PGE allocate transmission costs?

A. PGE allocates transmission costs based on each schedule's share of demand and energy. Demand is weighted by 65 percent and energy is weighted 35 percent. Demand is calculated using a four period coincident peak.

Q. What is the basis of the 65/35 split?

A. PGE's response to Staff Data Request 376 indicates that the split is the continuation of a settlement agreement in Docket No. UE 262. Parties agreed to this split in part based on the proposed construction of Cascade Crossing. This project has been canceled.

Q. Please describe Staff's recommendation regarding transmission marginal cost

A. Staff is still reviewing the factors driving the Company's investment in future transmission and might have relevant modifications on this issue in future.

Q. Does this conclude your direct testimony?

A. Yes.

CASE: UE 283
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME:	Suparna Bhattacharya
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	Utility Economist Energy – Rates, Finance, and Audit Division
ADDRESS:	3930 FAIRVIEW INDUSTRIAL DR. SE SALEM, OREGON 97302-1166
EDUCATION:	B.A. Economics Sambalpur University, India Specialization: Mathematical Economics
	M.S. Agricultural Economics University of Nebraska, Lincoln Specialization: Statistics, Econometrics
	Ph.D. Agricultural Economics University of Nebraska, Lincoln Specialization: Industrial Organization, Environmental & Natural Resource Economics, Production and Development Economics
EXPERIENCE:	I have been employed as a Utility Economist at the Public Utility Commission since April, 2014. My current responsibilities include load forecasting and analyzing marginal generation and transmission costs.

CASE: UE 283
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Exhibits in Support
Of Opening Testimony

June 11, 2014

May 6, 2014

TO: Nadine Hanhan
nadine@oregoncub.org
dockets@oregoncub.org

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to CUB Data Request No. 029
Dated April 23, 2014

Request:

In UE 283 PGE/1400/Cody/3, the Company describes the proxy method for the marginal cost of generation. In light of the RPS, please explain why wind generation is not used in this calculation. In addition, if wind generation were used, how would the Company propose integrating wind production into the marginal cost of generation?

Response:

PGE did not use wind generation in its generation marginal cost analysis because it wished to provide an analysis consistent with the UE 262 stipulation. This stipulation did not include wind generation in the calculation.

If wind generation were used in the generation marginal cost study, PGE would propose that a peaking resource such as an LMS 100 be used to provide the necessary capacity support for the portion of the marginal energy costs attributed to wind generation. This LMS 100 peaking resource would be more expensive than the more standard peaking resource used to determine the capacity portion of the thermal marginal generation costs.

Attachment 029-A contains a hypothetical example of how one could incorporate wind generation into a marginal cost analysis consistent with the Renewable Portfolio Standard (RPS). This example incorporates the RPS requirements by year over the time period 2015-2034 and the cost of thermal capacity and energy as well as the cost of wind which is treated as an energy resource. The result is a weighted cost of marginal capacity and energy.

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UE 283

Attachment 029-A

Provided in Electronic Format only

Hypothetical Weighted Marginal Generation Costs

	a	b	c	d	e	f=a x (1-e)+b x e	g=c x (1-e)+d x e
Year	Thermal Capacity SCCT $/kW-year	Wind Capacity Resource $/kW-year	Thermal Marginal Energy $/MWh	Wind Marginal Energy $/MWh	RPS	Weighted Capacity Costs $/kW-year	Weighted Marginal Energy $/MWh
2015	100.00	180.00	50.00	67.00	15.00%	112.00	52.55
2016	101.93	183.47	50.97	68.29	15.00%	114.16	53.56
2017	103.90	187.02	51.95	69.61	15.00%	116.36	54.60
2018	105.90	190.62	52.95	70.95	15.00%	118.61	55.65
2019	107.95	194.30	53.97	72.32	15.00%	120.90	56.73
2020	110.03	198.05	55.01	73.72	20.00%	127.63	58.76
2021	112.15	201.88	56.08	75.14	20.00%	130.10	59.89
2022	114.32	205.77	57.16	76.59	20.00%	132.61	61.05
2023	116.52	209.74	58.26	78.07	20.00%	135.17	62.22
2024	118.77	213.79	59.39	79.58	20.00%	137.78	63.42
2025	121.07	217.92	60.53	81.11	25.00%	145.28	65.68
2026	123.40	222.12	61.70	82.68	25.00%	148.08	66.95
2027	125.78	226.41	62.89	84.28	25.00%	150.94	68.24
2028	128.21	230.78	64.11	85.90	25.00%	153.85	69.55
2029	130.69	235.23	65.34	87.56	25.00%	156.82	70.90
2030	133.21	239.77	66.60	89.25	25.00%	159.85	72.27
2031	135.78	244.40	67.89	90.97	25.00%	162.93	73.66
2032	138.40	249.12	69.20	92.73	25.00%	166.08	75.08
2033	141.07	253.93	70.54	94.52	25.00%	169.28	76.53
2034	143.79	258.83	71.90	96.34	25.00%	172.55	78.01
Real Levelized	$100.00	$180.00	$50.00	$67.00		$116.23	$53.45
NPV	$1,285	$2,313	$643	$861		$1,494	$687
Nominal Levelized	$116.03	$208.85	$58.01	$77.74		$134.86	$62.02
Real Levelized	$100.00	$180.00	$50.00	$67.00		$116.23	$53.45

Composite Income Tax Rate			39.94%
Property Tax Rate			1.50%
Inflation Rate			1.93%
Capitalization:			
Preferred	0.00%	0.00%	0.00%
Common	50.00%	9.75%	4.88%
All Equity	50.00%		4.88%
Debt	50.00%	5.19%	2.60%
Cost of Capital			7.47%
After-Tax Nominal Cost of Capital			6.43%
After-Tax Real Cost of Capital			4.42%

CASE: UE 283
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 803

Exhibits in Support
Of Opening Testimony

<u>REDACTED</u>

June 11, 2014

STAFF EXHIBIT 803

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 14-043. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 283 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 283
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 804

Exhibits in Support
Of Opening Testimony

REDACTED
June 11, 2014

STAFF EXHIBIT 804

IS CONFIDENTIAL AND SUBJECT TO PROTECTIVE ORDER NO. 14-043. YOU MUST HAVE SIGNED APPENDIX B OF THE PROTECTIVE ORDER IN DOCKET UE 283 TO RECEIVE THE CONFIDENTIAL VERSION OF THIS EXHIBIT.

CASE: UE 283
WITNESS: SUPARNA BHATTACHARYA

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 805

Exhibits in Support
Of Opening Testimony

June 11, 2014

Marginal Energy Cost Allocations Across Schedules

Schedule	Busbar Energy (MWh)	Marginal Energy Cost
Schedule 7	7969632.538	$434,149,493.59
Schedule 15	17066.082	$814,479.55
Schedule 32	1666742.344	$89,055,363.54
Schedule 38	46550.51034	$2,571,518.18
Schedule 47	19501.85383	$1,077,665.70
Schedule 49	73837.37825	$4,030,236.44
Schedule 83	2932325.205	$157,788,004.70
Schedule 85	2344524.39	$125,009,444.14
Schedule 85 1-4 MW	927959.094	$49,084,086.08
Schedule 89	1164883.064	$60,476,130.01
Schedule 90	1539062.696	$79,658,201.88
Schedule 91	103744.9401	$4,951,232.09
Schedule 92	3546.548104	$182,758.21
Totals	18809376.64	$1,008,848,614.08

CASE: UE 283
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

June 11, 2014

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

A. My name is Jorge Ordonez. I am employed by the Public Utility Commission of Oregon (OPUC) as a Senior Financial Economist in the Energy Resources and Planning Section. My business address is 3930 Fairview Industrial Dr. SE Salem, Oregon 97302-1166.

Q. Please describe your educational background and work experience.

A. My Witness Qualifications Statement is found in Exhibit Staff/901, Ordonez /1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review Portland General Electric's (PGE or Company) request that the OPUC include in rates the costs[1] associated with the Port Westward 2 power plant (PW2 Power Plant or PW2 Project) and the Tucannon River wind farm (Tucannon River Wind Farm or Tucannon River Project) when they are placed in service.[2]

My review focused on the prudence of pursuing the projects, and the reasonableness of granting tariff riders to PGE.

In conducting the aforementioned review, Staff referred to the Company's initial filing and approximately 40 initial and follow up data requests.

Q. Did you prepare an exhibit for this docket?

A. Yes, I have prepared Exhibit Staff/901; Witness Qualification Statement; and Exhibit Staff/902; Staff-Proposed Conditions to Grant PGE Tariff Riders.

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[1] By "costs," Staff refers to the "net costs" of the Port Westward 2 power plant and the Tucannon River wind farm, which result after considering the dispatch benefits of the plants.
[2] See Exhibit PGE/400, Pope - Lobdell/23, line 9.

SUMMARY RECOMMENDATION

Q. What are your summary findings and recommendations?

A. Staff is still investigating the prudence of pursuing the PW2 and Tucannon River projects.

Regarding the reasonableness of granting tariff riders to PGE, Staff finds that if the Commission concludes the projects are prudent, granting PGE tariff riders for including in rates the costs associated with the projects when placed in service is reasonable. PGE's request for the tariff riders is similar to the request made in PacifiCorp's 2012 Rate Case for the Mona-to-Oquirrh transmission project (M2O Transmission Line). In that case, the Commission granted the Company's request.[3]

If the Commission grants PGE's request for the tariff riders, Staff recommends that the Commission do so subject to the conditions shown in columns B and C of Exhibit Staff/902.

TESTIMONY ORGANIZATION

I. PGE's request
II. Historical treatment
III. Analysis
IV. Findings and recommendations

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[3] PGE's request for the tariff riders is similar to that of PacifiCorp in PacifiCorp 2012 Rate Case in the following ways: (1) the PGE 2014 Rate Case was filed on February 13, 2014, with a 2015 test period, and (2) PGE anticipates that the PW2 Power Plant and Tucannon River Wind Farm will be placed in service during the test year.

I. PGE'S REQUEST

Q. What is the Company's request?

A. As shown in several parts of the Company's Direct Testimony,[4] PGE requests that the OPUC authorize tariffs for the Company to include in rates the costs associated with the PW2 Power Plant and the Tucannon River Wind Farm when they are placed in service.

Q. Please provide a brief description of the PW2 power plant and the Tucannon River Wind Farm.

A. The PW2 Power Plant is located in Columbia County in the State of Oregon[5] and consists of 12 natural gas reciprocating engines, with a combined capacity of approximately 220 MW, that are designed to provide flexible capacity.[6, 7]

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[4] The following are the parts where PGE requested the OPUC to authorize the tariffs:

- In page 2 of PGE's Executive Summary filed concurrently with its Direct Testimony, the Company represented: "*In accordance with past Commission practice, PGE requests that the new plants be incorporated into customer prices when they begin service to customers.*"
- In page 5 of *Id.*, the Company represented: "*PGE's request with respect to the rate changes when the two new plants come on-line is consistent with past Commission practice. As has been done in previous dockets, when each of the plants is on-line, PGE will provide an attestation of a PGE officer verifying that the plant is in operation and available for service to customers. PGE requests that after the filing of such an attestation, rates including the costs of each plant become effective.*"
- In page 4 of *Id.*, the Company represented: "*"PGE seeks a schedule in this docket that will allow for a Commission order by mid-December and revised tariff schedules implemented on January 1, 2015, with additional price changes implemented when PW2 and Tucannon begin service to customers.*"
- In Exhibit PGE/300, Tooman-Mcfarlane/2, lines 10-15 the Company represented: "*PGE requests that the Public Utility Commission or Oregon (OPUC) authorize tariffs to collect these annualized amounts beginning with the on-line date of each respective generating plant. We currently expect PW2 to be on-line in the first quarter of 2015 and Tucannon to be on-line in the first part of 2015. To the extent that the on-line date for either plant changes, the effective date of tariffs to recover the incremental impact of the plant changes accordingly.*"

[5] See Exhibit PGE/400, Pope - Lobdell/23, line 9.

[6] See Exhibit PGE/400, Pope - Lobdell/17, lines 2-5.

[7] Flexible capacity is the generating capacity that can quickly follow the changes of intermittent generation and variable load.

The Tucannon River Wind Farm is located in Columbia County in the State of Washington and consists of 116 wind turbines with a combined capacity of approximately 267 MW.[8]

Q. When does PGE expect to place these projects in service?

A. In its Direct Testimony, the Company represented that it anticipates the in-service dates to be the first quarter of 2015 for the PW2 Power Plant[9] and the first half of 2015 for the Tucannon River Wind Farm.[10] In subsequent filings, PGE represented that it anticipates that the Tucannon River Wind Farm will be placed in service before the first quarter of 2015.[11, 12]

Q. What is the basis by which the company claims its request is reasonable?

A. In its Direct Testimony, the Company represents that its request "is consistent with past Commission practice."[13]

As for the PW2 Power Plant, the Company represents that "[t]he 2009 IRP action plan identified the need for approximately 200 MW of flexible capacity"[14] and that "[t]he ensuing 2012 RFP resulted in the selection of the PW2 project as the least cost, least risk bid."[15]

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[8] See Exhibit PGE/400, Pope - Lobdell/11, lines 2-5.
[9] See Exhibit PGE/400, Pope - Lobdell/24, lines 4-5.
[10] See Exhibit PGE/400, Pope - Lobdell/14, lines 12-13.
[11] See PGE's filing with the Securities and Exchange Commission on March 31, 2015 at http://investors.portlandgeneral.com/secfiling.cfm?filingID=784977-14-22
[12] Also see PGE response to Staff Data Request 004, part "a" in Docket No. UE 286.
[13] In page 5 of *Id.*, the Company represented: *"PGE's request with respect to the rate changes when the two new plants come on-line is consistent with past Commission practice. As has been done in previous dockets, when each of the plants is on-line, PGE will provide an attestation of a PGE officer verifying that the plant is in operation and available for service to customers. PGE requests that after the filing of such an attestation, rates including the costs of each plant become effective."*
[14] See Exhibit /PGE/400, Pope - Lobdell/2, lines 19-20.
[15] See Exhibit PGE/400, Pope - Lobdell/3, lines 3-4.

As for the Tucannon River Wind Farm, the Company represents that "PGE's 2009 Integrated Resource Planning (IRP) action plan identified the need for 122 MWa of renewable energy"[16] and that "PGE conducted an RFP that resulted in the selection of Tucannon as the least cost, least risk bid."[17] In Exhibit PGE/400, Pope - Lobdell/4-10, the Company further described how the RFP process that resulted in the selection of both projects was conducted, including the participation of an Independent Evaluator (IE).

Q. What are the expected costs of the projects?

A. In its Direct Testimony, the Company represents that the capital expenditures for PW2 Power Plant total approximately $300 million[18] and that the capital expenditures for the Tucannon River Wind Farm total approximately $500 million.[19]

II. HISTORICAL TREATMENT OF THIS KIND OF REQUEST

Q. What is the latest ruling regarding this kind of request?

A. In Order No. 12-493 of Docket No. UE 246 (PacifiCorp 2012 Rate Case), the OPUC granted PacifiCorp a tariff rider to recover the costs of the M2O Transmission Line.[20] Regarding this docket, it should be noted that:

- The PacifiCorp 2012 Rate Case was filed on March 1, 2012, with a 2013 test period;

[16] See Exhibit PGE/400, Pope - Lobdell/2, lines 3-4.
[17] See Exhibit PGE/400, Pope - Lobdell/2, lines 5-6.
[18] See Exhibit PGE/400, Pope - Lobdell/24, line 3.
[19] See Exhibit PGE/400, Pope - Lobdell/14, line 12.
[20] See pages five to eight of Order No. 12-493 of Docket No. UE 246 at http://apps.puc.state.or.us/orders/2012ords/12-493.pdf

- At the time of filing, PacifiCorp anticipated the M2O Transmission Line to be placed in service in May 2013;
- Parties in the PacifiCorp 2012 Rate Case stipulated that the investment was prudent, but disagreed on whether the Commission should grant PacifiCorp the tariff rider; and
- In Order No. 12-493, the OPUC granted PacifiCorp the tracker, because the OPUC had previously acknowledged the transmission line as part of the utility's IRP process and other parties had stipulated to the prudence of the investment with the conditions represented in column A of Exhibit Staff/902.

III. ANALYSIS

PRUDENCE OF THE DECISION TO PURSUE THE PROJECTS

Q. What standard does the Commission use to determine whether an investment is prudent?

A. A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the task that confronted the company."[21]

Q. Is Staff analyzing the prudence of the company's pursuit of these projects?

A. Yes. For the PW2 Power Plant, PGE's 2009 IRP (Docket No. LC48) identified an action plan regarding the need for approximately 200 MW of flexible capacity, which was acknowledged in Order No. 10-457.[22] The 2012 RFP in Docket No. UM 1535 resulted in the selection of the PW2 project as the least-cost, least-risk bid.

As for the Tucannon River Wind Farm, PGE's 2009 IRP (Docket No. LC 48) identified an action plan regarding the need for 122 MWa of renewable energy to physically meet the 2015 Renewable Portfolio Standard (RPS) target. Order No. 10-457 in Docket No. LC 48 acknowledged PGE 2009 IRP.[23] PGE's 2009 IRP Update adjusted the need for renewable energy from 122 MWa to 101 MWa. Finally, PGE's 2012 RFP in Docket No. UM1613 resulted in the selection of the Tucannon River Wind Farm.

Staff continues to analyze the prudence of the decision to invest in the projects (e.g., the wind integration aspects of PW2 Power Plant's flexible capacity) as well as the costs and benefits of this project that may be included in the requested tariff riders.

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[21] Order No. 12-493 at 18 (UE 246).
[22] See page 30 of the referenced order at http://apps.puc.state.or.us/orders/2010ords/10-457.pdf
[23] *Id.*

Staff is also reviewing the Company' responses to data requests regarding the actual and anticipated costs of the project, and benefits of the project such as a reduction to net variable power costs including wind integration costs.[24] In addition to reviewing those costs, and since the plants are not expected to be completed for yet another several months, there are costs not yet incurred and so staff is not able to speculate on the reasonableness of those costs yet to be incurred.

REASONABLENESS OF GRANTING TARIFF RIDERS TO PGE

Q. Has Staff analyzed the reasonableness of granting tariff riders to PGE?

A. Yes. PGE's request for the tariff riders is similar to that of PacifiCorp in PacifiCorp 2012 Rate Case in the following ways: (1) the PGE 2014 Rate Case was filed on February 13, 2014, with a 2015 test period, and (2) PGE anticipates that the PW2 Power Plant and Tucannon River Wind Farm will be placed in service during the test year.

In other words, in PacifiCorp and PGE cases, the in-service date of the projects was during the test year.

Q. Does the projects' in-service dates during the test year represent an impediment for granting the tariff riders to PGE?

A. No. In Order No. 12-493 of Docket No. UE 246 (PacifiCorp 2012 Rate Case), the OPUC granted PacifiCorp a tariff rider and represented that "[u]nder similar

[24] For example, in Docket No. UE 286 (PGE's Net Variable Power Costs), the Industrial Customers of Northwest Utilities raised issues about the reasonableness of the Company-proposed wind integration benefits of the PW2 Power Plant, transmission credits of the Tucannon River Wind Farm, and capacity factor of the Tucannon River Wind Farm.

circumstances, this Commission has previously allowed utilities to recover in rates the costs of investments placed into service during the test year."[25]

REASONABLENESS OF GRANTING TARIFF RIDERS TO PGE

Q. What are Staff's findings and recommendation about the reasonableness of granting tariff riders to PGE?

A. Staff finds that granting tariff riders for recovering the costs of the PW2 Power Plant and Tucannon River Wind Farm is reasonable and therefore recommends that the OPUC grant PGE's request for tariff riders if it concludes that the projects are prudent.

In accordance with a recommended condition proposed in Exhibit Staff/902, parties will have the opportunity to audit and review of the utility's final costs and benefits of the plants (Audit of Final Costs).

And, while according to PGE the probability is remote, PGE should be required to make a new filing for cost recovery for either plant should such plant fail to be placed into service by July 1, 2015.

Q. What other matter, if any, would you like to address?

A. Staff anticipates that other parties will file testimony regarding PGE's request. Staff reserves the opportunity to address this testimony in its next round of testimony.

Q. Does this conclude your testimony?

A. Yes.

[25] See page 7 of Order No. 12-493 of Docket No. UE 246.

CASE: UE 283
WITNESS: Jorge Ordonez

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME	Jorge D. Ordonez
EMPLOYER	Public Utility Commission of Oregon
TITLE	Senior Financial Economist, Energy Resources and Planning Section
ADDRESS	3930 Fairview Industrial Dr SE, Salem, Oregon 97302-1166
EDUCATION AND TRAINING	Utility Management Certificate Willamette University, Oregon, 2008 Certificate in Management of Hydropower Development Swedish International Development Cooperation Agency, Sweden, 2006 & South Africa, 2007 Fulbright Scholar, MBA, concentration in finance Willamette University, Oregon, 2005 Certificate in Project Appraisal and Management Maastricht School of Management, Netherlands, 2002 BS, Mechanical Engineering, thermal power efficiency Electrical & Mechanical Engineering School San Antonio Abad University, Peru, 1998
EXPERIENCE	I received a Bachelors of Science degree in Mechanical Engineering from San Antonio Abad University in Cusco, Peru in 1998. Subsequently, as a Fulbright Scholar, I received an MBA with an emphasis in finance from Willamette University in 2005. From 1999 to 2008, I worked for a Peruvian power generation company and was promoted many times, working as an Engineer, Resource Scheduler, Manager of Economic Planning and Vice-President of Generation, Commercial and Trading. Since January 2009, I have been employed by the Public Utility Commission of Oregon as a Senior Financial Economist, evaluating utilities' issuance of securities, cost of capital, mergers and acquisitions, cost of service studies, marginal cost studies, rate spread and rate design, integrated resource plans, purchased natural gas costs, and power costs.

CASE: UE 283
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

June 11, 2014

CONDITIONS					
Column A		Column B		Column C	
UE246 OPUC Conditions[1] for the M2O Transmission Project		UE283 Staff Proposed Conditions for the PW2 Power Plant		UE283 Staff Proposed Conditions for the Tucannon River Wind Farm	
Scenario 1: The M2O Transmission Project becomes operational by May 31, 2013	**Scenario 2**: The M2O Transmission Project becomes operational after May 31, 2013	**Scenario 1**: The PW2 Power Plant becomes operational by March 31, 2015	**Scenario 2**: The PW2 Power Plant becomes operational after March 31, 2015	**Scenario 1**: The Tucannon River Wind Farm becomes operational by March 31, 2015	**Scenario 2**: The Tucannon River Wind Farm becomes operational after March 31, 2015
PacifiCorp will [provide][2] an attestation by a corporate officer that the project is complete and has been released for operation (Attestation).	If the transmission project becomes operational after May 31, 2013, but within 60 days of May 31, 2013, Staff and intervenors will have 20 days from the online date to establish sufficient cause to warrant the reopening of this docket to determine whether any cost reductions to PacifiCorp's test year expenses should be used to off-set, in part, costs associated with the new transmission project.	PGE will provide an attestation by a corporate officer that the project is complete and has been released for operation (Attestation).	If the PW2 Power Plant becomes operational after March 31, 2015, but within 60 days of March 31, 2015, Staff and intervenors will have 20 days from the online date to establish sufficient cause to warrant the reopening of this docket to determine whether any cost reductions to PGE's test year expenses should be used to off-set, in part, costs associated with the new plant.	PGE will provide an attestation by a corporate officer that the project is complete and has been released for operation (Attestation).	If the Tucannon River Wind Farm becomes operational after March 31, 2015, but within 60 days of March 31, 2015, Staff and intervenors will have 20 days from the online date to establish sufficient cause to warrant the reopening of this docket to determine whether any cost reductions to PGE's test year expenses should be used to off-set, in part, costs associated with the new plant.
The OPUC will review for prudence the final costs of the transmission project before they are included in rates (Prudence of Final Costs).		The OPUC will review for prudence the final costs and reasonableness of benefits of the plant before they are included in rates (Prudence of Final Costs).		The OPUC will review for prudence the final costs and reasonableness of benefits of the plant before they are included in rates (Prudence of Final Costs).	
PacifiCorp will facilitate the parties' audit and review of the utility's final costs of the project, and any party may challenge costs as imprudent or exceeding the amount initially requested by PacifiCorp (Audit of Final Costs).	If the transmission project becomes operational more than 60 days after May 31, 2013, PacifiCorp must make a new filing with the Commission under ORS 757.210 to add the project to rate base when it meets the used and useful standard.	PGE will facilitate the parties' audit and review of the utility's final costs and benefits of the plant. Any party may challenge costs or benefits as imprudent, unreasonable, or exceeding the cost amount that resulted of the RFP in which this plant was selected (Audit of Final Costs).	If the PW2 Power Plant becomes operational more than 60 days after March 31, 2015, PGE must make a new filing with the Commission under ORS 757.210 to add the project to rate base when it meets the used and useful standard.	PGE will facilitate the parties' audit and review of the utility's final costs and benefits of the plan. Any party may challenge costs or benefits as imprudent, exceeding the amount of the plant as a result of the RFP in which this project was selected, or unreasonable (Audit of Final Costs).	If the Tucannon River Wind Farm becomes operational more than 60 days after March 31, 2015, PGE must make a new filing with the Commission under ORS 757.210 to add the project to rate base when it meets the used and useful standard.

[1] See Docket No. UE 246, Order No 12-493, page 8 at http://apps.puc.state.or.us/orders/2012ords/12-493.pdf.
[2] Although Order No. 12-493 of Docket No. UE 246 uses the word "need," Staff uses the words "provide".

CASE: UE 283
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1000

Opening Testimony

June 11, 2014

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

A. My name is Judy Johnson. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Staff's review and recommendations on PGE's environmental remediation costs.

Q. Did you prepare an exhibit for this docket other than your witness qualification statement?

A. No.

Q. What position does PGE take when discussing environmental remediation costs?

A. The Company asks for approval from the Commission to reclassify all environmental remediation costs as a regulatory asset, which it would then amortize over 20 years.

Q. Does the Staff agree with PGE's solution to recovering these costs?

A. No. Given the early stages of the process of PGE's environmental remediation responsibilities and costs, it is premature to adopt PGE's proposal.

Q. Does PGE have an estimation of its share of environmental remediation costs?

A. The Company has an estimation of 2014 and 2015 cost, which it identifies only by Operating Area, not remediation site. PGE's estimate of its 2014 costs is $6.19 million and its 2015 costs at $9.31 million.

Q. Why does PGE not have an estimate of its share of environmental remediation costs for specific areas or projects?

A. At this time, PGE states in its Response to ICNU Data Request No. 53, that remediation costs for the federal Environmental Protection Agency (EPA)-governed Portland Harbor Superfund site have not yet been determined. A Record of Decision is expected from the EPA in late 2015 on the various clean-up alternatives; which could take up to 28 years to complete and range in cost from $169 million to $1.8 billion.

Q. Has PGE done all it can to collect insurance monies for environmental remediation costs?

A. At this time, PGE has notified all its insurers that these environmental remediation costs are coming. At this point, without knowing the full extent of its liabilities, PGE is not and should not be trying to collect insurance monies without more information.

Q. At this juncture what does Staff recommend?

A. Some of PGE's insurers are paying a portion of the Company's defense and investigation of environmental costs. If the insurers are not paying a sufficient amount to cover the Company's defense and investigation of environmental costs, the Company should apply to defer these costs for later amortization after all efforts have been exhausted to get monies from insurers.

Q. Does PGE include any environmental remediation costs into its revenue requirement for 2015?

A. Yes. PGE includes $3.1 million in the 2015 Test Year revenue requirement to cover its cost of defense and investigation in this initial stage of environmental remediation. Staff has removed the $3.1 million of expenses and recommends that the Company seek a deferral for costs it cannot recover from its insurers.

Q. Please summarize Staff's recommendations regarding PGE's environmental remediation costs.

A. Staff recommends that PGE's request to put $3.1 million into base rates be denied. The Company can apply for a deferral of excess costs associated with environmental costs.

Staff recommends that PGE's request for an accounting order to establish a regulatory asset with a 20-year amortization for environmental remediation efforts be denied until more information is available regarding PGE's projected environmental remediation costs.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 283
WITNESS: JUDY JOHNSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME:	JUDY A. JOHNSON
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR ECONOMIST IN ENERGY, RATES, FINANCE, AND AUDIT
ADDRESS:	3930 FAIRVIEW INDUSTRIAL DR. SE, SALEM, OREGON 97308-1088
EDUCATION:	MBA with an emphasis in Statistics from Eastern Washington University Cheney, Washington BA in Accounting from Eastern Washington University Cheney, Washington
EXPERIENCE:	

3/95-Present	I have been employed by the Oregon Public Utility Commission since March of 1995. My current position is as a Senior Economist in Energy, Rates, Finance, and Audit. I was previously a Program Manager of Rates & Tariffs.
6/77-2/95	I was employed by Avista Corporation, an electric and natural gas utility located in Spokane, Washington. The majority of my employment was spent in the Rates and Regulatory Affairs Department as a Senior Rate Analyst. I have prepared testimony and exhibits in numerous electric and natural gas rate cases, primarily in the area of results of operations and cost of service.

CASE: UE 283
WITNESS: Ryan Bracken

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

REDACTED
June 11, 2014

CERTAIN INFORMATION CONTAINED IN STAFF EXHIBIT 1100

PAGES 13 TO 18, 22, 25 AND 26

ARE CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 14-043. YOU

MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 283 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

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

A. My name is Ryan Bracken. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088. I am employed by the Oregon Public Utility Commission (OPUC) as a Senior Economist.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. To review and analyze PGE's proposal to "carve out" the variance in Net Variable Power Costs (NVPC) attributable to the Renewable Portfolio Standard (RPS) for 100% pass through.

Q. Did you prepare an exhibit for this docket?

A. Yes. In addition to Exhibit Staff/1101 I prepared Exhibit Staff/1102 consisting of 4 pages, Exhibit Staff/1103 consisting of 17 pages, and Exhibit Staff/1104 consisting of 1 page.

SUMMARY RECOMMENDATIONS

Q. What are your summary findings and recommendations?

A. Some NVPC variance is attributable to the RPS. However, PGE's proposed RPS carve out should not be adopted as it runs contrary to the intent of Senate Bill 838 (SB 838, RPS Bill, or Bill), which the Company cites to justify its proposal. That being said, if the Commission decides to adopt an RPS carve out, a suitable calculation methodology is required. PGE's proposed calculation methodology has major flaws and Staff recommends that an alternate methodology be used in the event the Commission adopts an RPS carve out. Staff proposes four alternative calculation methodologies that improve upon PGE's methodology and recommends its preferred method.

TESTIMONY ORGANIZATION

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1: Clarifying PGE's RPS Carve Out Proposal

Q. What is NVPC variance?

A. NVPC variance is the difference between what is collected from customers for NVPC and the costs actually incurred. As the name implies, NVPC are the variable portion of costs, such as fuel costs and market purchases. If in a given year the Company collects $500 million from customers for NVPC but incurs costs of only $450 million, then the $50 million difference is the NVPC variance. NVPC variance can be either an overcollection or an undercollection.

Q. What is the current OPUC mechanism to determine NVPC and the NVPC variance to be trued up for PGE?

A. PGE projects what NVPC will be in the coming year using their hourly production cost model MONET in the Annual Update Tariff (AUT). The Commission uses this projection to set the NVPC rates for the upcoming year. After the year in question has passed, the Power Cost Adjustment Mechanism (PCAM) is used to calculate the variance between what was collected (i.e. the rate set in the AUT * actual load) and what costs were actually incurred by PGE. This variance is then subject to the deadband, sharing, and an earnings test.

If PGE overcollects less than $15 million or undercollects less than $30 million then all NVPC variance falls within the deadband and no true-up is necessary. However, if the variance is an overcollection in excess of $15 million or a undercollection in excess of $30 million, then the excess amount is subject to

90/10 customer-shareholder sharing. The customers' 90% is then subject to an earnings test. Any variance that remains after the earnings test is trued up through amortization.

Q. Why does this mechanism to true-up NVPC matter for the RPS carve out?

A. It is PGE's interpretation of the RPS statute that 100% of the costs attributable to the resources acquired by the Company to comply with the RPS (RPS resources) must be recovered in rates, including those that are part of NVPC.[1] Since NVPC variance is subject to the deadband, sharing, and an earnings test if RPS resources contribute to NVPC variance PGE is not recovering all costs attributable to the RPS.

Q. Do the resources acquired by PGE to comply with the RPS contribute to the variance in NVPC?

A. Yes. Even though MONET models RPS resources as having zero variable costs,[2] RPS resources do contribute to the *variance* in NVPC because they are intermittent resources. To the extent RPS resources generate electricity, those resources displace the need to meet native load with other resources.

Q. How do intermittent generation resources contribute to NVPC variance?

A. For simplicity, assume that PGE has only one generation resource: an RPS qualifying wind farm. In this scenario, if PGE's load is greater than the generation of its wind farm it needs to purchase the shortfall to serve its load in the wholesale power market, whereas if PGE's load is less than the generation

[1] See Exhibit UE 283/PGE/500, Niman-Peschka-Hager/43-47

[2] In setting the NVPC rate in the AUT there are, however, royalty cost and production tax credit adjustments to the power costs of RPS resources.

of the wind farm it can sell the extra power in the wholesale market. Since the wind farm is modeled in MONET as having zero net variable power costs, the only NVPC PGE would incur in this scenario are its net purchases on the wholesale power market. However, even though the NVPC directly attributable to the RPS wind farm are negligible, it contributes to the *variance* in NVPC because if the generation of the wind farm is not exactly equal to the amount forecasted the Company will need to purchase/sell more or less wholesale power to make up the difference. Since PGE needs to forecast the generation from the wind farm for each hour of the upcoming year to be able to set a rate for NVPC in the AUT, its generation forecast for the wind farm will not match reality in some (and likely nearly all) hours of the year.[3]

Continuing with the simple example, consider one hour of the year as depicted in Table 1 below as an illustration:

Table 1:	A	B	C	D	E
	Load (MWh)	Wind Farm Generation (MWh)	Purchases / Sales (MWh) (A-B)	Market Price ($/MWh)	NVPC ($) (C*D)
Forecast	100	80	20	$30	$600
Actual	100	50	50	$30	$1,500
			Total NVPC Variance		$900

In this hour the Company forecasted the load and the market price of power correctly, so the only difference between what was forecasted and what materialized in reality is the generation of the wind farm. As shown, the Company projected wind generation to be 80 MWh in this hour, but the wind

[3] Forecasting hourly wind generation next week is not reliable, so forecasting hourly wind generation for periods that are 2-14 months in the future is going to introduce a large amount of forecast error.

farm only generated 50 MWh in reality. Even though this does not result in a change in the NVPC of the wind farm since they are modeled to have zero variable power costs, the mis-forecast in wind generation did result in PGE puchasing 30 additional MWh of power on the wholesale market at a cost of $30/MWh. The end result is that actual power costs are $900 higher for the hour than forecasted due to the intermittent nature of the wind farm.[4] Assuming PGE was able to correctly forecast load and the market price of power for every other hour of the year, if the total NVPC variance for the year fell within the deadband, none of the variance attributable to the intermittent wind resource would be recovered/refunded by the Company, and if the total NVPC was greater than the deadband the Company would only recover/refund a portion of the variance attributable to the RPS resource.

Q. What does PGE propose?

A. PGE proposes to "carve out" the NVPC variance attributable to RPS resources from the total NVPC variance that is subject to the deadband, sharing, and an earnings test and true up 100% of the RPS resource attributed variance through the Renewable Resources Automatic Adjustment Clause (RAC). This would leave the total NVPC variance net of the RPS carve out (i.e. the non-RPS attributed portion of the variance) subject to the deadband, sharing, and an earnings test in the PCAM.

[4] Note that under-forecasting wind generation would result in an overcollection

Q. Is it possible to accurately carve out the NVPC variance that is attributable to RPS resources from variance that is not attributable to RPS resources?

A. No. In reality there are a number of factors that contribute to NVPC variance in any given hour that cannot be separated due to their complex interrelated nature. However, there are methods that can be used to reasonably approximate the variance attributable to RPS resources, and these methods will be examined in Issues 3 and 4 of this testimony.

Q. Does it matter that the resources that PGE would have acquired if there were no RPS would also contribute to NVPC variance?

A. Even though the resources PGE would have acquired had the RPS not been implemented would also be contributing to NVPC variance if PGE had them in their portfolio instead of the RPS resources, the Company sees this as irrelevant. The Company interprets the RPS statute as guaranteeing the recovery of all prudently incurred costs associated with the RPS, including the variance in variable power costs.

Issue 2: The Legislative Intent of the RAC in the RPS Bill

Q. Is it clear that the RPS statute guarantees PGE the recovery of NVPC variance attributable to RPS resources?

A. No. Upon the advice of counsel as well as my own reading of the the RPS, I believe that the Company's interpretation of the statute is inconsistent with the intent of SB 838.

Q. Does PGE's testimony cite the only applicable portion of the RPS statute?

A. No. In SB 838 Subsection 13(1), the legislature specifies that "*all* prudently incurred costs associated with compliance with a renewable portfolio standard are *recoverable* in the rates of an electric company." SB 838 Subsection 13(1) is the portion of the statute cited by the Company to justify its RPS carve out proposal.

However, subsection 13(3) is the more relevant provision of SB 838. Subsection 13(3) directs the Commission to establish an automatic adjustment clause to allow timely recovery of a subset of the costs described in subsection 13(1), "costs prudently incurred by an electric company to *construct or otherwise acquire facilities* that generate electricity from renewable energy *and for associated transmission*." Similarly, Section 13a directs the Commission to establish a clause *applying to all prudently incurred costs described in Section 13(3)* no later than January 1, 2008. The clause described in the Bill was established by the Commission as directed, and is the aforementioned RAC that PGE proposes to use to true-up RPS related NVPC variance.

Even if "associated transmission" costs is interpreted very broadly and includes the costs of ancillary services, PGE's proposal to include RPS attributable NVPC in the RPS automatic adjustment clause would still be inconsistent with SB 838 section 13(3).[5]

Q. Is there additional evidence to support the conclusion that the RAC was not intended to apply to NVPC variances?

A. Yes. The legislative history in 2007 of Senate Bill 838 (the bill that became the RPS) indicates the legislature's intent as to what costs are to be recovered under the automatic adjustment clause (the RAC) created by section 13 and 13a.

Testimony before the House Committee on Energy and the Environment shows the SB 838 automatic adjustment clause was not intended to apply to the broad range of costs described in Section 13(1). In fact, Section 13a was amended by the House Committee to reference Subsection 13(3) in the enrolled version of the Bill instead of Subsection 13(1) as is found in SB 838 A-Engrossed.[6] Again, PGE uses SB 838 Subsection 13(1) to justify its proposed RPS carve out, when Subsection 13(3) (which does not support the Company's interpretation) is the more relevant provision.

Exhibit Staff/1102 details the relevant testimony before the House Committee on Energy and the Environment on what was intended- and what was not intended- to be recovered through the RAC and details the amendment to

[5] SB 838 Subsection 13 is codified at ORS 469A.120.

[6] SB 838 A-Engrossed is dated April 6, 2007, and the amendment was adopted by the House Committee on Energy and the Environment on April 30, 2007 and is present in the enrolled version of the Bill.

Section 13a to reference the narrower in scope Subsection 13(3) rather than the broader Subsection 13(1) cited by PGE.

Q. Should the Commission use its broad authority to true up RPS attributed NVPC variance in the RAC?

A. No. The legislative intent of the amended version of SB 838 is fairly clear that the RAC is not meant to be used to true up NVPC variances, even if the variance is attributable to the RPS. However, if the Commission decides it will allow the RAC to be used to true up RPS NVPC variance it should not adopt the calculation methodology proposed by PGE (see Issues 3 and 4 below).

Q. Does this mean the Commission should reject outright PGE's RPS carve out proposal?

A. Not necessarily. While the legislative history shows the legislature did not require that NVPC variances be trued up in the RAC, the Commission has discretion under SB 838 Subsection 13(1) to allow PGE to recover "prudently incurred costs associated with compliance with a renewable portfolio standard" that are not specifically described in Subsection 13(3) through other means. More specifically, Subsection 13(1) specifies that costs associated with compliance are recoverable in rates, but does not order the Commission to include them in rates. Presumably, therefore, the legislature left it to the Commission's discretion how to, and whether to, include these costs in rates. The legal authority of the Commission to exercise such discretion will be addressed in Staff's brief.

Q. If the Commission exercises its discretion to allow an RPS carve out to recover RPS related NVPC variance, is the RAC the appropriate mechanism to do so?

A. No. For the reasons detailed above, the RAC is not the appropriate mechanism to true up RPS related NVPC variance. There are other options that could be explored if an RPS carve out were adopted, including modifying the PCAM to directly incorporate the RPS carve out.

Issue 3: Analysis of PGE's Proposed RPS Carve Out Calculation Methodology

Q. What is PGE's proposed RPS carve out calculation methodology?

A. The Company's proposed calculation methodology is the crux of the technical portion of the proposal and is presented in Exhibit UE PGE/503, Niman-Peschka-Hager/1. The methodology for each resource can be summed up as follows:

$$\begin{aligned} &\textit{RPS resource NVPC variance} \\ &\quad = (\textit{Forecasted RPS resource generation} * \textit{Forecasted Market Price}) \\ &\quad - (\textit{Actual scheduled RPS resource generation} * \textit{Actual Market Price}) \end{aligned}$$

where the figures are adjusted for integration costs, royalty costs, and production tax credit (PTC) variance after the fact. Hourly figures are used for the Company's owned RPS resources while monthly averages are used for PGE's contracted RPS resources. Also note that for contracted resources the price portions of the calculation are the difference between the Mid-C price and the price for energy in the contract.[7]

Q. What would have PGE's proposed methodology meant for customers in the last few years had the proposed RPS carve out methodology already been in place?

[7] Note that for contracted RPS resources the cost of the electricity is the price in the contract, which is almost always higher than the market price of power (both forecasted and actual).

A. In general the total amount of NVPC variance to be trued up between the RAC and the PCAM would have been much larger than what was actually trued up in the PCAM under the current mechanism, as shown in the Table 2 below:[8]

Table 2			2011	2012	2013
Current NVPC Mechanism: No RPS carve out	A	Undercollection/(overcollection) of NVPC in PCAM	$ [redacted]	$ [redacted]	$ [redacted]
	B	Amount subject to sharing [charge/(refund)]	$ [redacted]	$ [redacted]	$ [redacted]
	C	Charge/(refund) to customers in PCAM before earnings test	$ [redacted]	$ [redacted]	$ [redacted]
	D	Actual charge/refund after application of earnings test	$ [redacted]	$ [redacted]	$ [redacted]
Proposed Mechanism: RPS Carve out and PCAM	E	Undercollection/(overcollection) in PCAM	$ [redacted]	$ [redacted]	$ [redacted]
	F	RPS Undercollection/(overcollection) to be trued-up in RAC	$ [redacted]	$ [redacted]	$ [redacted]
	G	Amount subject to sharing [charge/(refund)] in PCAM	$ [redacted]	$ [redacted]	$ [redacted]
	H	Charge/(refund) to customers in PCAM before earnings test	$ [redacted]	$ [redacted]	$ [redacted]
	I	Actual charge/refund after application of earnings test	$ [redacted]	$ [redacted]	$ [redacted]
	J	Total charge/(refund) to customers from NVPC (PCAM&RAC)	$ [redacted]	$ [redacted]	$ [redacted]
Change in NVPC amount "trued-up" between current PCAM mechanism and PGE's proposal for combination of adjusted PCAM and "RPS carve-out"			$ [redacted]	$ [redacted]	$ [redacted]

* values are in 1000's of dollars

From Table 2 it can be seen that in 2011 PGE overcollected $[redacted] million (row A), exceeding the deadband of $15 million. Therefore $[redacted] - $[redacted] = $[redacted] million was subject to 90%/10% sharing (row B). This means that $[redacted] million ($[redacted]*0.9=$[redacted]) was subject to the earnings test (row C). To get within 100 basis points of authorized ROE the Company was only required to refund $[redacted] million (row D) of the total $[redacted] million that was overcollected.[9] Had the RPS carve out been in place at the time rather than the current mechanism it would have resulted in an RPS resource undercollection (i.e. RPS "carve out") of $[redacted] million to be trued up as a charge to customers in the RAC (row F). Per PGE's proposal the RPS carve out would be netted out of total NVPC variance to obtain the amount to be trued up in the PCAM. Note (as

[8] This table was compiled and calculated using data found in the responses to OPUC DR No.s 471 and 475, which can found in Exhibit/Staff 1103.

[9] This is the amount that would be amortized in the next calendar year and is subject to interest charges.

mentioned above) for 2011 there was a total NVPC overcollection of $[redacted] million, which means that the total variance was an overcollection and the RPS carve out using PGE's proposal would have been an undercollection. Consequently, when one subtracts the RPS carve out (a positive number) from the already negative total NVPC variance, the result is a more negative figure.[10] This net out would have left a $[redacted] million overcollection in the PCAM[11] subject to the deadband, sharing, and an earnings test (row E). In this case $[redacted] - $[redacted] = $[redacted] million would have been subject to sharing (row G) and $[redacted] million would have been subject to the earnings test (row H). Furthermore, the Company would be required to refund $[redacted] (row I) of the $[redacted] million after the earnings test.

Therefore, if the RPS carve had been in place during the true up of calendar 2011 the Company would have added a *charge* of $[redacted] million to customer bills through the RAC and $[redacted] million would have been *refunded* through the PCAM for a total refund of $[redacted] million ($[redacted] - $[redacted] = $[redacted] million, seen in row J).

Comparing this result to the actual results from the PCAM only mechanism currently in place, there would have been an additional $[redacted] million refunded between the RAC and the PCAM for the 2011 calendar year (bottom row) had the RPS carve out as proposed by the Company been in place ($[redacted] million

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[10] Therefore, presumably, the Company is saying that without the RPS the overcollection would have been much larger. Staff takes issue with this interpretation, as detailed in Issue 3 below.

[11] Note that $[redacted] +$[redacted] is not exactly $[redacted] million as there are small after the fact adjustments made to the PCAM.

that would have been refunded had the RPS carve out been in place – the $[redacted] million that was refunded with the current mechanism = $[redacted] million).

Note that in 2012 and 2013 the RPS carve out would have led to a large additional charge to customers rather than an additional refund.

Q. Does this exacerbation of NVPC variance being trued up under the RPS carve out proposal (RAC and PCAM) in comparison to the current PCAM only mechanism appear to be a trend?

Yes. As the bottom row of Table 2 shows, in each 2011, 2012, and 2013 there would have been a much larger amount amortized and charged/refunded to customers had PGE's proposed RPS carve out been in place. For calendar 2012,[12] there would have been an additional $[redacted] million amortized and charged to customers under the Company's proposal than was actually trued up under the current PCAM only mechanism.

The average amount to be amortized as a refund or charge under the current mechanism was $[redacted] million (average row D), while the average would have been $[redacted] million annually if the RPS carve out as proposed by PGE had been in place.

Furthermore, on average for the 3 years in question, the end result for customers would have been an additional charge (not refund) of $[redacted] million per true up year.

Q. Does the RPS carve out proposed to be trued up in the RAC exhibit a trend?

[12] Note that calendar 2012 is trued up in 2014 through the 2013 PCAM (or PCAM and RPS carve out combo if the Company's proposal is accepted).

A. Yes, for the three years analyzed above, the Company's proposed RPS carve out is an undercollection in each year (see row F in Table 2 for the RPS carve out figures), with an average undercollection of $[redacted] million that would accrue interest and be amortized as a charge to customers in in the RAC (Schedule 122). Note that this figure is the average amount that would be netted out of the PCAM with the resulting figure being what would be subject to the deadband, sharing, and an earnings test.

Q. Does the earnings test appear to play a pivotal role in the difference between what would be refunded/charged to customers under the Company's proposal relative to the current mechanism?

A. Yes, the increased volatility in the amount to be charged/refunded from NVPC under PGE's proposal appears to be driven largely by the interaction between the RPS carve out and the earnings test.[13] This relationship is still being investigated by Staff.

Q. Are three years of results adequate to draw definitive conclusions about the expected results of the RPS carve out were it to be adopted?

A. While three years of data is useful in showing trends, all else equal additional years of results would be preferred. However, seeing that much of the RPS qualifying resource capacity in PGE's portfolio has come online in recent years, going back further in time provides results that are not as meaningful since they tend to underestimate the RPS attributed variance that would be carved out.

[13] Note in Table 2 that in 2011 the earnings test dictated that the Company only needed to refund $[redacted] million, but had the RPS carve out been in place it would have dictated that the Company would need to refund $[redacted] million. The difference between the $[redacted] and $[redacted] million is much greater than the RPS carve out (which would have been $[redacted] million) that would have been netted out of the PCAM for 2011.

This is simply because there was not as much RPS resource capacity online and generating energy for PGE customers. For example the Biglow Canyon wind farm, which is the Company's largest RPS resource in both capacity and energy terms and the main contributor to RPS resource variance, became fully operational in 2011. Therefore, the results from 2011, 2012, and 2013 are the best sample years indicative of what could happen if the RPS carve out proposal were to be adopted.

Q. How would additional RPS resources coming online as the RPS target increases impact customers through the proposed RPS carve out?

A. When additional RPS qualifying resources come online, such as the under construction Tucannon River wind farm expected to become operational at the end of 2014 or beginning of 2015, the RPS carve out will grow larger and the volatility of the variances to be trued up will increase further. Table 3 provides an indication of the magnitude of this increase:[14]

Table 3	
RPS Carve Out Current Resources (avg 2011-2013)	$ [redacted]
RPS Carve Out w/ Tucannon (2015-2019)	$
RPS Carve Out 2020-2024	$
RPS Carve Out after 2025	$

Note that Table 3 corresponds with the increasing standard of the RPS, which increases from the current 5% of retail load to 15% in 2015 (Tucannon is being built so that PGE can comply with this 15% standard), 20% in 2020 and 25% in 2025 onwards. When Tucannon comes online in 2015 it is expected that the

[14] The assumptions and calculations for the table above can be found in Exhibit Staff/1104. The data used for the calculations can be found in Attachment-A of the response to OPUC DR No. 475. The response to OPUC DR No. 475 can be found along with other data responses from the Company in Exhibit Staff/1103.

RPS carve out to be trued up in the RAC as proposed by PGE would increase by roughly 50% to $[redacted] million from the 2011-2013 average of $[redacted] million. If the RPS related NVPC variance remains the same as the average from 2011-2013 on a per MWh of energy basis the RPS carve out as proposed by PGE would be expected to increase to $[redacted] million in 2020 and $[redacted] million in 2020 as resources are added to comply with the RPS.[15]

Q. Is PGE's proposed calculation methodology the best way to carve out RPS related NVPC variance?

A. No. The Company's methodology works correctly in a number of situations, but does not work correctly in many others. While a perfect methodology is not possible, the Company's methodology suffers from a number of substantial flaws and better methods are available and should be considered.

Q. What are the major flaws of PGE's proposed RPS carve out calculation methodology?

A. The substantial flaws, which will be addressed in turn below, are:

1. The way the Company's proposal is adjusting the PCAM to accommodate the RPS carve out leads to questionable outcomes.
2. The methodology "carves out" more than RPS resource variance because it calculates the variance in power *value* rather than variance in power *costs* and includes market price variance in the calculation.

[15] Note this is likely a conservative estimate as it assumes (1) no load growth, (2) wholesale power prices remain at their 2011-2013 levels, and (3) RPS carve out variance per MWh of RPS qualifying energy remains the same as the average from 2011 to 2013, which includes a presumed proportionally larger share of variance-muting hydro power

3. The methodology does not account for the fact that PGE is able to generate power cheaper than it can purchase it on the wholesale power market to replace mis-forecast RPS resource generation in some situations.
4. The spot index used to report actual Mid-C market prices is not a good measure of the actual price of wholesale power transacted by PGE on the day ahead, hour ahead, balance day and real time markets.
5. The methodology is not theoretically consistent between Company-owned and Company-contracted resources
6. The methodology might provide an incentive for PGE to utilize its fuel price forecasts, market price forecast, renewable resource generation forecasts and renewable resource scheduling to collect more from customers through the RPS carve out.

Proposals to remove or mitigate these flaws will be presented along with the alternate calculation methodology proposals in Issue 4.

Q. Does the Company's proposed interaction between total NVPC variance (i.e. the PCAM) and the RPS carve out lead to questionable outcomes?

A. Yes. Staff does not believe PGE's proposed PCAM-RPS Carve out interaction is appropriate. It may be necessary to revisit the PCAM mechanism if an RPS carve out mechanism were to be adopted.

Q. Why is PGE's proposed interaction between total NVPC variance and the RPS carve out problematic?

A. In PGE's proposed RPS carve out, if total forecasted power costs were exactly equal to actual power costs there could still be (and likely would be) a NVPC true up in the RAC. This RPS carve out figure would then impact the PCAM true up as well[16] since the RPS carve out to be trued up in the RAC would be netted out of the PCAM. The resulting figure in the PCAM would then be subject to the deadband, sharing, and the earning test.

For example, if forecasted power costs, NVPC revenues collected and actual power costs were all exactly $500 million and the RPS carve out as proposed by PGE was calculated as a $15 million undercollection to be charged in the RAC, this $15 million would also be netted out of total NVPC in the PCAM, meaning that the PCAM would show a $15 million overcollection to be refunded to customers. This updated PCAM "overcollection" would fall within the deadband so that no true up would be necessary in the PCAM schedule. Therefore, even though expected power costs and actual power costs were equal (i.e. there was no NVPC variance), customers would be subject to a $15 million charge in the form of a NVPC variance true up in the RAC. If no pie exists, it is difficult to comprehend how a large piece could be "carved out" of that pie.

Q. What does PGE's methodology calculate?

A. As PGE recognizes, the Company's methodology (RPS generation * market price) is calculating the *value* of the power generated by the RPS resource,[17] with the difference between the value of the forecasted power (forecasted

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[16] Note that while the Company asserts that it is not proposing modifications to the structure of the PCAM in Exhibit PGE/500 Niman-Peschka-Hager/47, this is not an accurate depiction as is shown by Table2. The RPS carve out is netted out of the PCAM in a way that results in significant adjustments to the amounts trued up in the PCAM.

[17] The attachments in the Company's response to OPUC DR No. 471 label the variance as "power value" variance. The Company's response to OPUC DR No. 471 can be found in Exhibit Staff/1103

generation * forecasted market price) and the actual value of the power generated (actual generation * actual market price) being called the RPS variance. While decisions should be made based upon the value of power (i.e. the opportunity cost) and operating constraints, estimated value can be quite different than costs. NVPC is net variable power *costs* for a reason since actual costs are what are- and should be- collected from customers.

Q. Why is value not the correct measure for NVPC and NVPC variance?

A. For owned resources the value of power (i.e. market price) is the upper bound for the variable costs of power for customers and may not always represent how much is being spent by PGE on variable power costs.

For example, if the price of natural gas results in the marginal cost of generation for a Company owned gas fired power plant being less than the market price for power, the Company should run the plant and incur costs equal to its fuel costs rather than purchase power on the market since the market price is more expensive.

For instance, if heat rate adjusted fuel costs for a gas generator are equal to $30/ MWh and the market price of power is $50/ MWh, the Company (i.e. customers) incurs *costs* of $30/ MWh in NVPC even though generation from the plant has a *value* of $50/ MWh since this is the price the Company could sell the power generated by the plant in the wholesale market.

Customers paid to construct the gas plant (and have higher base rates as a result) in order to have the option to generate power at a cheaper variable cost than the market can provide and are rightfully charged the variable generation costs for power from the plant in NVPC instead of the market price- or value- of power.

Company owned renewable resources are an even more extreme case of this phenomenon as the capital expenditures to build them and bring them online are high, but the variable costs of operating the resource are essentially zero. In fact, as mentioned before, the variable cost for the generation from owned RPS resources is $0/MWh in the MONET model. Actually, even though the Tucannon wind farm under review in this case will presumably increase base rates as its construction costs are amortized, it is also expected to *decrease* NVPC by an expected $[redacted] million in 2015 according to the Company's initial estimates.

To take a further look at the difference between value and costs let us revive the single wind farm portfolio example from Issue 1 above:

Table 4:	A	B	C	D	E	F	G	H
	Load (MWh)	Wind Farm Generation (MWh)	Purchases/ Sales (MWh) (A-B)	Market Price ($/MWh)	NVPC ($) (C*D)	Wind Farm Power Costs ($)	Wind Farm Power Value ($) (B*D)	Total Power Value ($) (A*D)
Forecast	100	80	20	$30	$600	$0	$2,400	$3,000
Actual	100	50	50	$40	$2,000	$0	$2,000	$4,000
	NVPC (Power Cost) Variance				-$1,400	Power Value Variance		-$1,000

Note that in this example if power value is what was put into rates, then rates would be much higher as the forecasted power *costs* are $600 (column E forecast) while the forecasted power *value* is $3,000 (column H forecast) for the same amount of energy. Furthermore, note that the Company actually incurs costs of $2,000 (column E actual) in this example, $1,400 (column E variance) of which would have to be trued up. However, if customers were paying for power value they would incorrectly be overcharged and pay $4,000 (column H actual), $1,000 of which would need to be to be trued up (column H variance). For owned resources power value should always be at least as high as variable power costs.[18] Furthermore, power costs are what are actually expensed and paid for. As such, depending on interpretation of the RPS statute, it may be appropriate to carve out and true up RPS resource *NVPC variance*, but it is not appropriate to true up the RPS resource *value variance* as proposed by the Company.

Q. Does PGE's proposed calculation methodology incorrectly "carve out" some market price variance and assign it as RPS resource variance?

A. Yes. While this concern is inseparable from the value vs. cost concern just discussed, PGE's calculation methodology also includes variance from market prices and conflates this with the RPS resource intermittency variance intended to be carved out. The simplest way to show how mis-forecasting market prices (i.e. market price variance) leads to NVPC variance being incorrectly carved out with the Company's proposed methodology is to take a look at an hour where the Company correctly forecasts RPS resource generation but does not correctly forecast power prices. The single wind farm portfolio example is used again to analyze this sample hour in Table 5 below:

[18] Theoretically power value is always greater than or equal to variable power costs on a per unit basis, though there are some operational situations where an "out of the money" generator may produce power for short periods of time.

Table 5:	A	B	C	D	E
	Load (MWh)	Wind Farm Generation (MWh)	Purchases/ Sales (MWh) (A-B)	Market Price ($/MWh)	NVPC ($) (C*D)
Forecast	100	80	20	$40	$800
Actual	100	80	20	$30	$600
	NVPC (Power Cost) Variance				$200

Since the generation from the wind farm was correctly forecasted it is pretty straightforward that none of the variance should be carved out and attributed to the RPS and that all of the total variance in NVPC should be assigned to market price variance.[19] However, using the Company's methodology for an owned RPS resource $800 ([$80*40] – [$80*30] = $800) is "carved out" and assigned as RPS attributed variance for the hour. In this case, even though the *total* hourly variance in NVPC is only $200, PGE's methodology assigns $800 to the RPS carve out when it should assign $0. Thus, it is clear that the Company's methodology is not carving out only RPS resource variance since it includes market price variance which is not attributable to the RPS.

Q. Does PGE's methodology assume that if an RPS resource's generation is under-forecasted and energy is needed to make up the shortfall that this difference is purchased on the market?

A. Yes

Q. Is this assumption always correct?

A. While this assumption is correct in many situations, it is not always true. Natural gas price variance, coal price variance, market price variance, and access to

[19] Seeing as load was also forecasted correctly

market can all impact the dispatch decision (i.e. thermal plant optionality) of the Company's dispatchable generators. This is to say that when the Company forecasts a thermal generator to be "out of the money" (marginal generation costs > market price) but the generator is actually "in the money" (marginal generation costs < market price) when the hour comes around that the plant ends up generating energy it was not forecasted to generate. In this case the extra energy that is needed to pick up the slack from the over-forecasted renewable generation can be generated by the Company's own dispatchable resources at a cost that is less than the market price (hence the plant being in the money).[20]

Q. Does PGE plan to use the correct source for the "actual" market prices?

A. No. The Company plans to use the hourly Powerdex index for Mid-C[21] for the market price actuals in the RPS carve out. While this index is based upon prices for settled transactions on the real-time, hour-ahead, day-ahead and balance-day market and is the index used to settle Bonneville Power Administration (BPA) generation imbalances, it does not represent a good price indicator for PGE settled transactions for calendar 2013. Using the hourly volume weighted price of power from actual power transactions made by PGE in 2013 and calculating the variance between this price and the hourly Powerdex index price one finds that on average the index price is $[redacted]/MWh

[20] Note that "in the money" thermal capacity set aside to integrate wind within the hour may also complicate the Company's assumption

[21] See the response to OPUC DR No. found in Exhibit/Staff 1103.

[redacted] than the Company's actual hourly transacted prices.[22] While this phenomenon may be isolated to 2013, it may not be, and the difference in 2013 is very significant. Calculating the volume weighted price of actual transactions is simple enough that the actual price for PGE transactions ought to be used rather than the index.[23] The best source for the price of PGE power market transactions is actual PGE power market transactions.

Q. Is the Company's calculation methodology theoretically consistent for its owned and contracted RPS resources?

A. No. PGE's proposal correctly uses the difference in price between the contract and the market price for contracted resource variance. However, the Company uses monthly on-peak and off-peak prices for the market price figure rather than hourly prices like it does for its owned resources. While this makes sense on the surface if a contracted resources' contract is based upon monthly on-peak and off-peak prices, it is theoretically inconsistent with the hourly methodology for the Company's owned resources. When thinking about the Company's owned RPS resources, the theoretical equivalent of the contract price for a contracted resource is the variable cost of the owned resource: zero. This does not change across hours and the Company's proposal does not move away from hourly market prices to monthly averages in this case. All

[22] This data was provided by the Company in Attachment 468-A in response to OPUC DR No. 468 which can be found in Exhibit/Staff 1103. Only transactions that were made for delivery within one month of the transaction date are included in this data. Note that almost all of the transactions were made within 1 day of scheduled delivery. Both market purchases and market sales are considered as positive values for the calculation.

[23] Note all of Staff's proposed methodologies in Issue 4 use the volume weighted hourly average price of PGE transactions made for the hour in question within one week of that hour as the actual market price.

resources should be treated consistently and either be carved out hourly or monthly.

Q. Does the 100% pass through proposed in the RPS carve out present incentive for PGE to utilize the NVPC mechanism to overcollect from customers?

A. While Staff is not asserting that it *expects* PGE would utilize the NVPC mechanism to collect more from customers, there would be incentives available for the Company to exploit. Specifically, it would be possible for the Company to use its RPS resource generation forecasts, RPS resource scheduling, fuel price forecasts, and market price forecasts to direct money into buckets that would allow the Company to collect additional revenue from customers in rates. If an RPS carve out proposal were to be put in place additional emphasis would need to be placed on reviewing these inputs in the AUT.

Q. Does Staff agree with the proposed calculation methodology as it applies to integration costs, royalty costs, and PTC's?

A. Yes. Staff feels that the methodology proposed by the Company is correct. However, Exhibit PGE/503, Niman-Peschka-Hager/1 is not sufficiently clear about what is being calculated, though the workpapers in Attachment-A of the Company's response to OPUC DR No. 471 provide the needed detail. Staff will document this detail in its alternate proposed methodologies in Issue 4.

<u>Issue 4: Alternate RPS Carve Out Calculation Methodologies</u>

Q. Are there calculation methodologies that improve upon the Company's proposal?

A. While a perfect methodology to carve out RPS attributed variance is not possible, there are methodologies that improve upon PGE's proposed methodology in concrete ways by removing or muting the flaws noted in Issue 3 above.

Q. How many alternate methodologies is Staff putting forth?

A. Staff is putting forth four methodologies that improve upon PGE's proposal for consideration should the Commission decide to adopt an RPS carve out for trueing up RPS related NVPC variance in the RAC. The first alternative presented below is Staff's preferred carve out methodology.

Q. Please summarize Staff's preferred calculation methodology, <u>Proposed Methodology #1</u>, and explain its core differences with PGE's proposed methodology.

A. An overview summary of Staff's preferred RPS carve out calculation methodology from a conceptual framework is as follows:

$$\boldsymbol{RPS\ resource\ NVPC\ variance} = \boldsymbol{(Forecasted\ generation - Actual\ generation) * Market\ Price}$$

Where owned resources have an additional adjustment for integration costs, royalty costs, and PTCs and contracted resources' costs are netted against the contracted price of energy. Furthermore, the market price will be the forecasted price if forecasted generation is less than actual generation and the actual price if forecasted generation is greater than actual generation.

This methodology differs substantially from the Company's proposal. Among other things it is an estimate of the variance between actual and forecasted *costs* to obtain an amount of RPS electricity as opposed to an estimate of the variance between the actual and forecasted *value* of RPS electricity.

Q. How does Staff's preferred methodology estimate *cost* variance rather than *value* variance and remove market price variance from the carve out?

A. Staff's preferred methodology was constructed using the basic theoretical construct of finding the variance in costs to obtain an equivalent amount of energy from an RPS resource between the forecast in the AUT and the actual costs incurred. Here it is important to note again that in its most basic form NVPC variance = actual NVPC – forecasted NVPC. Table 6 was constructed to illustrate this concept:

Table 6: Owned RPS Resources

	A	B	C	D	E	F	G
Hour	forecasted Generation (MWh)	Actual Generation (MWh)	Forecasted Market Price ($/MWh)	Actual Market Price ($/MWh)	Forecasted Costs for 20 MWh ($)	Actual Costs for 20 MWh ($)	Cost Variance for 20 MWh ($)
1	20	10	$ 50	$ 40	$ -	$ 400	$ 400
2	10	20	$ 50	$ 40	$ 500	$ -	$ (500)

First, look at hour 1. In this case the Company projected an owned RPS resource would generate 20 MWh of electricity. Since the RPS resource is modeled as having zero variable costs, this 20 MWh of electricity has a total forecasted cost of $0 (20 MWh * $0/MWh). To find the variance in costs for this amount of electricity it is necessary to find the *actual* costs of this 20 MWh of electricity. Since in hour 1 the RPS resource only ended up generating 10 MWh instead of the 20 MWh that was forecasted, the Company needed to buy 10 MWh of power on the market to make up the difference and provide 20 MWh to its customers (10 MWh from the RPS resource and 10 MWh from market). Furthermore, the cost of this 10 MWh of purchased power is the price paid for it by PGE on the market, (i.e. the actual market price, which in this example is $40/MWh).[24] Therefore, the Company ended up paying $400 (10 MWh * $0/MWh for the RPS generation + 10 MWh * $40/MWh for the shortfall needed to be purchased on the market = $400) for the 20 MWh rather than the $0 it forecasted it would pay. This $400 is the variance.

Hour 2 uses the same concept. However, for this hour the RPS resource was forecasted to generate 10 MWh but ended up generating 20 MWh in reality. In this case, the *forecasted* cost of the equivalent 20 MWh is $500[25] because only 10 MWh was forecasted to come from the zero variable cost RPS resource while the other 10 MWh were forecasted to be purchased on the market at the forecasted price of $50/MWh. In reality, the RPS resource generated the entire 20 MWh at a total variable cost of $0, making the variance ($500).

[24] Note this assumes that changing conditions (market price and thermal plant fuel prices) from the forecast did not lead to a change in dispatch where more power was generated for the hour from the Company's own thermal resources. In this case the additional 10 MWh needed to serve customers could be priced at the marginal generation cost of the thermal resource that generated more energy in reality than was forecast. Pricing the power to replace the mis-forecast wind generation this way is done in Proposed Methodology #2.

[25] Note that PGE RPS resource generation < PGE load in each hour of the year so that it is certain that PGE will need the entire 20MWh to serve load in the forecast, whether the entire 20 MWh is projected to come from the RPS resource or not.

While the calculation is slightly more complex, the same concept can be used for the contracted RPS resources. For these resources, in general, the contracted price is higher than either the forecasted or actual market price so when the actual generation from the resource is greater than the forecasted generation, actual costs are higher than forecasted costs (the RPS carve out is positive).[26] Consequently, when forecasted generation is greater than actual generation, actual costs are less than forecasted costs and the variance is negative.

Q. Can you summarize Staff's general process to derive its preferred RPS carve out methodology?

A. Staff's general process for deriving the RPS carve out calculation methodology can be summed up by the steps followed to determine the variance in the previous question, which are:

1. Determine the amount of power in question by finding the higher number between the forecasted and actual generation of the RPS resource.
2. Determine a formula to estimate how much cost was attributed to this amount of energy in the AUT forecast.
3. Determine a formula to estimate how much this amount of energy cost in reality.
4. Find the formula that calculates RPS resource NVPC variance by subtracting (2) from (3).

Q. What is Staff's preferred RPS carve out methodology?

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[26] Which is the opposite for Company owned resources

A. Staff's preferred methodology applies the process from the previous question to derive the calculation methodology found in Table 7 below:

Table 7: Proposed Methodology #1	
Calculated Hourly	
Resource Type	**Calculation**
Owned Wind Resources	*If Forecasted Generation > Scheduled Generation:* [Forecasted Generation - Scheduled Generation] * Actual Market Price *If Forecasted Generation < Scheduled Generation:* [Forecasted Generation - Scheduled Generation] * Forecasted Market Price
RPS Hydro Resources	*If Forecasted Generation > Actual Generation:* ([Forecasted Generation - Actual Generation]*Renewable Factor) * Actual Market Price *If Forecasted Generation < Actual Generation:* ([Forecasted Generation - Actual Generation]*Renewable Factor) * Forecasted Market Price
Contracted RPS Resources	*If Forecasted Generation > Actual Generation:* {([Forecasted Generation - Actual Generation] * Actual Market Price) + [Actual Generation * Contract Price]} - [Forecasted Generation * Contract Price] *If Forecasted Generation < Actual Generation:* [Actual Generation * Contract Price] - {[Forecasted Generation * Contract Price] + ([Actual Generation - Forecasted Generation] * Forecasted Market Price)}
Calculated Monthly	
Integration Costs	Actual fixed BPA integration costs - Forecasted fixed BPA integration costs
Royalty Costs	Actual Royalty Payments - Forecasted Royalty Payments
Calculated Yearly	
PTCs	[Actual Generation - Forecasted Generation]* PTC Rate

Actual market price = Volume weighted price of PGE's power transactions (including both purchases and sales considered as positive values) for delivery for that hour made within 1 week of the hour of delivery
Renewable Factor = [Low Impact Hydro MW + Upgrade MW]/[Plant Capacity MW]

Q. Which of the flaws with PGE's proposal does <u>Proposed Methodology #1</u> fix or improve and what are its advantages?

A. This methodology makes the following improvements:

- It removes market price variance from the calculation to better "carve out" RPS related NVPC variance
- It mostly removes the power *value* variance problem and calculates actual costs

- It uses actual PGE power transactions for the actual market price
- It is theoretically consistent between owned and contracted resources
- It removes much of the possibility for utilizing the RPS carve out to collect more from customers
- It is simple

Q. What are the flaws of Proposed Methodology #1?

A. This methodology has the following shortcomings:

- It does not alter the PCAM mechanism to account for the RPS carve out
- It does not fix or mute the thermal resource optionality problem

Q. Please summarize Staff's Proposed Methodology #2, and explain its core differences from PGE's proposed methodology and Proposed Methodology #1.

A. Staff's second proposed methodology is derived using the same concept as the preferred methodology (Proposed Methodology #1), but the generation variance of the RPS resource is not assumed to come from the market in all situations. Proposed Methodology #2 solves the same problems as the preferred methodology and largely solves the plant dispatch/optionality issue that the preferred methodology does not, though this comes at the cost of the mechanism being much more complex.

Q. How does Proposed Methodology #2 largely solve the plant dispatch issue present in PGE's proposed methodology and Proposed Methodology #1?

A. Proposed Methodology #2 does not assume that the energy needed to replace RPS resource generation when the forecasted generation is greater than actual generation always comes from market purchases. Proposed Methodology #2 finds hours where one of PGE's thermal plants generated more energy in reality than was forecasted (i.e. the plant dispatch changed) and assumes the energy to replace the under-forecasted RPS generation came from PGE's thermal resources by pricing this energy at the marginal generation cost of the thermal resource rather than the market price as in Proposed Methodology #1.

Q. What is Proposed Methodology #2?

A. Proposed Methodology #2 is found in Table 8 below.

Table 8: Proposed Methodology #2
For each hour:
If no thermal resource's actual generation is 20 MWh greater than its forecasted generation then use Proposed Methodology #1
If one of more thermal resource's actual generation is 20 MWh greater than its forecasted generation use the following:
1. For each thermal resource (i) with 20 MWh or more actual generation than forecasted generation calculate the variance:
$Thermal\ Resource\ Variance_i = Actual\ Generation_i - Forecasted\ Generation_i$
2. Sum the variances across thermal resources in (1):
$Total\ Thermal\ Variance = \sum_i Thermal\ Resource\ Variance_i$
3. Calculate the weighted average marginal cost of generation (WAMC) of the Total Thermal Variance in (2):
$WAMC = \sum_i \frac{Thermal\ Resource\ Variance_i}{Total\ Thermal\ Variance} * (heat\ rate_i * fuel\ cost_i)$
4. Distribute the Total Thermal Variance in (2) across the Company's RPS qualifying resources in the following order: (i) owned wind resources, (ii) RPS hydro resources, (iii) contracted RPS resources. Use the following distribution method:
(a) If owned wind resource generation variance is greater than Total Thermal Variance:
*Owned Wind Carve Out = [Total Thermal Variance * WAMC] + ([Owned Wind Variance - Total Thermal Variance] * Market Price)*
RPS Hydro Resources and Contracted RPS Resources carve out: follow Proposed Methodology #1
(b) If owned wind resource generation variance is less the Total Thermal Variance, but owned wind resource generation variance + RPS hydro resource generation variance is greater than Total Thermal Variance:
*Owned Wind Carve Out = [Owned Wind Variance * WAMC]*
*RPS Hydro Carve Out = ([Total Thermal Variance - Owned Wind Variance] * WAMC) + ([RPS Hydro Variance - Owned Wind Variance - Total Thermal Variance] * Market Price)*
Contracted RPS carve out: follow Proposed Methodology #1
(c) If owned wind resource generation variance + RPS hydro resource generation is less than Total Thermal Variance but owned wind resource generation variance + RPS hydro generation variance + conctracted RPS generation variance is greater than Total Thermal Variance:
*Owned Wind Carve Out = [Owned Wind Variance * WAMC]*
*RPS Hydro Carve Out = [RPS Hydro Variance * WAMC]*
Contracted Resources: follow Proposed Methodology #1, but replace Market Price with WAMC
(d) If Total Thermal Variance > Total RPS resource variance
All Resources: follow Proposed Methodology #1, but replace Market Price with WAMC

Q. Please summarize Staff's Proposed Methodology #3 and explain its core differences with PGE's proposed methodology and Staff's other proposed methodologies.

A. Proposed Methodology #3 (as well as Proposed Methodology #4) utilizes PGE's MONET model that is used to forecast and set rates in the AUT. MONET uses and in some instances generates forecasts for the necessary inputs to project NVPC. The last MONET run of the AUT process in November of each year is used to set rates for the upcoming calendar year. This model run includes the forecasts of RPS resource generation, market prices, and fuel prices necessary to calculate the RPS carve out under PGE and Staff's proposed RPS carve out calculation methodologies. MONET dispatches the resources in PGE's portfolio based upon these forecasts. Since MONET dispatches resources, it is a useful tool for solving the thermal plant optionality (or plant dispatch) issue. Furthermore, it utilizes a tool already used by PGE to estimate NVPC.

Q. What are the advantages and disadvantages of Proposed Methodology #3?

A. A similar methodology was proposed in a stipulation between PGE and Staff for the Hydro-only PCAM considered in UE 165. A description of the advantages and disadvantages of using MONET in this manner can be found in Exhibit UE 165/Staff/300, Galbraith/4-8.

Table 9: Proposed Methodology #3	
1. Take the last run from MONET from the AUT for the calendar year in question	
2. Re-run MONET with the same inputs except replace the forecasts with actuals for the following:	
	a. RPS resource generation by resource
	b. Market Prices
	c. Natural Gas Prices
3. Calculate the RPS carve out by subtracting (1) from (2)	

Q. What is Proposed Methodology #4?

A. Proposed Methodology #4 is very similar to Proposed Methodology #3 except that the only input changed from forecasted values to actual values for the re-run of MONET is resource specific RPS resource generation. This methodology further isolates RPS resource intermittency from market and natural gas price changes, though it may result in no re-dispatching of PGE's thermal resources given that market and natural gas prices do not change from the original run in the AUT. Proposed Methodology #4 is found in Table 10:

Table 10: Proposed Methodology #4
1. Take the last run from MONET from the AUT for the
2. Re-run MONET with the same inputs except replace the forecasted generation with actual generation for each RPS resource
3. Calculate the RPS carve out by subtracting (1) from (2)

Q. Please summarize the advantages and disadvantages of PGE's proposal and Staff's alternative proposals.

A. Table 11 below shows the summary:

Table 11:	RPS Carve Out Calculation Methodology				
	PGE's Proposal	Staff PM #1	Staff PM #2	Staff PM #3	Staff PM #4
Removes need to review PCAM mechanism					
Simple to Calculate	√	√			
Isolates RPS variance from market price variance		√	√		√
Accounts for plant dispatch			√	√	√
Calculates cost rather than value		√	√	√	√
Theoretically consistent between owned and contracted resources		√	√	√	√
Uses acutal market price measure		√	√	√	
Reduces incentive to overcollect		√	√		
Utilizes existing models				√	√

Q. What other matter would you like to address?

A. Staff anticipates that other parties in this docket will file testimony on PGE's proposed RPS carve out. Staff reserves the opportunity to respond in its next round of testimony.

Q. Does this conclude your direct testimony?

A. Yes.

CASE: UE 283
WITNESS: RYAN BRACKEN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1101

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME:	RYAN BRACKEN
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR ECONOMIST, ENERGY RESOURCES AND PLANNING
ADDRESS:	3930 FAIRVIEW INDUSTRIAL DR. SE SALEM, OREGON 97302
EDUCATION:	PhD Candidate, Energy Economics, Colorado School of Mines MA, Economics, Colorado State University BA, Economics, University of Hawaii at Hilo
EXPERIENCE:	I received a Bachelor of Arts Degree in Economics from the University of Hawaii at Hilo. I also received a Masters of Arts Degree in Economics from Colorado State University with research focusing on commodity markets. I am currently a PhD candidate in Energy Economics at the Colorado School of Mines finishing my dissertation research relating to electric power generation. I recently finished a fellowship for the federal government researching power generation options in China. My research has been focused primarily on electric generation and commodity markets. I have taught numerous introductory and intermediate economics courses at both the Colorado School of Mines and Tsinghua University in Beijing. I have worked as a senior economist for the Oregon Public Utility Commission for one year. Previously I was a market consultant in the telecommunications industry in China.

CASE: UE 283
WITNESS: RYAN BRACKEN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1102

Exhibits in Support Of Opening Testimony

June 11, 2014

The House Committee on Energy and the Environment heard public testimony on SB 838 on April 18, 2007.

A representative of ICNU testified that he thought the reference in 13a to subsection 13(1) in the A-Engrossed version of SB 838 was a mistake, and that the correct reference is to subsection 13(3).

> [Mark Nelson/ICNU:] I'm not sure if this was a mistake, but originally our understanding was the only thing that was going to be included in the automatic adjustment clause were those costs prudently incurred that you find on lines 24 to 27 to construct or otherwise acquire facilities that generate electricity and, or, for associated electricity transmission. That was our understanding of what would go into an automatic adjustment clause.
>
> But what I believe, I hope, is a typographical error all the costs that are in lines 16-21 including interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis. We believe that that also is going to be included by error under [an] automatic adjustment clause.
>
> The error is in line 36 with a reference to 13(1). We believe that should be a reference to 13(3) tying back to the capital cost not all costs related to renewables. That was our understanding of what the agreement was. If I'm wrong, then we need to know that. But, to add all those other costs to an automatic adjustment clause without an evidentiary process, hearing, just turns the whole PUC process, we believe, on its head.[1]

Testimony from the PacifiCorp witness:

> [Representative Burley to witnesses for PacifiCorp:] I think you heard the conversation earlier about 13(1) and (3) and then Section 13a and the question there, but before we get into that, what I'm curious about is, with the automatic adjustment clause, is it your understanding that you would be able to recover the cost not only of the renewable resource itself or the facility that produces the renewable energy, but also whatever you need as far as integrating, firming or shaping?
>
> [Brent Gale/PacifiCorp:] Madame Chair, Rep. Burley, what we're allowed to recover under the automatic adjustment clause, as I view it, are the capital costs of the renewables that we own as well as any power purchases that might be necessary for the shaping or the firming. Currently we already have adjustment clauses that will recover the power purchase cost if we were to purchase the power of renewables from a third party. That particular clause also recovers the

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[1] Testimony to the House Energy and Environment Committee, April 18, 2007, Time 34:10 – 35:56.

variable costs of the facilities that we own. What the clause does not recover are the fixed, or the capital costs, of the facilities that we own. And we choose to own facilities when it is the least cost for our customers. As a result, the current situation that we have in the statute, or in the rules rather, provides a disincentive, for the utility to own renewables even when that is the least cost option for the customers. What the automatic adjustment clause provision attempts to do in section 13(3) is to simply say that in addition to being able to pass through the benefits of the renewables through an automatic adjustment clause the utility will have the opportunity to match those benefits with the costs and recover the costs through an adjustment mechanism. The alternative is not to pass the benefits through and wait until a rate case to do so. But, when we own the renewable, the renewable kilowatt hours have a zero variable cost. As a result, customers in Oregon receive free energy, essentially, through the adjustment mechanism. For every 100 MW of renewables that PacifiCorp owns, the benefit to Oregon customers is about $4 million of that free energy. What we're simply asking is that there be a matching. We can't give away free energy just as the industrial customers don't give away free product. Customers have to pay for those benefits. We're asking that we be allowed to recover those costs and that's what section 13(3) does.

[Rep. Burley:] I'm still not quite clear on this Brent, because you mentioned the power purchase for shaping and firming. But I would suspect that some point you are going to be at the point when you no longer have that firm baseload to shape and firm and there may not be any power purchase to shape and firm and you are going to have to go out and do some construction of some sort in order to have that base to back it up. Would you be able to pass those costs along through the automatic adjustment clause?

[Brent Gale/PacifiCorp:] Madam Chair, Honorable Rep. Burley, I do not believe that those costs of say adding a gas plant were intended to be recovered under section 13a or section 13(3).

Section 13(3) clearly does not contemplate that. Section 13(1) has a reference to the shaping of the. . . if you look at Section13a, and that went through several iterations by the way. 13a is really just a timing provision. And, what 13a was intended to do was to say to the commission that you have to adopt these rules that establish the adjustment mechanism by a given date. And as this process went on certain language got added to section 13a including the reference to section 13(1). The intent however though, because that is a section that gives the commission a timeline, it's only going to apply to those costs that the commission considers at the time it adopts the rate. I do not see that a gas generating plant that will be added in the future could be included in that clause through the reference to section 13(1). Is that helpful?

It could have been clearer if it had said 13(3). Do I think it is material or is there a need for a material change to change section 13a to refer to section 13(3) as Mr.

Early indicated? No. I don't believe it's necessary. I believe the statute can be interpreted, or the bill can be interpreted, correctly without that change.

[Rep. Burley:] But, if we changed it, just to be clear, would that be a problem?

[Brent Gale/PacifiCorp:] If the reference to section 13(1) in Section 13a was changed, and that's the only change in 13a, to section 13(3) that probably doesn't have a material impact on our ability to support the bill. I can't speak for anybody else.[2]

Written testimony submitted by the Citizens' Utility Board to the House Committee on Energy and the Environment Committee on April 18, 2007, supports ICNU's interpretation of sections 13 and 13a. Notably, CUB testifies that there is already a mechanism in place that allows utilities to recover variable costs associated with the resources and that the automatic adjustment mechanism in the bill is intended to allow recovery of "fixed costs of the resource":

> [Re: Cost Recovery (Section 13):] This is a new provision that directs the PUC to identify a mechanism whereby the utility can apply for and get timely recovery of prudently incurred investment in renewable resources without the need for a rate case. This makes policy sense, because the RES will promote a strategy of adding renewable resources on an on-going basis, and this might otherwise require annual rate cases, which are resource intensive proceedings. In addition, as a renewable resource comes on line, the utility's variable costs, or costs of fuel, go down and those savings will be passed on to the customer through annual rate adjustment that are currently in place. It is not warranted to allow cost reductions to flow through to the customers from this RES and to allow for reasonably contemporaneous recovery of the fixed costs of the resource. Further, the opportunity to recover fixed costs between rate cases currently exists at the PUC; this provision is to formalize the process in a more consistent way between utilities.[3]

At a subsequent work session on April 30, 2007, legislative counsel described a proposed amendment to SB 838 A-Engrossed that clarified that the reference in section 13a to costs described in subsection 13(1) was incorrect and that the correct reference is to costs described in subsection (3). The amendment was adopted by the Committee.

[Dave Hendryxx:] We also corrected a reference in section 13a. Used to refer to costs as required section under 13(1) and that was an incorrect reference. It's now been corrected to subsection 13(3) as far as which costs are being recovered underneath the automatic adjustment clause.[4]

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[2] Testimony to House Energy and Environment Committee, April 18, 2007, time: 1:24:30
[3] Written Testimony of Jason Eisdorfer presented to House Committee on Energy and the Environment, April 18, 2014.
[4] House Committee on Energy and the Environment, April 30, 2007 worksession, Time .

Similarly, testimony by Lee Sparling, PUC Utility Division Administrator, at the April 30 work session supports the conclusion the automatic adjustment clause had a limited applicability.

[Lee Sparling:] With respect to the A-63 amendments relative to the A-Engrossed Section 838 . . . The only difference here is that again we're talking about automatic adjustment clause, which means we'd be focusing on the costs that are outlined in the other provisions of SB 838, regarding the costs of the renewable resources and associated transmission. These proceedings would not go into other costs that the utility incurs for, say, back-up resources for these renewable resources, nor would this proceeding get into the companies' other costs for pensions and benefits, its cost of capital or any other category of costs. We will be limited to what's specified in the bill for consideration under the automatic adjustment clause.[5]

[5] House Committee on Energy and the Environment, April 30, 2007 Worksession, time:

CASE: UE 283
WITNESS: RYAN BRACKEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1103

Exhibits in Support
Of Opening Testimony

June 11, 2014

April 23, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 415
Dated April 9, 2014

Request:

Does PGE assume that all power to make up generation deficiencies from intermittent renewable resources for every hour of the year will come from the wholesale market even if PGE has additional available dispatch-able capacity as PGE/503 Page 1 suggests? Please explain in detail.

Response:

Yes. In order to keep the mechanism fairly simple, PGE assumed that whether the replacement energy comes from the market or a PGE resource, the value of that energy is the market price. In other words, if a PGE thermal resource generates an additional MWh to replace a MWh of wind, that thermal MWh is worth what it would otherwise sell for in the market.

April 23, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 416
Dated April 9, 2014

Request:

Refer to PGE/503 Page 1. Define in detail, both in words and in a mathematical equation, the "Integration Costs" portion of the "Biglow & Tucannon Power Cost" row of the RPS carve out calculation methodology. Include the time period the integration costs will be defined (i.e. hourly, yearly, etc.), the specific sources from which they will come, the methodology for forecasting them in the AUT, and the methodology for reporting the actuals.

Response:

PGE currently integrates wind through BPA. PGE's MONET model includes an estimate of these integration charges (see "#M610PUC10-056-2015 GRC.xlsm", tab "PwrCsOut" from PGE's April 1 net variable power cost filing). PGE's actual integration charges from BPA are expensed and can be tracked. See PGE's response to ICNU Data Request No. 079 for an example of the RPS Carve Out calculation using historical actuals, including integration costs.

Please see the Minimum Filing Requirement document "^_2015GRCBiglowBPAVERBS.docx" available at the following path: "\Vol 7 - Wind\Biglow\Integration\BPA VERBS" for a description of how BPA integration charges are modeled.

For simplicity, PGE is not proposing inclusion of imbalance premiums or day-ahead forecast error as part of the RPS Carve Out.

PGE is working toward the least-cost, least-risk option for integrating wind which could include self-integration or some mix of services from BPA and PGE. PGE welcomes the opportunity to discuss with OPUC Staff and other parties a reasonable methodology for inclusion of these integration costs in the RPS Carve Out.

For the time being, integration costs for purposes of the RPS Carve Out are BPA integration costs.

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April 23, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 421
Dated April 9, 2014

__Request:__

421-423. Please refer to Table 3 from page 46 of exhibit 500. In the "Variables for determining actuals" section of the table there is an item named "Hourly Market Prices." Correspondingly refer to PGE/503 Page 1 and the "Actual" column of the calculation methodology table. In this column the calculation method for PGE owned resources includes the item "Hourly Mid-C Price." Please confirm whether these are the same and answer the following questions:

Regarding the actual Mid-C price used for calculating the RPS carve out:

> **Assume that the Company buys 100MWh of power for a specific hour on the day ahead market for $40/MWh, and buys 100MWh of power for that same hour on the hour ahead market for $60/MWh. What is the "actual" Mid-C market price that will be used for the actuals of the RPS Carve-Out calculation for that hour? Additionally, provide a general mathematical representation for how the Company will report the actual Mid-C price when the Company makes market transactions for the same hour at different prices.**

__Response:__

In response to the preface to OPUC Data Request No. 421-423, the "Hourly Market Prices" and "Hourly Mid-C Price" referenced are the same.

In response to OPUC Data Request No. 421, PGE responds as follows:

The indicative Mid-C market price that PGE will use for purposes of calculating the RPS Carve Out would be based on the PowerDex hourly Mid-C index, which is a survey-based index supported by reporting of transaction by parties trading at that hub. This is the best available hourly market data and the Bonneville Power Administration likely settles generation imbalance charges using this index.

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April 23, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 424
Dated April 9, 2014

Request:

Assume that the forecasted and actual RPS resources generation match exactly. Assume that the market price projections differ from actual market prices. In this instance, would the PGE carve out proposal result in an adjustment?

Response:

Yes. The proposed RPS Carve Out accounts for both price and quantity variations.

April 23, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 426
Dated April 9, 2014

Request:

For both calendar 2011 and 2012, calculate the RPS Carve Out as proposed by the Company in PGE/500 pages 43-47 and PGE/503 page 1. Please provide the response on an hourly basis with a roll up to the yearly figure in an excel spreadsheet with formulae intact. At a minimum include all of the columns for each worksheet of the PGE/500 confidential workpapers excel file "#M610PUC10-00n-2015 GRC – HrlyDiagOnly" plus any columns necessary to include the integration costs and royalty costs for both the forecasted and actual figures

Response:

PGE objects to this request as overly broad and unduly burdensome. Notwithstanding this objection, PGE responds as follows:

Please refer to PGE's response to ICNU Data Request No. 079.

May 27, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 468
Dated May 13, 2014

Request:

For every wholesale power transaction (either sales or purchases) made by PGE for delivery within one month of the transaction date for calendar 2013, please provide the following in chronological order by time of delivery:

a. **Hour and date of delivery**
b. **Date of transaction**
c. **MWh of power transacted**
d. **Price of power transacted**

Response:

Attachment 468-A provides the requested information. Attachment 468-A is confidential and subject to Protective Order No. 14-043. Certain transactions in the attachment were settled at a market index rather than a negotiated fixed price. For each transaction, PGE has provided the settlement price. Financial transactions (not included) executed for the same delivery period in the forward markets may act as a hedge against some of the physical transactions executed at Index at the time of settlement, which could result in a variance between the settled price and actual value of a physical transaction.

UE 283

Attachment 468-A

Confidential and Subject to Protective Order No. 14-043

Provided in Electronic Format Only

2013 Power Transactions

May 27, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 471
Dated May 13, 2014

Request:

Please update ICNU Data Response No. 079 to include calendar years 2009 and 2010 in addition to calendar years 2011, 2012 and 2013.

Response:

Per discussion with OPUC Staff, PGE is providing 2011 and 2012 RPS Carve Out examples using all eligible renewable resources, and 2009 and 2010 using just the Biglow Canyon wind farm (Biglow).

Attachment 471-A contains the following RPS Carve Out examples using:

- 2011 forecast and actual data
- 2012 forecast and actual data
- 2013 forecast and actual data

For 2011 and 2012, PGE is using the forecast generation for 2015 as the baseline for Biglow, because it is based on the improved 5-year rolling average methodology. The 2013 example is a revised version to the example provided in PGE's Response to ICNU Data Request No. 079. For details on the revisions, please see PGE's Supplemental Response to ICNU Data Request No. 079.

For 2009 and 2010, PGE is providing an analysis using just the variance for PGE's Biglow, which represents the majority of PGE's renewables. Attachment 471-B provides the analyses for 2009, 2010 and revised versions of the 2011 and 2012 Biglow Only examples provided in PGE's Response to ICNU Data Request No. 079. For details on the revisions, please see PGE's Supplemental Response to ICNU Data Request No. 079.

The supporting data are included in the referenced files. Please note that in addition to MWh forecast variances, price variances played a significant role in the results for these two years.

Attachment 471-A and 471-B are confidential and subject to Protective Order No. 14-043.

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UE 283

Attachment 471-A

Confidential and Subject to Protective Order No. 14-043

Provided in Electronic Format Only

2011, 2012 and 2013 RPS Carve Out Examples

UE 283

Attachment 471-B

Confidential and Subject to Protective Order No. 14-043

Provided in Electronic Format Only

2009, 2010, 2011 and 2012 RPS Carve Out Examples
(Biglow Only)

May 27, 2014

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 283
PGE Response to OPUC Data Request No. 475
Dated May 13, 2014

Request:

Please provide the following for every year under the current net variable power cost mechanism:

a. **Power Cost Variance that was subject to deadband and sharing in the PCAM**
b. **RPS carve out variance if the RPS carve out as proposed by the Company had been in place for each year**
c. **NVPC Variance in the PCAM had the RPS carve out as proposed by the Company been in place for each year**
d. **Amount of the NVPC variance subject to sharing in the PCAM had the RPS carve out as proposed by the Company been in place for each year**

Response:

Per discussion with OPUC Staff, PGE has developed full RPS Carve Out examples for 2011, 2012 and 2013. Therefore, PGE provides the following responses on Power Cost Variance (PCV) for the years 2011 – 2013. Please note that the 2013 PCAM has not yet been filed, hence the 2013 example is preliminary and draft.

Attachment 475-A provides a summary of the PCAM and RPS PCV for 2011, 2012 and 2013.

Attachment 475-B provides details for the calculation of the PCV referenced in Attachment 475-A. Attachment 475-A and 475-B are confidential and subject to Protective Order No. 14-043.

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UE 283

Attachment 475-A

Confidential and Subject to Protective Order No. 14-043

Provided in Electronic Format Only

Summary of the PCAM and RPS PCV for 2011 - 2013

UE 283

Attachment 475-B

Confidential and Subject to Protective Order No. 14-043

Provided in Electronic Format Only

Details for the Calculation of the PCV

CASE: UE 283
WITNESS: RYAN BRACKEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1104

Exhibits in Support
Of Opening Testimony

REDACTED
June 11, 2014

This page is confidential.

You must have signed the Protective Order in this docket in order to view this page.

CASE: UE 283
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1200

Opening Testimony

June 11, 2014

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

A. My name is John Crider. My business address is 3930 Fairview Industrial Dr. SE, Salem, Oregon 97308-1088.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Staff Exhibit 1201.

Q. What is the purpose of your testimony?

A. To address the prudence of the Company's acquisition of 10 percent of the Boardman power plant ownership from Power Resources Cooperative (PRC)

Q. Did you prepare an exhibit for this docket other than your qualification statement?

A. No.

Discussion

Q. Please summarize the agreement under review.

A. The Company is the majority owner of the Boardman coal generation plant with an eighty percent share. The Company has negotiated the purchase of an additional ten percent share of the plant from the current share owner, PRC. For an agreed upon cash amount, PGE will assume ownership and responsibilities related to the plant from PRC.

Q. Please summarize the terms of the agreement with PRC.

A. The agreement has five components:

- PRC's "Boardman purchase payment" to PGE in exchange for PGE assuming all PRC's obligations relating to Boardman;
- PGE's purchase of PRC's equipment and fuel inventory;
- Settlement of a third party PPA with Western System Power Pool for the energy output in 2019 and 2020;
- PGE's purchase of PRC's interest in two associated power lines; and
- An "operating risk payment" from PRC to PGE

Q. Have you examined these components for prudence?

A. Yes. Staff conducted a thorough review of the Company's initial and supplemental testimony, received additional information through eight data requests, and held several discussions with the Company to understand the flow of finances and the financial analysis.

Q. What is the result of your analysis?

A. The first four components of the agreement are related to items whose costs and benefits are known or can be accurately estimated. For example, calculation of the value of the pre-existing coal inventory and equipment are known, and the value of the power purchase agreement obligations can be accurately estimated. The Company's Confidential workpaper "PRC_Economics_2-18-2014" provides a thorough spreadsheet model that calculates the necessary compensation to completely cover anticipated costs to ratepayers due to the first four components. These calculations are summarized in the Company's Confidential Exhibit 1502. In addition, the terms of the agreement allow for a true-up to actual costs for the estimated values,[1] which results in very little risk to customers.

Q. Please explain the purpose of the spreadsheet model cited above.

A. The spreadsheet details the costs and expected value of inventory and energy on an annual basis for the years 2014 through 2020 when coal generation ceases at Boardman. These costs and benefits are calculated and tabulated by five payment components. The payment components are described by the Company as the Boardman Purchase Payment, the Inventory Purchase, the Operating Risk Payment, the 2011 Power Purchase Agreement Settlement, and the Two Power Lines. I will explain how each component is calculated.

Q. Please describe the Boardman Purchase Payment.

A. This item reflects the net economic value of PRC's ten percent portion of the Boardman plant through 2020. The net economic value is calculated as the

[1] UE283-UE286/PGE/1500, Pope-Tooman/6 at 11-16

difference between the total operating cost of the plant and the revenues realized through the sale of energy. The Company first estimates net variable power costs (NVPC) and operations & maintenance (O&M) costs on an annual basis. The NVPC cost estimates are based primarily on projected fuel cost, rail car expenses, and transmission costs and offset by revenue from wholesale sales. O&M costs are estimated based on an extrapolation of actual O&M costs at an annual inflation rate of 1.93 percent. The total cost to operate the PRC portion of the plant offset by the wholesale value of the energy produced yields a negative net economic value for the plant. This is the amount that PRC is required to pay to PGE to make the net economic value of the plant equal to zero on a net present value basis. The amount of this Boardman Purchase Payment is also subject to true-up at the closing of the transaction. Taking into consideration both the validity of the estimates and the existence of the true-up, ratepayers assume virtually no risk for the Boardman Purchase Payment.

Q. Please describe the Inventory Purchase component.

A. PGE will pay PRC for the ten percent ownership PRC has in fuel stock and materials and supplies. This payment is based on actual material costs and is subject to true-up based on existing inventory at the time of closing. Since this inventory payment is based on actual costs and is subject to true-up, there is no risk to ratepayers.

Q. Please describe the 2011 Power Purchase Agreement (PPA) Settlement.

A. PRC and PGE had previously executed a PPA for PRC to deliver their portion of the plant output to PGE in 2019 and 2020, after PRC's PPA with the Turlock

Irrigation District expires in 2018.This payment component will compensate PGE for the value of the estimated wheeling expenses and line losses that were previously avoided under the original 2011 agreement. PGE will return the revenue from this settlement to customers via Schedule 105 (Regulatory Adjustments). This component represents a return of revenue to customers.

Q. Please describe the Two Power Lines.

A. PRC currently has partial ownership of two power transmission lines used to transmit power from the Boardman plant. PGE will assume PRC's ownership interest in these two lines and PGE will use the lines for both Boardman and its Carty generation plant. Recovery of costs related to these power lines will not be included in this rate case, and will be considered along with other Carty cost recovery.

Q. Please describe the Operating Risk Payment.

A. PGE will assume the additional decommissioning costs associated with the PRC ten percent share of the Boardman plant. The Company has estimated this cost based on a study by Black & Veatch which estimated the total decommissioning cost at about $68 million. The ten percent assumed cost ($6.8 million) is accounted for as part of the Boardman Purchase Payment. However, there are potential additional cost elements not included in the decommissioning estimate. PGE has recognized this and has calculated an additional risk payment required from PRC in order to cover these potential costs.

Q. Do you find a concern with the Operating Risk Payment?

A. Yes. This is the one item in the agreement that is difficult to value since it reflects the potential costs associated with decommissioning the plant. The purpose of this payment is to cover costs (and relieve risk) associated with both known and as-yet unknown potential costs associated with decommissioning.

Q. Is there a possibility for as-yet unknown costs associated with decommissioning the Boardman plant?

A. Yes. Although the Company has a reasonable analysis and estimate of the decommissioning costs performed by a reputable engineering firm, there is still potential for unforeseen costs due to potential environmental remediation. Some of these potential costs are already recognized – primarily the potential of additional cost for coal ash remediation. However, there may be other potential costs that are simply unrecognized at this time and will not be discovered until the time of decommissioning.

Q. Has the Company attempted to mediate this risk?

A. Yes. The operating risk premium has been calculated to provide financial insurance against these unknown and unforeseen costs.

Q. Is the operating risk premium adequate in light of the cost risk involved?

A. Staff has not yet reached a conclusion on this question. Staff is awaiting further information from the Company regarding the calculation of the operating risk premium.

Q. What are the next steps Staff will take to determine the adequacy of the risk premium payment?

A. To date the Company's testimony and discovery responses have not clearly identified the assumptions and calculation steps involved in determining the operating risk payment. Staff has requested data regarding these assumptions and a detailed description of the process the Company has used to determine the value of the payment. Upon receiving the required data and information, Staff will evaluate the Company's process and make a determination about whether the amounted collected is commensurate with the potential cost risk.

Q. If Staff determines that the amount PRC will pay to PGE as an operating risk premium is commensurate with the cost risk, will Staff have a recommendation regarding the entire transaction?

A. Yes. If Staff determines the operating risk premium is commensurate with the cost risk involved, Staff will recommend that the Commission accept the transaction as prudent and in the best interest of ratepayers .

Q. Does this conclude your testimony?

A. Yes

CASE: UE 283
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Witness Qualification Statement

June 11, 2014

WITNESS QUALIFICATION STATEMENT

NAME:	JOHN CRIDER
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR UTILITY ANALYST, ELECTRIC RESOURCES AND PLANNING
ADDRESS:	3930 Fairview Industrial Drive SE, SALEM, OR 97302
EDUCATION:	Bachelor of Science, Engineering, University of Maryland

EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since August of 2012. My current responsibilities include analysis and technical support for electric power cost recovery proceedings, with an emphasis on variable power costs and purchases from qualifying facilities. Prior to working for the OPUC I was an engineer in the Strategic Planning division for Gainesville Regional Utilities (GRU) in Gainesville, Florida. My responsibilities at GRU included analysis, design and support for generation economic dispatch modeling, wholesale power transactions, net metering, integrated resource planning, distributed solar generation and fuel (coal and natural gas) planning. Previous to working for GRU, I was a staff design engineer for Eugene Water & Electric Board (EWEB) where my responsibilities included design of control and communications system in support of water and hydro operations.

I am a registered professional engineer in both Oregon and Florida.